

**Hydro One Networks Inc.**

7<sup>th</sup> 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, Regulatory Affairs & Chief Risk Officer

BY COURIER

July 31, 2019

Ms. Kirsten Walli  
Board Secretary  
Ontario Energy Board  
Suite 2700, 2300 Yonge Street  
P.O. Box 2319  
Toronto, ON M4P 1E4

Dear Ms. Walli,

**EB-2019-0178 – B2M Limited Partnership's 2020-2024 Transmission Revenue Cap IR Application and Evidence Filing**

Hydro One Networks Inc., on behalf of B2M Limited Partnership ("B2M LP"), has submitted B2M LP's five-year Transmission Revenue Cap IR Application for the period 2020-2024 and prefiled evidence in support of the Application, using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System.

Given that B2M LP operates a single transmission asset, with minimal operating costs and no forecast capital expenditures, Hydro One proposes that this Application would be most effectively dealt with in written form. Moreover, Hydro One encourages the OEB to make provision for a Settlement conference to assist with the expediency of the application.

B2M LP will post electronic copies of the Application and supporting evidence on its [website](#) for public access. A text-searchable Adobe Acrobat electronic version and two paper copies of the Application will be sent to the OEB shortly.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea  
Submitting on behalf of B2M LP

1

## EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
<b>A</b>				<b>Administration</b>
A	1	1		Exhibit List
A	2	1		Application
A	2	1	1	Certification of Evidence
A	2	2		Compliance with Applicable Filing Requirements
A	2	2	1	Filing Requirement Checklist
A	2	3		Summary of Board Directives and Undertakings from Previous Proceedings
A	3	1		Executive Summary
A	4	1		Revenue Cap Application Summary
A	5	1		Description of the Partnership
A	6	1		Financial Information
A	6	2		B2M LP Financial Statements - Historical Years
A	6	2	1	2018 B2M Auditted Financials
A	6	2	2	2017 B2M Auditted Financials
A	6	3		Reconciliation of Regulatory Financial Results with Audited Financial Statements (2018)
A	6	4		Hydro One Limited - Historical Year Annual Report (2018)
A	6	4	1	2018 Annual Report
A	7	1		Draft Issues List
A	7	2		Witness List
A	7	3		Curricula Vitae
<b>B</b>				<b>Transmission System Plan</b>
B	1	1		Transmission System Overview
B	1	2		Strategic and Operational Plan
B	1	3		Summary of Capital Expenditures and In-Service Additions
B	1	3	1	Attachment 1: B2M LP Transmission System Plan
<b>C</b>				<b>Rate Base</b>
C	1	1		Rate Base
C	2	1		Statement of Utility Rate Base
C	2	2		Continuity of Accumulated Depreciation

Witness: Jeffrey Smith

<b>Exhibit</b>	<b>Tab</b>	<b>Schedule</b>	<b>Attachment</b>	<b>Contents</b>
C	2	3		Continuity of Property, Plant and Equipment
C	2	4		Fixed Asset Continuity Schedules: Dx Chapter 2 Appendix 2-BA
<b>D</b>				<b>Service Quality and Reliability Performance and Reporting</b>
D	1	1		Performance Measures
<b>E</b>				<b>Operating Revenue</b>
E	1	1		Revenue Requirement
E	1	2		Calculation of Revenue Requirement (2020)
<b>F</b>				<b>Operating Costs</b>
F	1	1		Operating Costs Summary
F	2	1		Summary of OM&A Expenditures
F	3	1		Affiliate Service Agreements
F	3	1	1	Attachment 1: Renewed Draft of B2M-HONI Agreement for provision of Operating and Mgmt Services
F	4	1		Common Corporate Costs, Cost Allocation Methodology
F	5	1		Depreciation Expenses
F	5	1	1	2017 Depreciation Rate Review Study
F	5	1	2	Depreciation and Amortization Expenses
F	5	1	3	Depreciation Letter
F	6	1		Taxes or Payment In Lieu of Corporate Income Taxes
F	6	1	1-4	Calculation of Utility Income Taxes Attachments
F	7	1		Income Tax Return
F	7	1	1	Income Tax Return 2018
F	8	1		Z-Factor Claims
<b>G</b>				<b>Cost of Capital and Capital Structure</b>
G	1	1		Capital Structure/Cost of Capital
G	1	2		Cost of Long-Term Debt Capital
G	1	3		Debt and Equity Summary
<b>H</b>				<b>Deferral and Variance Accounts</b>
H	1	1		Regulatory Accounts

<b>Exhibit</b>	<b>Tab</b>	<b>Schedule</b>	<b>Attachment</b>	<b>Contents</b>
H	1	2		Continuity Schedule - Regulatory Accounts
<b>I</b>				<b>Cost Allocation and Rate Design</b>
I	1	1		Cost Allocation and Rate Design
I	2	1		Overview of Uniform Transmission System Rates
I	3	1		Current Ontario Transmission Rate Schedules
I	3	1	1	Attachment 1: 2019 Ontario Uniform Transmission Rate Schedule
I	3	1	2	Attachment 2: 2019 Uniform Transmission Rates and Revenue Disbursement Allocators
I	4	1		Proposed Ontario Transmission Rate Schedules
I	4	1	1	Attachment 1: 2020 Ontario Uniform Transmission Rate Schedule
I	4	1	2	Attachment 2: 2020 Uniform Transmission Rates and Revenue Disbursement Allocators



- 1 a) B2M LP's total revenue requirement for the 2020 Test Year, determined by  
2 using a cost of service, forward test-year approach;  
3
  - 4 b) An amendment to the Uniform Transmission Rates for the Network pool to  
5 allow for the recovery of B2M LP's proposed rates revenue requirement for  
6 2020, to be effective and implemented on January 1, 2020;  
7
  - 8 c) The proposed Revenue Cap Index mechanism to set B2M LP's transmission  
9 revenue requirement and Uniform Transmission Rates for the Network pool  
10 for the period effective January 1, 2021. through December 31, 2024, as  
11 described in Exhibit A, Tab 4, Schedule 1;  
12
  - 13 d) The continuation of B2M LP's current regulatory accounts;  
14
  - 15 e) Accounting Orders establishing an Earnings Sharing Mechanism Deferral  
16 Account effective January 1, 2020, as described in Exhibit H, Tab 1, Schedule  
17 1;  
18
  - 19 f) Other items or amounts that may be requested by B2M LP in the course of  
20 this proceeding, and as may be granted by the OEB.  
21
- 22 4. This application has been prepared in accordance with the OEB's *Filing*  
23 *Requirements for Electricity Transmission Rate Applications* dated February 11,  
24 2016.  
25
  - 26 5. The written evidence filed with the OEB may be amended from time to time prior to  
27 the OEB's final decision on the Application.

- 1 6. B2M LP may seek meetings with Board staff and intervenors in an attempt to identify  
2 and reach agreements to settle issues arising out of this Application.

3  
4 **NOTICE AND FORM OF HEARING REQUESTED**

- 5  
6 7. B2M LP operates a transmission line in Ontario that benefits customers across the  
7 province. Notice of this Application should be published so as to reach the largest  
8 number of customers across Ontario in an efficient manner.

- 9  
10 8. The Application may be viewed on the Internet at the following address:  
11 <http://www.b2mlp.ca/rate-applications/>

- 12  
13 9. B2M LP requests that this Application be heard by way of a written hearing.

14  
15 **PROPOSED EFFECTIVE DATE**

- 16  
17 10. B2M LP requests that the OEB's rate orders be effective January 1, 2020. To address  
18 the possibility that the requested rate orders cannot be made effective by that time,  
19 B2M LP requests an interim Order making its current transmission revenue  
20 requirement and charges effective on an interim basis as of January 1, 2020, and the  
21 use of the existing Forgone Revenue Deferral Account to recover any differences  
22 between the interim rates and the final rates effective January 1, 2020, based on the  
23 OEB's Decision and Order herein.

- 24 11. The persons affected by this Application are the ratepayers of the transmission system  
25 in Ontario. It is impractical to set out their names and addresses because they are too  
26 numerous.

1 **CONTACT INFORMATION**

2  
3 12. B2M LP requests that a copy of all documents filed with the Board by each party to  
4 this Application be served on the Applicant and the Applicant's counsel as follows:

5  
6 a) The Applicant:

7  
8 Ms. Linda Gibbons  
9 Senior Regulatory Coordinator – Regulatory Affairs  
10 Hydro One Networks Inc.

11  
12 Address for personal service: 7<sup>th</sup> Floor, South Tower  
13 483 Bay Street  
14 Toronto, ON M5G 2P5

15  
16 Mailing Address: 7<sup>th</sup> Floor, South Tower  
17 483 Bay Street  
18 Toronto, ON M5G 2P5

19  
20 Telephone: (416) 345-4373

21 Fax: (416) 345-5395

22 Electronic access: [Regulatory@HydroOne.com](mailto:Regulatory@HydroOne.com)

23  
24 b) The Applicant's counsel:

25  
26 Michael Engelberg  
27 Assistant General Counsel  
28 Hydro One Networks Inc.

1 Address for personal service: 8<sup>th</sup> Floor, South Tower  
2 483 Bay Street  
3 Toronto, ON M5G 2P5  
4

5 Mailing Address: 8<sup>th</sup> Floor, South Tower  
6 483 Bay Street  
7 Toronto, ON M5G 2P5  
8

9 Telephone: (416) 345-6305

10 Fax: (416) 345-6972

11 Electronic access: [mengelberg@HydroOne.com](mailto:mengelberg@HydroOne.com)  
12

13 DATED at Toronto, Ontario, this 31<sup>st</sup> day of July, 2019.  
14

15 by B2M LIMITED PARTNERSHIP

16 By its counsel,  
17

18 ORIGINAL SIGNED BY MICHAEL ENGELBERG  
19

20 \_\_\_\_\_  
Michael Engelberg

## CERTIFICATION OF EVIDENCE

B2M Limited Partnership  
A limited partnership under the laws of Ontario  
(hereinafter, "B2M LP")

TO: THE ONTARIO ENERGY BOARD

---

The undersigned, Jeffrey Smith, hereby certifies for and on behalf of B2M LP that:

1. I am the Managing Director of Hydro One Indigenous Partnerships GP Inc., the General Partner for B2M LP;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's Filing Requirements for Electricity Transmission Applications (last revised on February 11, 2016); and
3. The evidence submitted in support of B2M LP's 2020 revenue requirement application (EB-2019-0178) filed with the Ontario Energy Board is accurate, consistent and complete to the best of my knowledge.

DATED this 31st day of July, 2019.

ORIGINAL SIGNED BY JEFFREY SMITH

---

Jeffrey Smith  
for B2M LP by its General Partner, Hydro One  
Indigenous Partnerships GP Inc.

Witness: Jeffrey Smith

1                   **COMPLIANCE WITH OEB FILING REQUIREMENTS FOR**  
2                                   **ELECTRICITY TRANSMITTERS**

3  
4 B2M LP has prepared this Application in alignment with the OEB’s guidance in its *Filing*  
5 *Requirements for Electricity Transmission Rate applications* (February 11, 2016)  
6 (“Transmission Filing Requirements”). B2M LP has presented the content to align with  
7 Chapter 2 of the Transmission Filing Requirements (“Chapter 2”). To assist the OEB in  
8 its review of the Application, B2M LP has prepared a checklist of the Transmission  
9 Filing Requirements including the relevant evidentiary references for each item. This  
10 checklist is provided as Attachment 1 to this Exhibit in the worksheet labelled  
11 “*Transmission Filing Reqs*”.

12  
13 Given the unique nature of the B2M LP’s assets and the role they play in the transmission  
14 of electricity in the province, a number of Transmission Filing Requirements are not  
15 applicable. These include:

16  
17 **1. Customer Engagement**

- 18       • B2M LP does not have any direct customers, and hence has not performed any  
19       customer engagement activities and analysis.

20  
21 **2. Transmission System Plan**

- 22       • B2M LP has prepared an abridged Transmission System Plan (“TSP”) given that  
23       it is not proposing capital expenditures during the rate period and as such, not all  
24       filing requirements are applicable.
- 25       • Section 2.4 of Chapter 2 states that transmitters may wish to refer to Chapter 5 of  
26       the OEB’s Filing Requirements for Electricity Distributors, Consolidated  
27       Distribution System Plan Filing Requirements (“DSP Requirements”) for further

Witness: Kathleen Burke

1 guidance on the content and structure of a TSP. B2M LP has adopted the DSP  
2 Requirements to guide the preparation of its abridged TSP. B2M LP has prepared  
3 a checklist of the DSP Requirements including the relevant evidentiary references  
4 for each item. This checklist is provided as Attachment 1 to this Exhibit in the  
5 worksheet labelled “*DSP Checklist*”.

6 • The assets owned by B2M LP are relatively new and approximately 90% of the  
7 line is less than ten years old. As such, B2M LP is not proposing any capital  
8 expenditure in this Application, and hence did not undertake a capital expenditure  
9 planning process, or participate in a regional planning process. B2M LP has not  
10 provided external cost benchmarking, justification for capital expenditures, or  
11 details on material investments as none are included in this Application.

12

### 13 **3. Working Capital Allowance**

14 • As established in B2M LP’s previous transmission rates application (EB-2015-  
15 0026), there is no need for a working capital allowance.

16

### 17 **4. Economic Overview / Load Forecast**

18 • B2M LP’s asset base consists of one 500 kV transmission line comprising of two  
19 circuits with no delivery points. Hence, B2M LP has no discrete, incremental load  
20 determinants to include in the UTR forecast.

21 • The only rate pool applicable for B2M LP assets is the “Network” pool consistent  
22 with the cost allocation methodology approved by the OEB in proceeding EB-  
23 2015-0026 for B2M LP’s transmission rates. Therefore, no further cost allocation  
24 methodology is presented in this application.

1 **5. Other Revenue**

- 2 • B2M LP has no external revenue sources, the only revenue applicable to B2M LP  
3 is the revenue requirement from owning and maintaining its 500 kV transmission  
4 line.

5  
6 **6. Employee Compensation**

- 7 • B2M LP has no employees. Operations and management services are provided by  
8 Hydro One by a service level agreement as outlined in Exhibit F, Tab 3, Schedule  
9 1.

10  
11 Where applicable, B2M LP has incorporated the Chapter 2 appendices from the *Filing*  
12 *Requirements for Electricity Distributors* to support its evidence. These are listed in  
13 Attachment 1 to this Exhibit and are provided throughout the Application.

14  
15 In preparing this Application, B2M LP followed the expectations of a Revenue Cap Index  
16 application provided in the Transmission Filing Requirements:

17  
18 **Term:** 5 years (rebasings plus 4 years)

19  
20 **Index for the Annual Rate Adjustment:** The proposed Revenue Cap Index includes an  
21 industry-specific inflation factor and a productivity factor as outlined in Exhibit A, Tab 4,  
22 Schedule 1.

23  
24 **Benchmarking:** Operations and management services are provided to B2M LP through a  
25 service level agreement with Hydro One Networks Inc. These types of activities are  
26 subject to review through Hydro One Networks Inc.'s external benchmarking evidence  
27 provided in its transmission rate applications.

Witness: Kathleen Burke

1 **Performance Metrics:** B2M LP proposes to track its performance utilizing a set of  
2 outcome measures as documented in Exhibit D, Tab 1, Schedule 1 to ensure that B2M LP  
3 meets its five year plan. The proposed metrics align with the RRF outcomes of  
4 operational effectiveness, financial performance and public policy responsiveness.<sup>1</sup>

5  
6 **Updates:** B2M LPs proposal contains an update in 2021 to align its cost of long-term  
7 debt with the actual market rate of its debt refinancing as documented in Exhibit G, Tab  
8 1, Schedule 1.

9  
10 **Protecting Customers:** Exhibit A, Tab 4, Schedule 1 outlines B2M LP's proposed  
11 Earnings Sharing Mechanism which shares the benefit of productivity improvements with  
12 customers during the term and provides rate payers with protection from utility earnings  
13 that may exceed proposed levels.

---

<sup>1</sup> Customer Focus has been excluded as B2M LP does not have any direct customers.

## Transmission Filing Requirements Checklist

### B2M LP

Filing Requirement Page # Reference		Date: February 11, 2016	Yes/No/N/A	Evidence Reference, Notes
<b>GENERAL REQUIREMENTS</b>				
Ch 1, p 2	Certification that the evidence filed is accurate, consistent and complete		Yes	Exhibit A, Tab, 2, Schedule 1, Attachment 1
3	Confidential Information - Practice Direction has been followed		Yes	
Ch 2, p 4	Provide Chapter 2 appendices that are applicable to transmission applications <i>Not applicable:</i> 2-AC on Customer Engagement, 2-G SQI, 2-H Other Operating Reve, 2-I/2-IA/2-IB Load Forecast/CDM, 2-JC OMA Programs, 2-K Employee Costs, 2-N OMA/FTE		Yes	2-AA/2-AB Capital Program/Expenditures: Exhibit B, Tab 1, Schedule 3, Attachment 1
4	Written direct evidence is to be included before data schedules		Yes	
4	Average of the opening and closing fiscal year balances must be used for items in rate base		Yes	Exhibit C, Tab 1, Schedule 1
4	Total capitalization (debt and equity) must equate to total rate base		Yes	Exhibit G, Tab 1, Schedule 1 and Exhibit C, Tab 1, Schedule 1
4	Data for the following years, at a minimum, must be provided: Test year = prospective rate year; Bridge year = current year; Four most recent historical years; Most recent OEB-approved test year		Yes	
4	<i>Not applicable:</i> 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		N/A	Revenue Cap IR Proposed
4	Documents are to be provided in bookmarked and text-searchable Adobe PDF format		Yes	
4	Tables must also be provided in working Microsoft Excel spreadsheet format where available and practical		Yes	
6	Materiality threshold		Yes	
6	State accounting standard(s) used in historical, bridge and test years and summarize changes since last filing		Yes	Exhibit A, Tab 6, Schedule 1

<b>EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS</b>				
<i>Executive Summary</i>				
Ch 2, p 8	Overview of past and expected future performance, business plan and objectives and how they align with RRFE objectives		Yes	Exhibit A, Tab 3, Schedule 1
8	Summary identifying key elements of the proposals and the Business Plan underpinning application, as guided by RRFE including <i>Not applicable: customer feedback reflected in the transmitter's objectives</i>		Yes	Exhibit A, Tab 3, Schedule 1
8	Revenue Requirement - request, changes from previous revenue requirement and drivers of change		Yes	Exhibit A, Tab 3, Schedule 1
8	Budgeting Assumptions - Economic overview <i>Not applicable: no capital expenditures</i>		No	Exhibit A, Tab 3, Schedule 1
8	<i>Not applicable: Load Forecast - Load growth and forecast methods</i>		No	Exhibit A, Tab 3, Schedule 1
9	TSP - Summary of drivers and elements of plan, details of investment planning process, capital expenditures requested for test years, changes in capital expenditures from OEB approved		Yes	Exhibit A, Tab 3, Schedule 1
9	Rate Base - Request for test years and change from last OEB approved		Yes	Exhibit A, Tab 3, Schedule 1
9	Performance and Reporting - Proposed scorecard Reporting limited to the 5 metrics in the EB-2015-0026 Decision		Yes	Exhibit A, Tab 3, Schedule 1
9	OM&A - Request for test years, changes from last OEB approved and drivers of change		Yes	Exhibit A, Tab 3, Schedule 1
9	Cost of Capital - Whether cost of capital parameters are being used and rationale for deviations from methodology		Yes	Exhibit A, Tab 3, Schedule 1
9	Cost Allocation + Rate Design - Summary of how costs are allocated to rate pools		Yes	Exhibit A, Tab 3, Schedule 1
10	Deferral and Variance Accounts - Accounts requested for disposition, total disposition and disposition period and new deferral and variance accounts		Yes	Exhibit A, Tab 3, Schedule 1
10	Bill Impacts - Summary of impacts at wholesale level and for typical retail customers		Yes	Exhibit A, Tab 3, Schedule 1
<i>Customer Engagement</i>				
Ch 2, p 10	<i>Not applicable: B2M LP has no customers</i> Customer engagement process and activities		N/A	
10	Customer needs including end-use load customers and generator customers		N/A	
10	How the application responds to customer needs		N/A	
10	Customer satisfaction surveys		N/A	
10	Appendix 2AC in the Distribution Filing Requirements helpful in structuring this evidence		N/A	
11	Responses to letters of comment		N/A	

<i>Financial Information</i>			
Ch 2, p 11	Non-consolidated Audited Financial Statements for 2 most recent years (i.e. 3 years of historical actuals)	Yes	Exhibit A, Tab 6, Schedule 2
11	Detailed reconciliation of AFS with regulatory financial results	Yes	Exhibit A, Tab 6, Schedule 3
11	Annual Report and MD&A for most recent year of parent company	Yes	Exhibit A, Tab 6, Schedule 4
11	Rating Agency Reports: <i>B2M LP Debt is managed and rated under Hydro One Networks</i>	N/A	EB-2019-0082: Exhibit A, Tab 6, Schedule 3
11	Prospectuses & information circulars for recent and planned public offerings: <i>B2M LP Debt is managed and rated under Hydro One Networks</i>	N/A	EB-2019-0082: Exhibit A, Tab 6, Schedule 5
<i>Administration</i>			
Ch 2, p 11	Table of Contents	Yes	Exhibit A, Tab 1, Schedule 1
11	Statement identifying customers materially affected by the application	Yes	Exhibit A, Tab 2, Schedule 1
12	Internet address for viewing of application	Yes	Exhibit A, Tab 2, Schedule 1
12	Primary contact information (name, address, phone, fax, email)	Yes	Exhibit A, Tab 2, Schedule 1
12	Identification of legal representation	Yes	Exhibit A, Tab 2, Schedule 1
12	Requested effective date	Yes	Exhibit A, Tab 2, Schedule 1
12	Bill impacts for typical Ontario residential customer an Ontario General Service customer	Yes	Exhibit A, Tab 3, Schedule 1
12	Form of hearing requested (written or oral)	Yes	Exhibit A, Tab 2, Schedule 1
12	List of approvals requested including accounting orders	Yes	Exhibit A, Tab 2, Schedule 1
12	Proposed length of the term and proposed method for establishing revenue requirement for each year of the term	Yes	Exhibit A, Tab 2, Schedule 1
12	Changes in tax status	Yes	Exhibit A, Tab 6, Schedule 1
12	Existing Accounting Orders	Yes	Exhibit H, Tab 1, Schedule 1
12	Map of assets and operations showing where the utility operates within the province, and the communities serviced by the utility.	Yes	Exhibit B, Tab 1, Schedule 1
12	Corporate and utility organizational structure, planned changes, rationale for changes and cost impact	Yes	Exhibit A, Tab 5, Schedule 1
13	The Accounting Standard used and when it was adopted	Yes	Exhibit A, Tab 6, Schedule 1
13	Deviations from filing requirements, if any	N/A	
13	Changes to methodologies used in previous applications	Yes	Exhibit A, Tab 6, Schedule 1
13	Confirmation that accounting treatment is segregated for non-regulated business	Yes	Exhibit A, Tab 6, Schedule 1
13	Indication of how prior OEB Decisions or Orders have been satisfied and impact on current application	Yes	Exhibit A, Tab 2, Schedule 2

<b>EXHIBIT 2 - Transmission System Plan</b>				
<b>General</b>				
		<i>Note: B2M LP has no planned Capital Expenditures</i>		
Ch 2, p 13		Refer to Chapter 5 of the Distribution Filing Requirements	Yes	
13		The strategic plan for the utility and investment strategy	Yes	Exhibit B, Tab 1, Schedule 2
13		The longer term economic and planning assumptions	N/A	
13		The asset management plan	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3
13		A description of how investments are prioritized and selected	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3
13		A discussion of transmission investments identified in the regional planning process	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2
13		Highlights of recent and proposed investments and their fit with the strategic plan	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
13		A description of how the needs of customers and overall system planning policy objectives are being reflected	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.1.2
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	N/A	
<b>Asset Management Plan</b>				
Ch 2, p 14		Asset management policy, strategy and objectives	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3
14		Inventory and assessment of the condition of capital assets (by class and inclusion in BES), how this informs plan for capital expenditures and maintenance expenditures	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.2
14		Identify NERC exemptions, planned or in progress NERC exemption requests and associated costs if exemption denied	N/A	
<b>Regional Considerations</b>				
Ch 2, p 14		Regional planning process demonstrating that regional considerations have been considered and addressed	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2
14		Final Regional Infrastructure Plan describing investments in transmission or distribution facilities in the TSP	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2
14		Identify investments spanning more than one region	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2

<i>Coordinated Planning with Third Parties</i>			
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	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2
<i>Capital Expenditures</i>			
Ch 2, p 16	<i>Note: B2M LP has no planned Capital Expenditures</i> 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	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
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	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
16	Drivers of capital expenditure increases for the test year(s)	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
16	The basis for the estimated budget for the project or program	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
16	For the balance of capital expenditures, describe components of capital expenditure and provide a reconciliation of capital components to total capital budget	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
17	Written explanation of capital expenditure variances	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
17	The proposed accounting treatment, including the treatment of cost of funds, for investments spanning more than one year	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
17	Cost benchmarking studies or utility cost comparisons	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
17	Continuous improvement or efficiency gains, how they will be achieved and benefit customers	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4
17	A proposal to mitigate the potential for any significant earning by the transmitter above the regulatory net income	Yes	Exhibit A, Tab 4, Schedule 1

<b>EXHIBIT 3 - Rate Base</b>				
<b>Overview</b>				
Ch 2, p 17	Opening and closing balances and the averages thereof gross assets and accumulated depreciation Rate base shall include an allowance for working capital Rate base must be supported by historical actuals, bridge year and test years		Yes	Exhibit C, Tab 1, Schedule 1
18	Continuity statements (year end balance, including interest during construction and overheads). Explanation for any restatement (e.g. due to change in accounting standards) Year over year variance analysis; explanation where variance greater than materiality threshold Hist. OEB-Approved vs Hist. Actual Hist. Act. vs. preceding Hist. Act. Hist. Act. vs. Bridge Bridge vs. Test		Yes	Exhibit C, Tab 2, Schedules 2 to 4
18	Opening and closing balances of gross assets and accumulated depreciation must correspond to fixed asset continuity statements. Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation		Yes	Exhibit C, Tab 1, Schedule 1 Exhibit C, Tab 2, Schedule 4
19	Information outlined in the fixed asset continuity schedule is provided for each year, in both the application material and in working Microsoft Excel format.		Yes	Exhibit C, Tab 1, Schedule 1 Exhibit C, Tab 2, Schedule 4
<b>Gross Assets - PP&amp;E and Accumulated Depreciation</b>				
Ch 2, p 19	Breakdown by function (transmission plant, general plant, other plant) for required statements and analyses		Yes	Exhibit C, Tab 2, Schedule 4
19	Detailed breakdown by major plant account for each functionalized plant item; For the test year(s), each plant item must be accompanied by a description.		Yes	Exhibit C, Tab 2, Schedule 4
19	Detailed breakdown of the in-service capital additions for the test year(s)		Yes	Exhibit C, Tab 1, Schedule 1
19	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account		Yes	Exhibit C, Tab 2, Schedule 4
<b>Allowance for Working Capital</b>	<b>Not Applicable: B2M LP requires no working capital</b>		N/A	Exhibit C, Tab 1, Schedule 1
Ch 2, p 19	Working Capital - Lead/Lag Study		N/A	
19	Lead/Lag Study - leads and lags measured in days, dollar-weighted		N/A	
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.		N/A	
<b>Customer Connection and Cost R</b>	<b>Not Applicable: B2M LP has no customer driven Capital Expenditures</b>		N/A	
Ch 2, p 20	The transmitter should show customer contribution amounts separately as an offset to rate base.		N/A	
20	Agreements reviewed on reaching a fifth anniversary and aggregated estimate of total expected true-up contributions and proceeds from bypass agreements		N/A	
20	Financial and regulatory accounting treatment of true-up proceeds.		N/A	
<b>Capitalization Policy</b>	<b>Not Applicable: B2M LP has no overhead capitalized</b>		N/A	
Ch 2, p 20	Capitalization policy, including changes since the last revenue requirement application		N/A	
20	Overhead costs on self-constructed assets		N/A	
20	Identification of burden rates and burden rates prior to changes, if any		N/A	
<b>Capital Module</b>				
Ch 2, p 21	Revenue Cap index may request a capital increment for discrete projects being placed in service after the rebasing year that are part of the Transmission System Plan; intended to come into service during the index period; Involve costs that the transmitter cannot manage through the revenue established through the index		N/A	
21	The request must address proposed approval criteria (materiality, need, prudence) and the process for implementation of the recovery of the capital increment.		N/A	

<b>EXHIBIT 4 - Service Quality and Reliability Performance and Reporting</b>		
<i>Proposed Scorecard</i>		
21	<i>Scope: Reporting limited to the 5 metrics in the EB-2015-0026 Decision</i> Propose a five-year scorecard including measures for public policy responsiveness, operational effectiveness, customer focus, financial performance and other relevant measures	Yes Exhibit D, Tab 1, Schedule 1
<i>Reliability Performance</i>		
22	<i>Scope: Reporting limited to the 5 metrics in the EB-2015-0026 Decision</i> Reliability performance measures: transmission frequency of delivery point interruptions, transmission duration of delivery point interruptions, unsupplied energy in minutes, transmission system unavailability	Yes Exhibit D, Tab 1, Schedule 1
22	Address performance standards for transmitters as set out in Chapter 4 of the TSC.	N/A
22	Compare system performance with other systems both nationally and internationally	N/A
<i>Compliance Matters</i>		
22	Discuss any outstanding areas of non-compliance which have had an effect on the application, including any relief sought through this application to resolve the non-compliance	Yes Exhibit B, Tab 1, Schedule 1
<b>EXHIBIT 5 - Operating Revenue</b>		
<i>Load and Revenue Forecasts</i>		
23	<i>Not Applicable: B2M LP has no load forecast</i> Explanation of causes, assumptions and adjustments for volume forecast. Economic assumptions and data sources for customer and load forecasts	N/A
23	Explanation of weather normalization methodology. Describe economic models, econometric models, end-user models customer forecast surveys and load shape analyses	N/A
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	N/A
23	Impact of forecast embedded generation on the transmission system load accounted for	N/A
<i>Accuracy of Load Forecast and V<sub>e</sub></i>		
23	<i>Not Applicable: B2M LP has no load forecast</i> 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	N/A
24	<i>Not Applicable: B2M LP has no load forecast</i> 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)	N/A
24	All data used to determine the forecasts must be presented and filed in live MS Excel spreadsheet format	N/A

<b>Other Revenue</b>		<i>Not Applicable: B2M LP has no other revenue</i>		
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	N/A	
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	N/A	
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	N/A	
24		Revenues or costs (including interest) associated with deferral and variance accounts must not be included in other revenue.	N/A	
<b>EXHIBIT 6 - Operating Cost</b>				
<i>Overview</i>				
Ch 2, p 25		Brief explanation of test year OM&A levels, cost drivers, significant changes, trends, inflation rate assumed, business environment changes, benchmarking, description of the continuous improvement or efficiency gains	Yes	Exhibit F, Tab 1, Schedule 1
<b>Summary and Cost Driver Tables</b>				
Ch 2, p 26		Summary of recoverable OM&A expenses	Yes	Exhibit F, Tab 2, Schedules 1
26		Recoverable OM&A cost drivers	Yes	Exhibit F, Tab 2, Schedules 1
26		Change in OM&A in test year attributable to a change in capitalized overhead	N/A	
26		OM&A variance analysis for test year with respect to bridge and historical years	Yes	Exhibit F, Tab 2, Schedules 1
<b>Program Delivery Costs with Variance Analysis</b>				
Ch 2, p 26		O&M Costs for: - <del>employee compensation</del> - <del>shared services</del> - corporate cost allocation - <del>purchase of non-affiliate services</del> - one-time costs - OEB costs - Charitable and political donations	Yes	Exhibit F, Tab 2, Schedules 1
<b>Employee Compensation</b>				
Ch 2, p 26		<i>Not Applicable: B2M LP has no employees</i> Employee complement, compensation and benefits	N/A	
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	N/A	
27		Employee benefit programs including pensions	N/A	
27		Most recent actuarial reports	N/A	

<b>Shared Services and Corporate Cost Allocation</b>				
Ch 2, p 27	Identification of shared services		Yes	Exhibit F, Tab 2, Schedule 1
27	Allocation methodology for corporate and shared services		Yes	Exhibit F, Tab 4, Schedule 1
28	Details for services provided or received for historical, bridge and test years. Reconciliation of revenue arising from transactions must be included in other revenue in Operating Revenue section		Yes	Exhibit F, Tab 2, Schedule 1
28	Variance analysis - test year vs last OEB approved and most recent actual		Yes	Exhibit F, Tab 2, Schedule 1
28	Identification of any Board of Director costs for affiliates included in LDC costs		N/A	
<b>Purchase of Non-Affiliate Services</b>				
28	Procurement Policy		N/A	
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	
<b>One-time Costs</b>				
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.		No	Exhibit F, Tab 1, Schedule 1
<b>Regulatory Costs</b>				
28	Regulatory costs - breakdown of actual and forecast costs Supporting information, legal fees, consultant fees, costs awards, etc.		Yes	Exhibit F, Tab 2, Schedule 1
<b>Charitable and Political Donations</b>				
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	
29	Detailed information for all contributions that are claimed for recovery		N/A	
29	Charitable Donations - confirmation that political contributions not included		N/A	
<b>Depreciation, Amortization and Depletion</b>				
29	Depreciation, Amortization and Depletion details by asset group for historical, bridge and test years. Asset amount and rate of depreciation/amortization must tie back to the accumulated depreciation balances in the continuity schedule under rate base.		Yes	Exhibit F, Tab 5, Schedule 1
29	Identification of any Asset Retirement Obligations and associated depreciation, accretion expense		Yes	Exhibit F, Tab 5, Schedule 1
29	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided		Yes	Exhibit F, Tab 5, Schedule 1
29	Depreciation/amortization policy Summary of changes to depreciation/amortization policy since last CoS		Yes	Exhibit F, Tab 5, Schedule 1, Attachment 1 and 3
29	Explanation of any deviations from depreciating components of PP&E separately		N/A	

<i>Taxes or PILs and Property Taxes</i>				
30	Income tax or PILs calculations, derivation of adjustments for historical, bridge, test years	Yes	Exhibit F, Tab 6, Schedule 1	
30	Supporting schedules and calculations identifying reconciling items	Yes	Exhibit F, Tab 6, Schedule 2 Attachments 1 to 4	
30	Most recent federal and provincial tax returns	Yes	Exhibit F, Tab 7, Schedule 3 and Attachments 1	
30	Financial Statements included with tax returns if different from those filed with application	N/A		
30	Calculation of Tax Credits; redact where required (filing of unredacted versions is not required)	N/A		
30	Supporting schedules, calculations and explanations for other additions and deductions	Yes	Exhibit F, Tab 6, Schedule 1	
<i>Non-recoverable and Disallowed Expenses</i>				
30	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	N/A		
<i>Integrity Checks</i>				
31	Depreciation and amortization added back in the application's PILs/tax model agree with the numbers disclosed in the rate base section of the application	Yes	Exhibit F, Tab 6, Schedule 1	
31	The capital additions and deductions in the UCC/CCA Schedule 8 agree with the rate base section for historic, bridge and test years	Yes	Exhibit F, Tab 6, Schedule 1	
31	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31st historic year UCC that agrees with the opening bridge year UCC at January 1st	Yes	Exhibit F, Tab 6, Schedule 1	
31	The CCA deductions in the application's PILs/tax model for historic, bridge and test years agree with the numbers in the UCC schedules for the same years filed	Yes	Exhibit F, Tab 6, Schedule 1	
31	Loss carry-forwards, if any, from the tax returns (Schedule 4) agree with those disclosed in the application	Yes	Exhibit F, Tab 6, Schedule 1	
31	CCA is maximized even if there are tax loss carry-forwards	Yes	Exhibit F, Tab 6, Schedule 1	
31	A statement is included in the application as to when the losses, if any, will be fully utilized	Yes	Exhibit F, Tab 6, Schedule 1	
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 F, Tab 6, Schedule 1	
31	The income tax rate used to calculate the tax expense must be consistent with the utility's actual tax facts and evidence filed in the proceeding.	Yes	Exhibit F, Tab 6, Schedule 1	
<i>Z-Factor Claims</i>				
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	Yes	Exhibit F, Tab 8, Schedule 1	

<b>EXHIBIT 7 - COST OF CAPITAL AND CAPITAL STRUCTURE</b>				
<i>Capital Structure</i>				
33	OEB's cost of capital parameters used	Yes	Exhibit G, Tab 1, Schedule 1	
33	Multi-year revenue requirement approvals must indicate whether cost of capital will be updated annually or fixed for all test years	Yes	Exhibit G, Tab 1, Schedule 1	
33	Long-term debt; Short-term debt; Preference shares and Common equity must be presented with the appropriate schedules	Yes	Exhibit G, Tab 1, Schedule 3	
33	Explanation for any changes in capital structure	Yes	Exhibit G, Tab 1, Schedule 1	
<i>Cost of Capital (Return on Equity and Cost of Debt)</i>				
34	Calculation of cost for each capital component	Yes	Exhibit G, Tab 1, Schedule 1	
34	Profit or loss on redemption of debt	Yes	Exhibit G, Tab 1, Schedule 1	
34	Copies of promissory notes or other debt arrangements with affiliates	Yes	Exhibit G, Tab 1, Schedule 1	
34	Explanation of debt rate for each existing debt instrument	Yes	Exhibit G, Tab 1, Schedule 1	
34	Forecast of new debt in bridge and test year - details including estimate of rate	Yes	Exhibit G, Tab 1, Schedule 1	
34	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Yes	Exhibit G, Tab 1, Schedule 1	
<i>Not-for-Profit Corporations</i>				
34	Not for Profit Corporations - evidence that excess revenue is used to build up operating and capital reserves	N/A		
<b>EXHIBIT 8 - DEFERRAL AND VARIANCE ACCOUNTS</b>				
34	List of all outstanding DVA and sub-accounts; provide description of DVAs	Yes	Exhibit H, Tab 1, Schedule 1	
34	Completed DVA continuity schedule for period following last disposition to present - live Excel format	Yes	Exhibit H, Tab 1, Schedule 2	
34	Confirm use of interest rates established by the OEB by month or by quarter for each year	Yes	Exhibit H, Tab 1, Schedule 1	
35	Explanation if account balances in continuity schedule differs from trial balance in RRR and AFS	Yes	Exhibit H, Tab 1, Schedule 1	
35	A proposal for an allocator based on the proposed cost driver(s) and included in the continuity schedule	Yes	Exhibit I1, Tab 1, Schedule 3	
35	Statement as to any new accounts, and justification.	Yes	Exhibit H, Tab 1, Schedule 1	
35	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis; explanation, amount of adjustment and supporting documents	Yes	Exhibit H, Tab 1, Schedule 1	
<i>Disposition of Deferral and Variance Accounts</i>				
36	Identify accounts for which disposition is sought	No	Exhibit H, Tab 1, Schedule 1	
36	Identify accounts for which disposition is not sought and the reasons	No	Exhibit H, Tab 1, Schedule 1	
36	Propose the method to be used for recovery or refund of balances that are proposed for disposition	No	Exhibit H, Tab 1, Schedule 1	
36	Provide a statement that the balances proposed for disposition before forecasted interest are consistent with the last Audited Financial Statements	No	Exhibit A, Tab 6, Schedule 3, Exhibit H, Tab 1, Schedule 1	
36	Provide an explanation for any variances greater than 5% between amounts proposed for disposition before forecasted interest and the amounts reported in the applicant's quarterly and annual RRR filings for each account	N/A		
36	Provide explanations even if such variances are below the 5% threshold if the variances in question relate to: (1) matters of principle (i.e. prior OEB decisions, and prior period adjustments); and/or, (2) the cumulative effect of immaterial differences over several accounts totaling to a material difference	N/A		
36	Show all relevant calculations, including the rationale for the allocation of each account, the proposed billing determinants and the length of the disposition period	N/A		

<b>EXHIBIT 9 - Cost Allocation to Uniform Transmission Rate Pools: Charge Determinants</b>				
		<i>Scope: B2M LP is allocated to the Network Pool</i>		
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 I, Tab 1, Schedule 1	
36	Steps taken to functionalize the assets in the functional categories	Yes	Exhibit I, Tab 1, Schedule 1	
36	Allocation of revenue requirement to the rate pools and allocation factors for each asset or groups of assets	N/A		
36	Assignment of depreciation, return on capital, taxes and OM&A costs to rate pools and non-standard rate pools	N/A		
<b>EXHIBIT 10 - Rate Design for Uniform Transmission Rates</b>				
	<i>Bill Impact Information</i>			
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 I, Tab 2, Schedule 1	
37	Bill impacts for typical customers and consumption levels.	Yes	Exhibit I, Tab 2, Schedule 1	
	<i>Setting the Uniform Transmission Rates</i>			
37	Overview of how the UTR are established in Ontario and how these rates are determined	Yes	Exhibit I, Tab 2, Schedule 1	
37	The revenue requirement and load forecast data (from each transmitter) that is used to compile the transmission charge determinants for each rate pool	Yes	Exhibit I, Tab 2, Schedule 1	
37	Determination of the Export Transmission Service rates and the treatment of revenues generated through these rates	N/A		
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 I, Tab 2, Schedule 1 Exhibit I, Tab 3, Schedule 1 Exhibit I, Tab 3, Schedule 1, Attachment 1 Exhibit I, Tab 3, Schedule 1, Attachment 2	

# Distribution System Plan Checklist (as applied to the TSP)

## B2M LP

Filing Requirement  
Page # Reference

Date: July 12, 2018

DISTRIBUTION SYSTEM PLAN REQUIREMENTS		Yes/No/N/A	Evidence Reference, Notes
<b>Ch 5 p7-8</b>	Where applicable, explanation for section headings other than Chapter 5 heading	Yes	
<b>Ch 5 p8-9</b>	(Ch. 5.2.1) 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	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.1
<b>Ch 5 p9-10</b>	(Ch. 5.2.2) 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 p10) and Dx response letter	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.2
<b>Ch 5 p10-12</b>	(Ch. 5.2.3) 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	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 2.3
<b>Ch5 p13</b>	(Ch. 5.3.1.a) Asset Management Process Overview - description of AM objectives/corporate goals and how objectives for prioritizing investments are ranked	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.1
<b>Ch5 p13</b>	(Ch. 5.3.1.b) Inputs/Outputs of the AM process and information flow for investments; flowchart recommended	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.1
<b>Ch 5 p14</b>	(Ch. 5.3.2) 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	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.2
<b>Ch 5 p14-15</b>	(Ch. 5.3.3) 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	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 3.3
<b>Ch 5 p17-18</b>	(Ch. 5.4.1) 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 prioritise REG investments	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.1
<b>Ch 5 p19-20</b>	(Ch. 5.4.2) Capital Expenditure Summary is to provide a snapshot of a distributor's capital expenditures over a 10 year period, including five historical years and five forecast years. Despite the multi-purpose character a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e. initial or trigger) driver of the investment.	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.2
<b>Ch 5 p20</b>	(Ch. 5.4.3) Justifying capital expenditures - Filings must enable the 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.	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.3
<b>Ch 5 p20-21</b>	(Ch. 5.4.3.1) Capital Expenditure Summary by Investment Category - The OEB's assessment of DSPs includes the costs of material projects/programs included in the DSP, as well as how the overall DSP budget is allocated to each of the four investment categories.	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.3
<b>Ch5 p21-28</b>	(Ch. 5.4.3.2) Material Investments - For each project that meets materiality threshold set in Ch 2 p10 - 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)	Yes	Exhibit B, Tab 1, Schedule 3 Attachment 1 Section 4.3





- 1 i. Revenue requirement for 2020 (the “Test year”), determined by using a cost of  
2 service, forward test-year approach;
- 3 ii. Uniform Transmission Rates (“UTR”) for the Network pool for the Test year;
- 4 iii. The proposed Revenue Cap Index mechanism to establish revenue requirement  
5 and UTRs for 2021 to 2024;
- 6 iv. The continuation of B2M LP’s current regulatory accounts;
- 7 v. An accounting order establishing an Earnings Sharing Mechanism Deferral  
8 Account;
- 9 vi. An effective date of January 1, 2020, for the Test year rates;
- 10 vii. Updating the cost of long-term debt in 2021 to reflect the actual long-term debt  
11 rate.

12

13 A number of internal and external challenges will have to be managed over the Test  
14 Period. They include:

- 15 a) Refinancing 100% of B2M LP’s long-term debt that matures in 2020 at market  
16 rates that are higher than its current cost of long-term debt;
- 17 b) Rising income tax expense as B2M LP’s capital cost allowance (“CCA”) declines  
18 and its Ontario corporate minimum tax (“OCMT”) credits are fully depleted; and
- 19 c) Managing B2M LP’s Right-of-Way vegetation maintenance program, taking into  
20 consideration the six-year vegetation cycle and the expected increase in forestry  
21 expenses during certain test years with greater work volumes, similar to the  
22 historical trend.

23

24 B2M LP’s Revenue Cap IR Application, as proposed, will mitigate these challenges,  
25 maintain the Partnership’s financial performance and ensure that B2M LP’s assets are  
26 managed efficiently and effectively.

Witness: Jeffrey Smith

1 The Application will result in a base revenue requirement of \$35.7 million for 2020, a  
2 3.9% increase (\$1.3 million) relative to the OEB-approved 2019 base revenue  
3 requirement.<sup>2</sup> The network UTR increases by \$0.01 to \$3.72 per kW-Month, a 0.3%  
4 increase relative to 2019. The Line Connection and Transformation Connection UTRs are  
5 unaffected.

6  
7 The increase to rates revenue requirement will result in an average impact on  
8 transmission rates of 0.18% and a total bill impact of less than 0.02% (2 cents per month)  
9 for a typical Residential (R1) customer consuming 750 kW per month and, similarly, a  
10 total bill impact of less than 0.01% (4 cents per month) for a typical energy-billed  
11 General Service (GS < 50 kW) customer consuming 2,000 kWh per month. Further  
12 details may be found in Exhibit I, Tab 2, Schedule 1.

13  
14 **3. REVENUE CAP INDEX**

15  
16 The Application is based on a Revenue Cap Index mechanism in which the revenue  
17 requirement for the Test year (2020) is determined by using a cost of service, forward  
18 test-year approach.

19  
20 To establish the annual revenue requirements for 2021 to 2024, a Revenue Cap Index  
21 (“RCI”) is proposed in which the revenue requirement for the Test year t+1 is equal to the  
22 revenue requirement in year t, inflated by the RCI.

23  
24 The RCI is expressed as:

25 
$$RCI = I - X$$

---

<sup>2</sup> EB-2018-0320 2019 OEB approved a base revenue requirement of \$34.4 million. The final rates revenue requirement included a credit for excess revenue earned in 2018 of \$1.6 million for a total of \$32.8 million.

Witness: Jeffrey Smith

1 Where:

- 2 • “I” is the Inflation Factor, based on Hydro One Networks Inc.’s custom weighted  
3 two-factor input price index; and
- 4 • “X” is the Productivity Factor, which includes a Stretch Factor.

5

6 B2M LP proposes to adopt the RCI Inflation Factor (“I”) parameter proposed by Hydro  
7 One Networks Inc. in its current transmission rates proceeding (EB-2019-0082), to be  
8 consistent with the transmission sector. The proposed Inflation Factor is an external  
9 measurement of the transmission industry labour/non-labour weights and would be the  
10 same regardless of the transmission company to which it is being applied.<sup>3</sup>

11

12 The proposed Inflation Factor (“I”) is based on the weighted sum of:

- 13 • 86% of the annual percentage change in Canada’s GDP-IPI (FDD), as reported by  
14 Statistics Canada; and
- 15 • 14% of the annual percentage change in the Average Weekly Earnings for  
16 workers in Ontario, as reported by Statistics Canada.

17

18 The proposed weighting is derived from the analysis conducted by Power Systems  
19 Engineering Inc. (“PSE”) in its study found in EB-2019-0082 at Exhibit A, Tab 4,  
20 Schedule 1. Based on the most recent OEB-reported results, B2M LP has used the  
21 Inflation Factor of 1.4% derived above, on a pro forma basis in its RCI calculation for  
22 each of the 2021 to 2024 Test years, for the purpose of this Application.

23

24 B2M LP proposes a 0% Productivity Factor (“X”) to be applied annually over the 2021 to  
25 2024 period. B2M LP operates under unique circumstances, unlike other transmission  
26 companies in Ontario, when considering its corporate structure, asset holdings, and

---

<sup>3</sup> EB-2018-0218 Hydro One Sault Ste. Marie, Interrogatory I-1-58.

Witness: Jeffrey Smith

1 operating and management arrangements. B2M LP's proposal reflects these  
2 circumstances and is appropriate for the following reasons:

- 3 • B2M LP's assets are new. As such they require lower OM&A in comparison to  
4 other transmitters and no forecast capital expenditures during the rate period;
- 5 • B2M LP's 2020 Test year OM&A is lower than 2015-2019 OEB-approved levels;
- 6 • B2M LP's only controllable costs are OM&A (there are no forecast capital  
7 expenditures) where productivity is normally realized. B2M LP's OM&A costs  
8 are a small fraction of the total costs and are significantly less than the non-  
9 controllable portion of its costs (Cost of Capital, Depreciation, Income Tax),  
10 which are market driven or determined by law. Cost efficiencies determined by  
11 the application of a Productivity and Stretch Factor similar to other transmitters  
12 would be effectively impossible to realize;<sup>4</sup>
- 13 • B2M LP's management and work programs are provided by a service level  
14 agreement, resulting in minimal overhead as well as qualified and flexible  
15 resources when needed, allowing B2M LP to remain cost efficient;
- 16 • B2M LP's service level agreement integrates Hydro One Networks Inc.'s  
17 productivity improvements into B2M LP's maintenance operations; and
- 18 • The B2M LP partnership allows B2M LP to employ a tax structure that provides  
19 rate payers with lower income tax costs compared to other Ontario transmitters.

20  
21 To align B2M LP's business interests with those of ratepayers and provide an additional  
22 element of protection to them, B2M LP is also proposing the following features:

- 23 • An earnings sharing mechanism ("ESM") that will permit ratepayers to share 50%  
24 of earnings that exceed the regulatory ROE by more than 100 basis points in any  
25 year of the Revenue Cap Index term; and

---

<sup>4</sup> In addition, preparing a benchmarking report would yield results of limited utility. The report would require a high degree of customization, including for example the removal of capital costs, facilities, stations and lines (115kV and 230kV) costs, among other things.

Witness: Jeffrey Smith

- 1       • Z-factor and off-ramp mechanisms that apply OEB-approved criteria.  
2

3       **4. B2M LP'S STRATEGIC PLAN**  
4

5       B2M LP's strategic plan on which this Application is based was informed by its values  
6       and strategic objectives described in the section below.  
7

8       B2M LP is sensitive to and has considered the needs of provincial ratepayers that have  
9       expressed a desire for low rates and high reliability (based on customer research  
10       undertaken by other transmitters e.g. Hydro One Networks Inc.). B2M LP's plan supports  
11       these general customer objectives by proposing no planned capital spending and a  
12       minimal OM&A budget required to maintain B2M LP's transmission reliability.  
13

14       B2M LP's Strategic Plan may be found at Exhibit B-1-2.  
15

16       **4.1 B2M LP'S VALUES AND STRATEGIC OBJECTIVES**  
17

18       B2M LP, as part of the Hydro One family of companies, is driven primarily by the values  
19       of health and safety, and stewardship. B2M LP's strategy and business values must  
20       operate with rates that can balance the financing of investment in infrastructure while  
21       maintaining affordable and reliable service.  
22

23       B2M LP is 34% owned by a partnership of First Nations over whose traditional territory  
24       the transmission line crosses. Respect for Indigenous peoples and their traditions is  
25       another key value of the partnership.

26       B2M LP's business is underpinned and driven by its strategic objectives. These  
27       objectives consist of the following:

Witness: Jeffrey Smith

- 1 • Oversee a service level agreement with Hydro One Networks Inc. that supports
- 2 creating an injury-free workplace and maintaining public safety;
- 3 • Foster relationships with the owners of the partnership and the Indigenous
- 4 communities;
- 5 • Maintain a reliable, cost-effective transmission system;
- 6 • Protect and sustain the environment for future generations;
- 7 • Maintain a commercial culture that increases value for its owners; and
- 8 • Achieve productivity improvements and cost effectiveness.

9

10 The five-year vision associated with B2M LP’s strategic objectives is shown in Table 1.

11 In managing its transmission assets, B2M LP is committed to meeting the OEB’s

12 Renewed Regulatory Framework (“RRF”) outcomes as demonstrated by the alignment of

13 B2M LP’s strategic objectives to the RRF outcomes.

14

15 **Table 1 - B2M LP Strategic Objectives**

<b>RRF Outcomes</b>	<b>Strategic Objectives</b>	<b>Five-Year Vision</b>
Customer Focus	Foster Indigenous Relationships	Continue to maintain effective and beneficial relationships.
Operational Effectiveness	Injury-Free	Ensure B2M LP’s operations and management services agreement is executed in accordance with good utility practice for employee and public safety.
	Reliable Transmission	Continue to maintain a reliable transmission system.
	Cost Control	Strive to minimize costs and pass on savings to the customers of the province.
Public Policy Responsiveness	Protecting the Environment	Sustainably manage B2M LP’s environmental footprint.
Financial Performance	Owner’s Value	Achieve the Regulated Return On Equity allowed by the Ontario Energy Board.

Witness: Jeffrey Smith

1 **5. KEY ELEMENTS OF THE APPLICATION**

2  
3 **5.1 REVENUE REQUIREMENT**

4  
5 B2M LP's 2020 revenue requirement is shown in Table 2. The revenue requirement in  
6 subsequent years of the Test period will be determined using the RCI, which is described  
7 in Exhibit A, Tab 4, Schedule 1.  
8

9 **Table 2 - Revenue Requirement (\$ Millions)**

Components	2019 <sup>1</sup>	2020	Reference
OM&A	1.5	1.2	Exhibit F, Tab 1, Schedule 1
Depreciation	6.8	7.0	Exhibit F, Tab 5, Schedule 1
Income Taxes	0.8	1.0	Exhibit F, Tab 6, Schedule 1, Attachment 1
Return on Capital	23.4	26.6	Exhibit G, Tab 1, Schedule 1
Start-Up and Development Costs Recovery	1.9	0.0	Exhibit F, Tab 1, Schedule 1
<b>Base Revenue Requirement</b>	<b>34.4</b>	<b>35.7</b>	
Deduct External Revenues and Other <sup>5</sup>	(1.6)	(0.1)	Exhibit H, Tab 1, Schedule 1
<b>Rates Revenue Requirement</b>	<b>32.8</b>	<b>35.7</b>	

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

11  
12 The drivers of the increase in the 2020 base revenue requirement compared the 2019  
13 OEB-approved base revenue requirement are summarized by component in Table 3. The  
14 increase in base revenue requirement by \$1.3 million is driven predominantly by higher  
15 cost of debt, which is partially offset by the elimination of start-up and development  
16 costs.

---

<sup>5</sup> B2M LP had a one-time over collection of revenue in 2018 of \$1.6 million. This was refunded in 2019.

Witness: Jeffrey Smith

**Table 3 - Changes to Individual Components of Base Rates Revenue Requirement  
 Since Most Recent Rebasing**

Description	2020 vs. 2019 (\$ millions)	2020 vs. 2019 (%)
OM&A	(0.3)	-1.0%
Rate Base	(0.1)	-0.3%
Cost of debt	3.6	10.4%
Tax	0.2	0.5%
Start-Up and Development Costs Recovery	(1.9)	-5.6%
<b>Impact on Base Revenue Requirement</b>	<b>1.3</b>	<b>3.9%</b>

*Exhibit Reference: E-1-1, Table 6*

The proposed Revenue Cap IR Application would result in the base revenue requirement over the Test period as shown in Table 4.

**Table 4 - Base Revenue Requirement by Year**

Year	Formula	Base Revenue Requirement
2020	Cost of Service	\$ 35.7 million
2021	2020 Base Revenue Requirement** x 1.014*	\$ 36.2 million
2022	2021 Base Revenue Requirement x 1.014*	\$ 36.7 million
2023	2022 Base Revenue Requirement x 1.014*	\$ 37.3 million
2024	2023 Base Revenue Requirement x 1.014*	\$ 37.8 million

\* Calculations assume RCI in Exhibit A, Tab 4, Schedule 1 Table 2

\*\* Exhibit E, Tab 1, Schedule 1, Table 1: To be updated to reflect the actual market rate of the cost of long-term debt after debt refinancing has been completed.

Exhibit A, 4, 1 Table 2

## 5.2 BUDGETING ASSUMPTIONS

B2M LP has included no future capital expenditures. Therefore, assumptions regarding inflation and exchange rates have not been provided.

Witness: Jeffrey Smith

1 **5.3 LOAD FORECAST**

2  
3 B2M LP has included no load forecast, as it has no distinct metering points or delivery  
4 points. All power transported using B2M LP's assets are delivered to the final customer  
5 by another transmitter and thus is included in another transmitter's load forecast. The  
6 revenue requirement is allocated to the provincial Network rate pool, as all assets serve  
7 the Network with no Transformation or individual customer services. Once the revenue  
8 requirement by rate pool has been established, rates are determined by applying the  
9 Provincial charge determinants for each pool to the total revenue for each pool.

10  
11 **5.4 TRANSMISSION SYSTEM PLAN**

12  
13 This section summarizes the major drivers and elements of B2M LP's five-year TSP  
14 (Exhibit B, Tab 1, Schedule 1, Attachment 1). B2M LP has aligned its TSP in accordance  
15 with Chapter 2 of the Ontario Energy Board's ("OEB") *Filing Requirements for*  
16 *Electricity Transmission Applications* published on February 11, 2016, with further  
17 guidance from Chapter 3 and 5 of the OEB's *Filing Requirements (Incentive Regulation*  
18 *and Consolidated Distribution System Plan Filing Requirements)*, revised on July 12,  
19 2018 (together, the "Filing Requirements").

20  
21 **5.4.1 ASSET MANAGEMENT PROCESS**

22 B2M LP continues to retain Hydro One Networks Inc. under a service level agreement to  
23 plan and organize the operation and maintenance of the assets and provide certain  
24 corporate and administrative support services. B2M LP relies upon Hydro One Networks  
25 Inc.'s asset management process to develop its Plan. Hydro One Networks Inc. has  
26 continued to implement several refinements in its asset strategies and investment  
27 assessment to improve upon its asset management process, as documented in Exhibit B,  
28 Tab 1, Schedule 1 of Proceeding EB-2019-0082. Given the lack of required capital

Witness: Jeffrey Smith

1 spending, those changes are not meaningful in this application but will potentially benefit  
2 B2M LP in a future period.

3

#### 4 **5.4.2 INVESTMENT PLANNING PROCESS**

5 B2M LP's operational needs are assessed by Hydro One Networks Inc. on an annual  
6 basis and are incorporated into Hydro One Networks Inc.'s investment planning process  
7 to establish a plan that addresses those operation needs while minimizing rate impacts.  
8 This planning process ultimately forms part of the overall asset management process,  
9 which is aimed at identifying and scoping the optimal timing of capital investments and  
10 asset maintenance throughout the life cycle of assets.

11

#### 12 **5.4.3 CAPITAL EXPENDITURES**

13 B2M LP's transmission assets are limited to the components of a single 500kV double  
14 circuit transmission line. Given the relatively new vintage of this line, no planned capital  
15 spending is required to meet the Applicant's business objectives over the 2020 to 2024  
16 planning period. The absence of capital spending will result in no in-service additions to  
17 grow its rate base during the planning period. Table 5 below summarizes B2M LP's  
18 planned capital expenditures by category over the TSP planning period.

1

**Table 5 - Overall Plan (\$Millions)**

OEB Category	2019			2020	2021	2022	2023	2024
	Plan	Frcst	Var	Test	Test	Test	Test	Test
System Access	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Renewal	0.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0
System Service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total Capital</b>	<b>0.0</b>	<b>3.0</b>	<b>3.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>
<b>System OM&amp;A</b>	<b>0.8</b>	<b>0.7</b>	<b>-0.1</b>	<b>0.7</b>	*	*	*	*

2 \*System OM&A includes Operations, Maintenance and Administration expenses related to B2M LP's Service Level  
 3 Agreement with Hydro One. System OM&A for 2021 to 2024 is determined based on the escalation factor identified in  
 4 Exhibit A, Tab 4, Schedule 1  
 5 Exhibit Reference – B-1-4 Attachment 1 Table 5  
 6

7 The majority of B2M LP's assets were placed into service in 2012. Therefore, little  
 8 degradation has occurred, and these assets are considered to have a low condition risk.  
 9 However, there is a population of insulators on the older section of line that B2M LP  
 10 owns because it allowed the new line to be diverted around a specific property. The  
 11 insulators on the older section of line are defective and, due to their condition, are high  
 12 risk.

13  
 14 This insulator defect is related to the porcelain insulators manufactured by Canadian Ohio  
 15 Brass ("COB") and Canadian Porcelain ("CP") between 1965 and 1982 that suffer from a  
 16 phenomenon known as cement expansion or cement growth. Insulators suffering from  
 17 cement expansion are expected to fail prematurely and unpredictably. This topic is  
 18 discussed extensively in Hydro One's Transmission Rate Application (EB-2019-0082) in  
 19 Exhibit B, Tab 1, Schedule 1, TSP Section 2.2.2.4.

20  
 21 The defective insulators on the small, older portion of B2M LP's line were identified in  
 22 early 2019 and will be repaired in late 2019 as shown in Table 5 above.

Witness: Jeffrey Smith

1 **5.5 RATE BASE**

2  
 3 The requested rate base over the Test period is provided in Table 6 below. Details are  
 4 provided in Exhibit C, Tab 1, Schedule 1. The 2020 rate base represents a \$5.6 million  
 5 (1.1%) decrease over 2019 OEB-approved levels.  
 6

7 **Table 6 - Transmission Rate Base (\$ Millions)**

Description	Bridge OEB Approved**	Test*
	2019	2020
Mid-Year Gross Plant	549.2	550.7
Mid-Year Accumulated Depreciation	(53.7)	(60.8)
<b>Mid-Year Net Plant</b>	495.5	489.9
Cash Working Capital	0.0	0.0
Materials and Supply Inventory	0.0	0.0
<b>Transmission Rate Base</b>	495.5	489.9

8 \* Exhibit Reference: C-1-1, Table 1

9 \*\* EB-2018-0320 B2M LP DRO 2019 OEB-Approved

10  
 11 **5.6 PERFORMANCE AND REPORTING**

12  
 13 B2M LP is proposing to continue to track performance by utilizing most of the measures  
 14 approved by the OEB in proceeding EB-2015-0026 to ensure B2M LP is meeting its five-  
 15 year plan as described in this Application. The performance measures, along with their  
 16 associated RRF performance outcomes, are shown in Table 7.  
 17

18 **Table 7 - B2M LP's Performance Measures**

RRF Outcomes	Performance Measure
Operational Excellence	Average System Availability (%)
Public Policy Responsiveness	NERC Vegetation Compliance
Operational Excellence	OM&A Cost (\$K) per circuit kilometre
Financial Performance	Return on Equity (%)

Witness: Jeffrey Smith

1 Given the nature of B2M LP's assets, the performance of the equipment does not lend  
2 itself to applying the typical measures that might be in place for other transmitters. B2M  
3 LP's assets consist solely of a 500kV double circuit transmission line and do not include  
4 any terminal breakers or other operable assets, as the demarcation point of each of the  
5 circuits is at a tower outside of the station as noted in Exhibit B, Tab 1, Schedule 1. B2M  
6 LP does not have any customer delivery points (or meter assets), which are the basis of  
7 reliability performance measures. In addition to these operating characteristics, the life-  
8 cycle of B2M LP's assets detracts from meaningful comparisons.

9  
10 Therefore, B2M LP's performance measures do not readily provide meaningful  
11 comparisons to other transmitters. On this basis, B2M LP proposes that System Average  
12 Interruption Frequency and System Average Interruption Duration no longer be  
13 monitored. Furthermore, B2M LP has no customers; therefore, no Customer Focus  
14 measures have been proposed.

15  
16 Further details on the methods and measures as well as the historical performance and  
17 forecast targets are documented in Exhibit D, Tab 1, Schedule 1.

18  
19 **5.7 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A)**  
20 **EXPENSE**

21  
22 B2M LP will be managed by its general partner, Hydro One Indigenous Partnerships GP  
23 Inc. ("HOIP"), formerly named B2M GP Inc., which will retain Hydro One Networks  
24 Inc. ("HONI"), under a Service Level Agreement, to plan and organize the operation and  
25 maintenance of the assets and provide certain corporate and administrative support  
26 services as outlined in Exhibit F, Tab 3, Schedule 1.

Witness: Jeffrey Smith

1 OM&A expenses are derived based upon the various work programs and functions  
 2 performed by or on behalf of the Partnership. The estimated total OM&A expense is  
 3 \$1.2 million in 2020. Further details on the OM&A costs are provided in Exhibit F, Tab  
 4 2, Schedule 1 and presented in Table 8 below.

5  
 6

**Table 8 - Summary of OM&A (\$ Millions)\***

Description	Historical								Bridge		Test
	2015		2016		2017		2018		2019		2020
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Service Level Agreement Costs	0.9	0.7	0.8	0.8	0.8	1.0	2.0	1.1	0.8	0.7	0.7
Incremental Expenses	0.9	0.4	0.4	0.3	0.5	0.3	0.4	0.3	0.7	0.7	0.4
<b>Total OM&amp;A</b>	1.8	1.1	1.2	1.1	1.2	1.3	2.4	1.4	1.5	1.3	1.2

7 \* Exhibit F-2-1 Table 1, 2015-2016 include reductions due to the EB-2014-0140 Decision and 2018 – 2019 include the  
 8 reductions due to the EB-2015-0026 Decision.

9

10 The proposed OM&A spending for the 2020 Test Year is forecast to be \$1.2 million,  
 11 consistent with the average annual spend over the historical years and reflects lower  
 12 spending relative to its historical 2015-2019 OEB-approved levels based on experience  
 13 operating its business since its inception. The 2020 Test Year forecast represents a  
 14 decrease of \$0.2 million over the 2019 Bridge Year forecast. This decrease is entirely  
 15 related to the forecast Regulatory expenses in 2019 related to this Application. All other  
 16 OM&A components are substantially unchanged in the Test Year compared to the Bridge  
 17 Year forecast.

18

19 Over the 2015 to 2019 period, the OM&A spending has generally been on plan. The two  
 20 exceptions are:

- 21 (i) 2015, which saw spending below plan by about \$0.7 million, resulting from  
 22 lower than anticipated Operating Services costs and lower than anticipated

Witness: Jeffrey Smith

1 Incremental expenses (including Regulatory and Advisory Committee  
2 expenses) as discussed below; and  
3 (ii) 2018, which saw spending below plan by about \$1.0 million, due mainly to  
4 variances in the Service Level Agreement costs.  
5

## 6 **5.8 COST OF CAPITAL**

7  
8 Table 9 below summarizes the return on capital for the 2020 Test year.  
9

10 **Table 9 - 2020 Cost of Capital**

<b>2020</b>				
<b>Amount of Deemed Return</b>	<b>(\$M)</b>	<b>%</b>	<b>Cost Rate (%)</b>	<b>Return (\$M)</b>
Long-term debt	274.3	56%	3.08%	8.4
Short-term debt	19.6	4%	2.82%	0.6
Common equity	196.0	60%	8.98%	17.6
<b>Total</b>	<b>489.9</b>	<b>100%</b>	<b>5.43%</b>	<b>26.6</b>

11 *Exhibit Reference: G-1-1*

12  
13 B2M LP's deemed capital structure for rate-making purposes is 60% debt and 40%  
14 common equity of utility rate base, as affirmed by the OEB's Decision in B2M LP's 2015  
15 to 2019 transmission rate application (EB-2015-0026). The 60% debt component is  
16 comprised of 4% deemed short-term debt and 56% long-term debt.<sup>6</sup>  
17

18 B2M LP will update the revenue requirement for the 2020 Test Year when the OEB  
19 releases its 2020 cost of capital parameters to reflect: (a) the OEB-approved 2020 return  
20 on equity and short-term debt rates; and (b) a long-term debt rate based on B2M LP's  
21 weighted average of its existing debt rate and the rate on B2M LP's forecast debt

---

<sup>6</sup> Consistent with the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016.

Witness: Jeffrey Smith

1 refinancing in 2020, using the September 2019 Consensus Forecast. B2M LP proposes  
2 that the 2020 cost of capital parameters established at that time be used to determine the  
3 final revenue requirements for the 2020 Test year.

4  
5 In 2015 B2M LP was able to issue debt at historically low rates that provided millions of  
6 dollars of savings to ratepayers. However, unlike other transmission companies such as  
7 Hydro One Networks Inc. Transmission, which have capital structures that include a  
8 portfolio of embedded debt with maturities ranging from less than one year to more than  
9 40 years, the entire amount of B2M LP's debt matures all at once in April 2020.

10  
11 B2M LP anticipates that the OEB will issue its Decision and Order in this proceeding  
12 prior to B2M LP issuing new debt to refinance its maturing long-term debt in 2020. The  
13 future refinancing rate on 100% of B2M LP's long-term debt is unknown and could have  
14 a material impact on B2M LP's financial performance if the actual cost is not reflected in  
15 rates. B2M LP proposes a one-time update to the cost of long-term debt at the first  
16 annual update for rates in 2021, to reflect the actual market rate achieved on the long-  
17 term debt it will issue. Based on the current forecast rates, the cost of debt for 2021  
18 would be 3.63%. In the alternative, if approval to update the long-term debt at the first  
19 annual update for rates in 2021 is not granted, B2M LP proposes to apply the forecast  
20 rate of 3.63% for new long-term debt beginning in 2020 to determine the cost of debt  
21 during the five-year period.

22  
23 Further details regarding the cost of capital can be found in Exhibit G, Tab 1, Schedule 1.

## 24 25 **5.9 COST ALLOCATION AND RATE DESIGN**

26  
27 All assets associated with B2M LP are classified as Network assets, consistent with the  
28 cost allocation methodology approved by the Board for B2M LP in proceeding EB-2015-

Witness: Jeffrey Smith

1 0026. Accordingly, all of the rates revenue requirement associated with B2M LP's  
2 transmission assets will be allocated to the Network pool. Further details regarding the  
3 cost allocation and rate design can be found in Exhibit I, Tab 1, Schedule 1.

4  
5 **5.10 DEFERRAL AND VARIANCE ACCOUNTS**

6  
7 There is a small 2019 forecast balance for regulatory accounts in the amount of  
8 (\$55,379). As such, B2M LP is requesting to adjust its revenue requirement over a one-  
9 year period commencing January 1, 2020. B2M LP's outstanding regulatory account  
10 balances are summarized in Table 10 below:

11  
12 **Table 10 - Summary of Regulatory Account Balances (\$ Million)**

<b>Description</b>	<b>US of A Account Ref.</b>	<b>Balance as at Dec. 31, 2019 (Forecast)</b>
Forgone Revenue Deferral Account	1508	(0.1)
Tax Rate and Rule Changes Variance Account	1592	0.0
<b>Total Regulatory Accounts</b>		<b>(0.1)</b>

13  
14 B2M LP is requesting approval to continue all existing accounts and to establish an  
15 Earnings Sharing Mechanism (ESM) Deferral Account, as detailed in Exhibit H, Tab 1,  
16 Schedule 1. The ESM Deferral Account would record and share with customers 50% of  
17 any over-earnings that exceed the OEB-allowed regulatory ROE by more than 100 basis  
18 points realized during any year of the Test period.

Witness: Jeffrey Smith

1 **5.11 BILL IMPACTS**

2  
 3 Exhibit I, Tab 2, Schedule 1 provides the bill impacts that would result from approval of  
 4 the Application, along with illustrative bill impacts for 2021 - 2024. Table 11 shows the  
 5 average 2020 bill impacts of the proposed changes in transmission rates revenue  
 6 requirement and load forecast.

7  
 8 **Table 11 - Average Bill Impacts on Transmission and**  
 9 **Distribution-connected Customers**

	<b>2019*</b>	<b>2020</b>
Rates Revenue Requirement (\$Millions)	32.8	35.7
% Increase in Rates Revenue Requirement over prior year		8.8%
% Impact of load forecast change		0.0%
B2M LP Rates Revenue Requirement as a % of All Transmitters	2.0%	
<b>Net Impact on Average Transmission Rates</b>		0.18%
Transmission as a % of Tx-connected customer's Total Bill		7.4%
<b>Estimated Average Bill impact</b>		0.01%
Transmission as a % of Dx-connected customer's Total Bill		6.2%
<b>Estimated Average Bill impact</b>		0.01%

10 \*2019 rates revenue requirement as per the OEB's Decision and Order for B2M LP's Transmission Revenue  
 11 Requirement application (EB-2018-0320, Schedule A, Exhibit 1.0), issued on 20<sup>th</sup> December, 2018.

12  
 13 The 8.8% increase in rates revenue requirement is driven predominantly by higher cost of  
 14 debt and a reduction in regulatory deferral account disposition (2019 revenue requirement  
 15 included a credit related to excess 2018 revenue), which is partially offset by the  
 16 elimination of start-up and development costs.

17  
 18 The total bill impact for a typical Hydro One Networks Inc. medium density residential  
 19 (R1) customer consuming 750 kWh, and for a typical and General Service (GSe)  
 20 customer consuming 2,000 kWh/month is determined based on the forecast increase in

Witness: Jeffrey Smith

1 the customer’s Retail Transmission Service Rates (“RTSR”) as detailed below in Table  
 2 12 below.

3  
 4

**Table 12 - Typical Medium Density (R1) Residential Customer Bill Impacts**

	<b>Typical Medium Density (HONI R1) Residential Customer 750 kWh</b>	<b>Typical General Service Energy less than 50 kW (HONI GSe &lt; 50kW) Customer 2,000 kWh</b>
Total Bill as of May 1, 2018 <sup>1</sup>	\$124.30	\$389.14
RTSR included in R1 Customer's Bill (based on 2019 Interim UTR)	\$11.94	\$25.21
<i>Estimated 2020 Monthly RTSR<sup>2</sup></i>	\$11.96	\$25.25
<b>2020 increase in Monthly Bill</b>	<b>\$0.02</b>	<b>\$0.04</b>
<i>2020 increase as a % of total bill</i>	<i>0.02%</i>	<i>0.01%</i>

<sup>1</sup>Total bill including HST, based on time-of-use commodity prices and distribution rates effective May 1, 2018 approved per Distribution Rate Order EB-2017-0049 (includes impacts of all applicable components of the Fair Hydro Plan).

<sup>2</sup>The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2 (in I-2-1), adjusted for B2M LP's revenue disbursement allocator, as per the interim 2019 UTR Order (EB-2018-0326) issued on December 20, 2018.

5  
 6

**6. CONCLUSION**

7

8 B2M LP’s Application balances the needs of its system and assets and allows it to  
 9 operate and maintain these assets in accordance with reliability standards and satisfy  
 10 regulatory, environmental, and legal requirements.

11

12 B2M LP operates under unique circumstances, unlike those of any other transmission  
 13 company in Ontario, when considering its corporate structure, asset holdings, and  
 14 operating and management arrangements. In consideration of these unique circumstances,  
 15 B2M LP has made every effort to align its Application with the OEB’s expectations  
 16 under the RRF.

Witness: Jeffrey Smith

1 Over the five-year term, B2M LP will need to manage a number of internal and external  
2 factors that will put pressure on its financial performance. However, this Application, as  
3 proposed, will mitigate these challenges, maintain the Partnership's financial  
4 performance and ensure that B2M LP's assets are managed effectively.



1 **1.1 INFLATION FACTOR**

2  
3 B2M LP proposes to adopt the RCI Inflation Factor (“I”) parameter proposed by Hydro  
4 One Networks Inc. in its current transmission rates proceeding (EB-2019-0082), to be  
5 consistent with the transmission sector. The proposed Inflation Factor is an external  
6 measurement of the transmission industry labour/non-labour weights and would be the  
7 same regardless of the transmission company to which it is being applied.<sup>1</sup>

8  
9 The proposed Inflation Factor (“I”) is based on the weighted sum of:

- 10 • 86% of the annual percentage change in Canada’s GDP-IPI (FDD) as reported by  
11 Statistics Canada; and
- 12 • 14% of the annual percentage change in the Average Weekly Earnings for  
13 workers in Ontario, as reported by Statistics Canada.

14  
15 The proposed weighting of 14% labour and 86% non-labour is derived from the analysis  
16 conducted by Power Systems Engineering Inc. (“PSE”) in its study found in EB-2019-  
17 0082 at Exhibit A, Tab 4, Schedule 1, Attachment 1.

18  
19 The latest annual percent change for the GDP-IPI and the Average Weekly Earnings for  
20 Workers in Ontario was released by the OEB on November 23, 2018, for use in  
21 applications for rates effective in 2019. The derivation of B2M LP’s proposed Inflation  
22 Factor is shown in Table 1 below.

---

<sup>1</sup> EB-2018-0218 Hydro One Sault Ste. Marie, Interrogatory I-1-58.

1

**Table 1 - Derivation of Inflation Factor**

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

2

3

4 B2M LP has used the Inflation Factor of 1.4% derived above, on a pro forma basis in its  
 5 RCI calculation for each of the 2021 to 2024 test years, for the purpose of this  
 6 Application.

7

8 The Inflation Factor will be updated annually based on the methodology above to reflect  
 9 the actual annual percent changes for each index that are made available by the OEB  
 10 when it sets the Inflation Factor for distributors in each of 2020, 2021, 2022 and 2023,  
 11 effective 2021, 2022, 2023 and 2024, respectively.

12

13 **1.2 PRODUCTIVITY FACTOR**

14

15 B2M LP has considered the OEB’s expectation for the development of a Revenue Cap  
 16 “index, as well as productivity and stretch commitments.”<sup>2</sup> However, given B2M LP’s  
 17 unique circumstances, the Company proposes a 0% Productivity Factor (“X”) and that  
 18 the factor not be updated annually over the 2021 to 2024 period.

19 B2M LP operates under unique circumstances unlike those of any other transmission  
 20 company in Ontario, when considering its corporate structure, asset holdings, and

---

<sup>2</sup> OEB Filing Requirements for Electricity Transmission Applications Chapter 2, February 11, 2016, p 1.

Witness: Kathleen Burke

1 operating and management arrangements. B2M LP's proposal is appropriate for the  
2 following reasons:

- 3 • B2M LP owns and operates a single 500kV transmission line that currently has an  
4 average age of 10 years, compared to an expected service life of greater than 80  
5 years. These assets are new and require lower OM&A in comparison to other  
6 transmitters, and no forecast capital expenditures during the rate period;
- 7 • B2M LP's 2020 Test year OM&A reflects lower spending relative to its 2015-  
8 2019 OEB-approved levels;
- 9 • B2M LP's main controllable cost is OM&A (there are no forecast capital  
10 expenditures). These costs are a small fraction of total costs and are significantly  
11 less than the non-controllable portions of B2M LP's costs (Cost of Capital,  
12 Depreciation, Income Tax). Therefore, cost efficiencies are available only in  
13 respect of the modest portion of OM&A costs;<sup>3</sup>
- 14 • B2M LP's management and work programs are provided by a service level  
15 agreement, resulting in minimal overhead as well as qualified and flexible  
16 resources when needed, allowing B2M LP to remain cost efficient; and
- 17 • B2M LP's service level agreement integrates Hydro One Networks Inc.'s  
18 productivity improvements into B2M LP's maintenance operations.

19  
20 **1.3 REVENUE CAP INDEX SUMMARY**

21  
22 Table 2 below summarizes the RCI by component that B2M LP is proposing to use to  
23 determine the total revenue requirement for rate-making purposes for 2021 through 2024.

---

<sup>3</sup> In addition, preparing a benchmarking report would yield results of limited utility. The report would require a high degree of customization, including for example the removal of capital costs, facilities, stations and lines (115kV and 230kV) costs, among other things.

Witness: Kathleen Burke

**Table 2 - Revenue Cap Index (RCI) by Component (%)**

<b>Revenue Cap Index by Component</b>	<b>2021</b>	<b>2022</b>	<b>2023</b>	<b>2024</b>
Inflation Factor (I)	1.4%	1.4%	1.4%	1.4%
Productivity Factor (X)	0.0%	0.0%	0.0%	0.0%
<b>Total Revenue Cap Index</b>	1.4%	1.4%	1.4%	1.4%

The Inflation Factor in Table 2 will be updated annually, as described in section 1.1 of this Exhibit. B2M LP proposes that the Productivity Factor will remain unchanged throughout the IR term. Table 3 below summarizes the Total Revenue Requirement that would result, were the Application to be approved as filed.

**Table 3 - Revenue Requirement by Year**

<b>Year</b>	<b>Formula</b>	<b>Revenue Requirement</b>
2020	Cost of Service	\$ 35.7 million
2021	2020 Base Revenue Requirement** x 1.014*	\$ 36.2 million
2022	2021 Base Revenue Requirement x 1.014*	\$ 36.7 million
2023	2022 Base Revenue Requirement x 1.014*	\$ 37.3 million
2024	2023 Base Revenue Requirement x 1.014*	\$ 37.8 million

\* Calculations assume the RCI in Table 2.

\*\* Exhibit E, Tab 1, Schedule 1, Table 1: To be updated reflecting the actual market rate of the cost of long-term debt after debt refinancing has been completed.

## **1.4 ADDITIONAL IR FEATURES**

B2M LP is proposing the following additional features in this Application to align its interests with those of customers and to provide an additional element of protection for customers.

### **1.4.1 EARNINGS SHARING MECHANISM (ESM)**

B2M LP 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 Revenue Cap IR term. The customer share of the earnings will be adjusted for any tax impacts and will

Witness: Kathleen Burke

1 be credited to a new deferral account for clearance at the time of B2M LP's next  
2 rebasing. The calculation of the actual ROE for a Test year will use the OEB-approved  
3 mid-year rate base for that period.

#### 5 **1.4.2 Z-FACTOR**

6 B2M LP is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism  
7 be available over the term of this Revenue Cap IR Application. This is consistent with  
8 the principles of the RRF. The criteria that would apply to the use of the Z-factor  
9 mechanism are those outlined by the OEB in Chapter 2 of the Filing Requirements for  
10 Electricity Transmission Applications and the guidelines provided in section 2.6 of the  
11 OEB's Report on 3<sup>rd</sup> Generation Incentive Regulation for Ontario's Electricity  
12 Distributors (July 14, 2008).

13  
14 Events that may necessitate the use of the Z-factor mechanism include:

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

#### 24 25 **1.4.3 OFF-RAMPS**

26 B2M LP proposes to apply the OEB's existing policy with respect to off-ramps. The  
27 Handbook states that although the purpose of incentive regulation is to drive productivity  
28 improvements within the utility, customers must also be protected from utility earnings

Witness: Kathleen Burke

1 that become excessive. B2M LP is therefore proposing to adopt the OEB's existing off-  
2 ramp mechanism, a trigger mechanism with an annual return on equity dead band of plus  
3 or minus 300 basis points, at which point a regulatory review of the Revenue  
4 Requirement arising from B2M LP's IR may be initiated.

5  
6 **2. PROPOSED FRAMEWORK FOR ANNUAL UPDATE APPLICATIONS**

7  
8 B2M LP expects to file annual update applications in 2021, 2022, 2023 and 2024. These  
9 applications are expected to be filed by the deadline for electricity distribution IRM  
10 applications seeking a January 1<sup>st</sup> effective date, which has typically been near the end of  
11 August. These applications would calculate the revenue requirement by using the RCI to  
12 reflect the most up to date Inflation Factor, as described in section 1.1 and provide  
13 revised Uniform Transmission Rate calculations that reflect the revised revenue  
14 requirement.

15  
16 As described above, B2M LP proposes that the application in 2021 would also update the  
17 cost of long-term debt to reflect the market rate associated with B2M LP's new debt  
18 instrument(s).

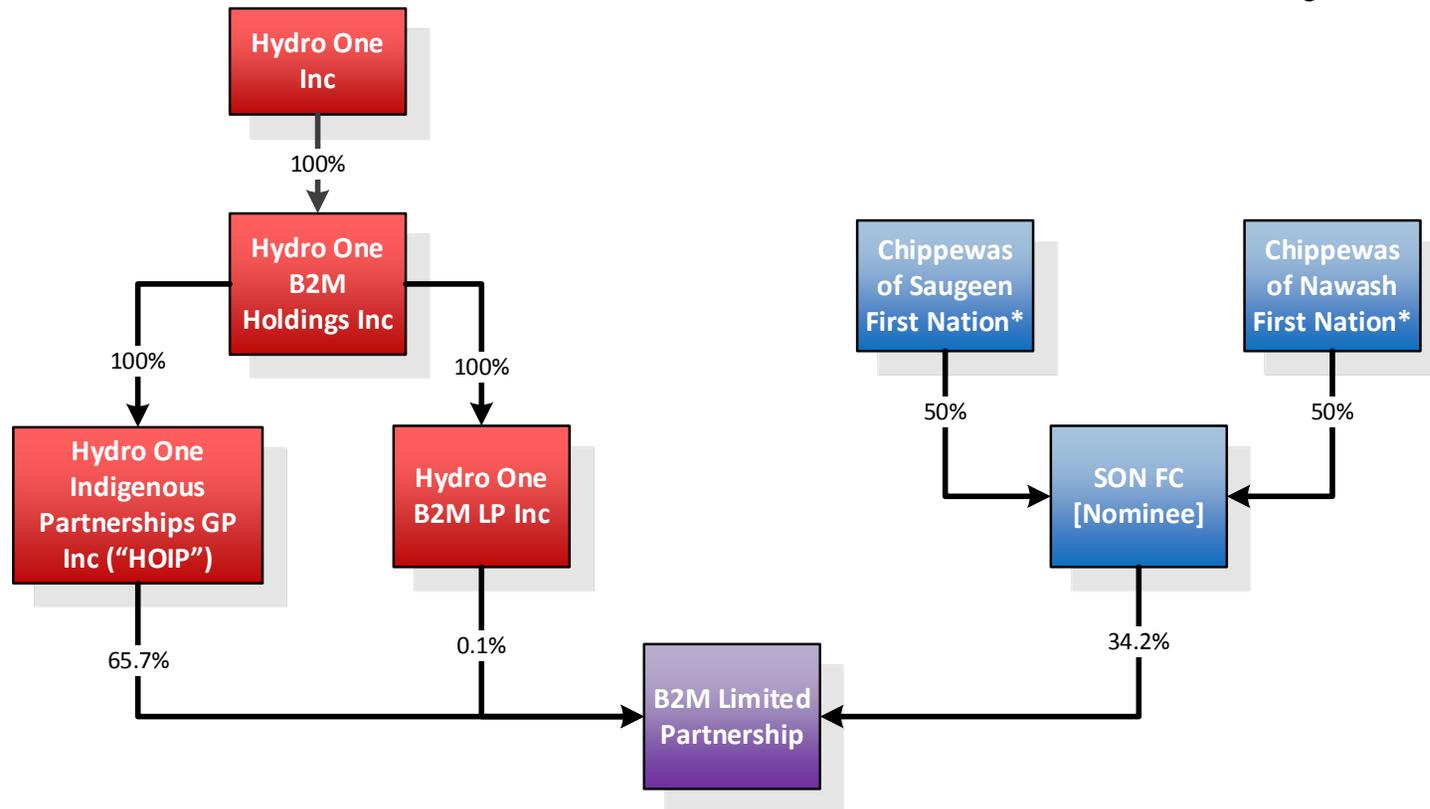
19  
20 In the event that deferral and variance account balances accumulated in subsequent years  
21 are material, B2M LP may also seek to dispose of any balances in its annual update  
22 applications.



1 to be the vehicle for SON to participate in the ownership of B2M LP. SON FC holds the  
2 partnership interest in B2M LP for SON but has no other substantial assets or liabilities  
3 other than the financing arranged to fund the acquisition cost of its partnership interest.  
4 SON FC will receive its share of the net profit from B2M LP without incurring income  
5 taxes. The resulting reduction in income taxes serves to decrease the cost of B2M LP's  
6 assets to ratepayers over their life.

7

8 The organization chart for the B2M LP shareholder structure and financial ownership  
9 structure is found below.



\* a Band within the meaning of Section 2(1) of the *Indian Act* (Canada)

**Figure 1 - Organization Chart for the B2M LP Shareholder Structure**

Witness: Jeffrey Smith, Derek Chum

1 **FINANCIAL INFORMATION**

2  
3 **1. ACCOUNTING STANDARD**

4  
5 B2M LP applies United States Generally Accepted Accounting Principles (“US GAAP”)  
6 for regulatory purposes in its transmission business.

7  
8 **2. CHANGES TO ACCOUNTING POLICIES**

9  
10 In keeping with good corporate governance, B2M LP reviews and, if appropriate, revises  
11 its policies and procedures from time to time. No accounting policy changes have been  
12 made that impact the 2020-2024 rate base or revenue requirements since the OEB’s  
13 review of B2M LP’s transmission revenue requirements and rates for 2015-2019 (EB-  
14 2015-0026).

15  
16 **3. ACCOUNTING ORDERS**

17  
18 With respect to the deferral accounts described in Exhibit H, Tab 1, Schedule 1, the  
19 following accounts were created subsequent to the OEB’s review of B2M LP’s  
20 transmission deferral accounts in EB-2015-0026:

21  
22 **3.1 FOREGONE TRANSMISSION REVENUE DEFERRAL ACCOUNT (EB-  
23 2016-0349)**

24  
25 B2M LP filed an accounting order with the OEB on June 15, 2017, pursuant to the OEB’s  
26 decision on B2M LP’s transmission revenue requirement effective January 1, 2017,  
27 which established the deferral account for the purpose of recording the differences  
28 between revenue earned by B2M LP under the interim 2017 rates set at the 2016 Uniform

Witness: Samir Chhelavda

1 Transmission Rates (UTR) level, and the revenues that would have been received under  
2 the approved 2017 UTR. The accounting order was approved on June 29, 2017.

3

4 Pursuant to the OEB's Decision in EB-2017-0380, B2M LP recorded excess 2018  
5 revenue resulting from the interim 2018 B2M LP revenue requirement amount included  
6 in the 2018 UTR being more than the amount approved by the OEB in the proceeding,  
7 into this account.

1           **B2M LP FINANCIAL STATEMENTS - HISTORICAL YEARS**

2

3           Included in this exhibit are the Historical Transmission Financial Statements:

- 4           •   Attachment 1: 2018 and 2017 Audited Transmission Financial Statements
- 5           •   Attachment 2: 2017 and 2016 Audited Transmission Financial Statements

**B2M LIMITED PARTNERSHIP**

**FINANCIAL STATEMENTS**

**DECEMBER 31, 2018**

# B2M LIMITED PARTNERSHIP INDEPENDENT AUDITORS' REPORT

To the Partners of B2M Limited Partnership

## *Opinion*

We have audited the financial statements of B2M Limited Partnership (the "Entity"), which comprise:

- the balance sheet as at December 31, 2018
- the statement of operations and comprehensive income for the year then ended
- the statement of partners' equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements, in all material respects, as at and for the year ended December 31, 2018 of the Entity are prepared in accordance with the financial reporting framework described in Note 2 in the 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 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 - Financial Reporting Framework*

We draw attention to Note 2 to the financial statements, which describes the applicable financial reporting framework.

The financial statements are prepared to provide the financial position, results of operations and cash flows of the partnership from the commencement of its commercial operations on December 16, 2014. 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.

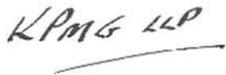
We also:

- 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.

**B2M LIMITED PARTNERSHIP  
INDEPENDENT AUDITORS' REPORT**

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.
- 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.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- 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.



Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada  
March 27, 2019

**B2M LIMITED PARTNERSHIP**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
For the years ended December 31, 2018 and 2017

Year ended December 31 <i>(thousands of Canadian dollars)</i>	2018	2017
<b>Revenues</b> <i>(Notes 6, 8)</i>	33,173	30,423
<b>Costs</b>		
Operation, maintenance and administration	1,407	1,325
Depreciation	7,172	7,172
	8,579	8,497
<b>Income before financing charges</b>	<b>24,594</b>	<b>21,926</b>
Financing charges <i>(Note 8)</i>	5,271	5,265
<b>Net income and comprehensive income</b>	<b>19,323</b>	<b>16,661</b>

See accompanying notes to Financial Statements.

**B2M LIMITED PARTNERSHIP**  
**BALANCE SHEETS**  
**At December 31, 2018 and 2017**

December 31 (thousands of Canadian dollars)	2018	2017
<b>Assets</b>		
Current assets:		
Cash and cash equivalents	9,733	4,805
Accounts receivable (Note 8)	3,038	3,884
Regulatory assets (Note 6)	1,925	3,055
	<b>14,696</b>	<b>11,744</b>
Property, plant and equipment (Note 3)	497,471	504,643
Other long-term assets:		
Regulatory assets (Note 6)	—	1,925
<b>Total assets</b>	<b>512,167</b>	<b>518,312</b>
<b>Liabilities</b>		
Current liabilities:		
Inter-company payable (Note 8)	1,630	3,606
Accrued liabilities	441	216
Accrued interest (Note 8)	1,072	1,029
Regulatory liabilities (Note 6)	1,635	—
	<b>4,778</b>	<b>4,851</b>
Long-term liabilities:		
Notes payable (Notes 4, 8)	301,841	305,641
<b>Total liabilities</b>	<b>306,619</b>	<b>310,492</b>
<i>Subsequent Event (Note 10)</i>		
Partners' equity (Note 7)	205,548	207,820
<b>Total liabilities and partners' equity</b>	<b>512,167</b>	<b>518,312</b>

See accompanying notes to Financial Statements.

On behalf of Hydro One Indigenous Partnerships GP Inc., in its capacity as general partner of B2M Limited Partnership:



Paul Dobson  
Sole Director

**B2M LIMITED PARTNERSHIP**  
**STATEMENTS OF PARTNERS' EQUITY**  
For the years ended December 31, 2018 and 2017

Year ended December 31, 2018 <i>(thousands of Canadian dollars, except number of units)</i>	Class A Units		Class B Units		Total	
	Number of units	Unit value	Number of units	Unit value	Number of units	Unit value
January 1, 2018	188,579,358	185,996	22,000,000	21,824	210,579,358	207,820
Distributions to partners		(19,288)		(2,307)		(21,595)
Net income and comprehensive income		17,326		1,997		19,323
<b>December 31, 2018</b>	<b>188,579,358</b>	<b>184,034</b>	<b>22,000,000</b>	<b>21,514</b>	<b>210,579,358</b>	<b>205,548</b>

Year ended December 31, 2017 <i>(thousands of Canadian dollars, except number of units)</i>	Class A Units		Class B Units		Total	
	Number of units	Unit value	Number of units	Unit value	Number of units	Unit value
January 1, 2017	188,579,358	185,735	22,000,000	21,823	210,579,358	207,558
Distributions to partners		(14,668)		(1,731)		(16,399)
Net income and comprehensive income		14,929		1,732		16,661
<b>December 31, 2017</b>	<b>188,579,358</b>	<b>185,996</b>	<b>22,000,000</b>	<b>21,824</b>	<b>210,579,358</b>	<b>207,820</b>

See accompanying notes to Financial Statements.

**B2M LIMITED PARTNERSHIP**  
**STATEMENTS OF CASH FLOWS**  
For the years ended December 31, 2018 and 2017

Year ended December 31 <i>(thousands of Canadian dollars)</i>	2018	2017
<b>Operating activities</b>		
Net income	19,323	16,661
Adjustments for non-cash items:		
Depreciation	7,172	7,172
Regulatory assets and liabilities	4,690	795
Changes in non-cash balances related to operations <i>(Note 9)</i>	1,114	(1,367)
<b>Net cash from operating activities</b>	<b>32,299</b>	<b>23,261</b>
<b>Financing activities</b>		
Notes payable repaid	(3,800)	(3,800)
Distributions to partners	(21,595)	(20,904)
Inter-company payable	(1,976)	(1,905)
<b>Net cash used in financing activities</b>	<b>(27,371)</b>	<b>(26,609)</b>
<b>Net change in cash and cash equivalents</b>	<b>4,928</b>	<b>(3,348)</b>
Cash and cash equivalents, beginning of year	4,805	8,153
<b>Cash and cash equivalents, end of year</b>	<b>9,733</b>	<b>4,805</b>

See accompanying notes to Financial Statements.

## **1. DESCRIPTION OF THE BUSINESS**

B2M Limited Partnership (B2M LP or the Partnership) was formed on March 22, 2013, under the laws of the Province of Ontario (Province). B2M LP is 65.71% owned by Hydro One Indigenous Partnerships GP Inc. (previously B2M GP Inc.) (HOIP GP or the General Partner), 34.19% owned by the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the Saugeen Ojibway Nation (SON), and 0.1% owned by Hydro One B2M LP Inc. (HO B2M LP). Both, HOIP GP and HO B2M LP are indirectly owned by Hydro One Inc. (Hydro One). The principal business of the Partnership is the operation, management and maintenance of an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to Hydro One's Milton Switching Station in the Town of Milton. On December 16, 2014, Hydro One's subsidiary, Hydro One Networks Inc., transferred the Bruce to Milton Line transmission assets totalling \$526 million to B2M LP. The asset transfer was financed by 60% debt (\$316 million) and 40% equity (\$210 million). The transfer of Bruce to Milton Line transmission assets is a common control transaction as Hydro One controlled these assets before and after the transfer.

B2M LP is managed by the General Partner. The General Partner was incorporated on March 22, 2013, under the *Business Corporations Act* (Ontario) under the name of B2M GP Inc. and changed its name to Hydro One Indigenous Partnerships GP Inc. in September 2018. HOIP GP holds the general partner interests and carries out the general partner responsibilities of B2M LP.

The electricity rates of the Partnership are regulated by the Ontario Energy Board (OEB).

### **Rate Setting**

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of \$39 million, \$36 million, \$37 million, \$38 million and \$37 million for the respective years. On May 10, 2018, the OEB issued its decision and rate order on B2M LP's 2018 transmission application reflecting revenue requirement of \$36 million, effective January 1, 2018.

## **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 (1) the Financial Statements were not prepared as though the transfer of the Bruce to Milton Line transmission assets had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information was not retrospectively adjusted, as required under US GAAP for common control transactions. These Financial Statements have been prepared to provide the financial position, results of operations and cash flows of the Partnership from the date of the transfer of the Bruce to Milton Line transmission assets on December 16, 2014. As a result, the financial statements may not be suitable for any other purpose.

The Partnership performed an evaluation of subsequent events through to March 27, 2019, 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 10 – Subsequent Event.

### **Use of Management Estimates**

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an on-going 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 asset impairments. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB.

### **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 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 regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. In addition, the Company has recorded regulatory liabilities that generally represent amounts that are refundable to future customers. The Company continually assesses the likelihood of recovery of each of its regulatory assets and continues to believe that it is probable that the OEB will include its regulatory assets and liabilities in setting future rates. If, at some future date, the Company judges that it is no longer probable that the OEB will include a regulatory asset or liability in setting future rates, the appropriate carrying amount would be reflected in results of operations in the period that the assessment is made.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2018 and 2017

**Revenue Recognition**

The Partnership adopted Accounting Standard Codification (ASC) 606 - *Revenue from Contracts with Customers* on January 1, 2018 using the retrospective method, without the election of any practical expedients. There was no material impact to the Partnership's revenue recognition policy as a result of adopting ASC 606, and no adjustments were made to prior period reported financial statements amounts.

Revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

**Income Taxes**

As a limited partnership, B2M LP is not a taxable entity for federal and provincial income tax purposes. Accordingly, no current or deferred tax expenses are recognized in the Partnership's financial statements. Tax on B2M LP's net income is borne by HOIP GP and HO B2M LP through the allocation of taxable income. The SON is a tax exempt entity and as such, is not subject to tax.

**Property, Plant and Equipment**

Property, plant and equipment is recorded at original cost, net of any accumulated impairment losses. The cost of additions, including betterments and replacements of 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, contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

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.

Easements include rights to use portions of licensed properties of Hydro One Networks Inc. for the purpose of operating and maintaining the Bruce to Milton Line transmission assets.

**Depreciation**

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The average service life and depreciation rates for the Partnership's assets are as follows:

Average Service Life	77 years
Depreciation Rates - Range	1% - 2%
Depreciation Rates - Average	1%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 Partnership evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of B2M LP's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the 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, 2018, no asset impairment had been recorded.

**Financial Assets and Liabilities**

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2018 and 2017

are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Partnership considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Partnership will not be able to collect amounts according to the original terms. The Partnership determines the classification of its financial assets and liabilities at the date of initial recognition.

**3. PROPERTY, PLANT AND EQUIPMENT**

December 31, 2018 (thousands of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Total
Transmission	429,727	24,966	404,761
Easements	96,721	4,011	92,710
	526,448	28,977	497,471

December 31, 2017 (thousands of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Total
Transmission	429,727	18,789	410,938
Easements	96,721	3,016	93,705
	526,448	21,805	504,643

**4. NOTES PAYABLE**

Notes payable consist of two promissory notes payable to B2M Trust, a subsidiary of Hydro One. The following table presents the balances of the promissory notes at December 31, 2018 and 2017:

December 31 (thousands of dollars)	2018	2017
1.64% note payable due April 2020	281,341	285,141
Floating-rate note payable due April 2020 <sup>1</sup>	20,500	20,500
	301,841	305,641

<sup>1</sup> The interest rate of the floating-rate note receivable is referenced to the OEB Demand Short-Term Debt Rate.

In 2018, B2M LP repaid \$3,800 thousand (2017 – \$3,800 thousand) of the promissory notes to B2M Trust.

**5. 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 Partnership 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 the Partnership 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, 2018 and 2017, the carrying amounts of cash and cash equivalents, accounts receivable, and inter-company payable are representative of fair value because of the short-term nature of these instruments.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2018 and 2017

**Fair Value Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2018 and 2017 is as follows:

December 31, 2018 <i>(thousands of dollars)</i>	Carrying Value	Fair Value	Level 1	Level 2	Level 3
<b>Assets:</b>					
Cash and cash equivalents	9,733	9,733	9,733	—	—
<b>Liabilities:</b>					
Inter-company payable	1,630	1,630	1,630	—	—
Notes payable	301,841	298,400	—	298,400	—
	303,471	300,030	1,630	298,400	—
<b>December 31, 2017 <i>(thousands of dollars)</i></b>					
	Carrying Value	Fair Value	Level 1	Level 2	Level 3
<b>Assets:</b>					
Cash and cash equivalents	4,805	4,805	4,805	—	—
<b>Liabilities:</b>					
Inter-company payable	3,606	3,606	3,606	—	—
Notes payable	305,641	301,817	—	301,817	—
	309,247	305,423	3,606	301,817	—

The fair value of the 1.64% note payable is based on unadjusted period-end market price for the same or similar debt of the same remaining maturity. The fair value of the floating-rate note payable is same as its carrying value because its interest rate is at the OEB Demand Short-Term Debt Rate.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2018 and 2017.

**Risk Management**

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Partnership's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Partnership is exposed to fluctuations in interest rates as a portion of its promissory notes contains a floating interest rate that is referenced to the 3-month Canadian dollar bankers' acceptance rate. The Partnership is not currently exposed to commodity price risk or foreign exchange risks.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Partnership's net income for the years ended December 31, 2018 and 2017.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2018 and 2017, there were no significant concentrations of credit risk with respect to any class of financial assets. The Partnership did not earn a significant amount of revenue from any individual customer.

Liquidity Risk

Liquidity risk refers to the Partnership's ability to meet its financial obligations as they come due. The Partnership meets its short-term liquidity requirements through the inter-company payable with Hydro One and funds from operations. The short-term liquidity available to the Partnership should be sufficient to fund normal operating requirements.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2018 and 2017

**6. REGULATORY ASSETS AND LIABILITIES**

Regulatory assets and liabilities arise as a result of the rate-setting process. B2M LP has recorded the following regulatory assets and liabilities:

December 31 (thousands of dollars)	2018	2017
<b>Regulatory assets:</b>		
Start-up costs	1,925	3,850
Foregone revenue deferral	—	1,130
Total regulatory assets	1,925	4,980
Less: current portion	(1,925)	(3,055)
	—	1,925
<b>Regulatory liabilities:</b>		
Foregone revenue deferral	1,635	—
Total regulatory liabilities	1,635	—
Less: current portion	(1,635)	—
	—	—

**Start-up Costs**

In December 2015, the OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of \$7,700 thousand start-up costs over the 2016 to 2019 test years at a rate of \$1,925 thousand per year. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

**Foregone Revenue Deferral**

In June 2017, the OEB approved the foregone revenue account for B2M LP to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balance of this account was recovered from ratepayers over a one-year period ended December 31, 2018. As part of its May 2018 decision, the OEB also directed B2M LP to record in this account any revenue collected in 2018 in excess of the final approved 2018 B2M LP revenue requirement. This amount will be returned to ratepayers over a one-year period ending December 31, 2019.

**7. PARTNERS' EQUITY**

B2M LP is authorized to issue an unlimited number of Class A and Class B units. The Class A and Class B units are voting and participate equally in profits, losses and capital distributions of B2M LP. The Class A and Class B units are equal with respect to all rights, benefits obligations and limitations provided under the Limited Partnership Agreement. Any units issued by B2M LP must be first offered to the existing partners in proportion to their ownership interests. At December 31, 2018 and 2017, B2M LP had 188,579,358 Class A units issued and outstanding, and 22,000,000 Class B units issued and outstanding.

As the SON is a tax exempt entity, the amount of income or loss corresponding to taxes recovered in transmission rates is allocated to the taxable partners, HOIP GP and HO B2M LP (Hydro One Partners), and the remaining balance is allocated to all partners in proportion to their ownership interests.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2018 and 2017

At December 31, 2018 and 2017, partners' equity was allocated to the SON and the Hydro One Partners as follows:

Year ended December 31, 2018 <i>(thousands of dollars, except number of units)</i>	SON	Hydro One Partners	Total
<b>Class A Units</b>	50,000,000	138,579,358	188,579,358
Class A - number of units - December 31, 2018			
Class A unit value - January 1, 2018	49,600	136,396	185,996
Distributions to partners	(5,242)	(14,046)	(19,288)
Net income and comprehensive income	4,539	12,787	17,326
<b>Class A unit value - December 31, 2018</b>	<b>48,897</b>	<b>135,137</b>	<b>184,034</b>
<b>Class B Units</b>	22,000,000	—	22,000,000
Class B - number of units - December 31, 2018			
Class B unit value - January 1, 2018	21,824	—	21,824
Distributions to partners	(2,307)	—	(2,307)
Net income and comprehensive income	1,997	—	1,997
<b>Class B unit value - December 31, 2018</b>	<b>21,514</b>	<b>—</b>	<b>21,514</b>
<b>Total partners' equity</b>			
Number of units - December 31, 2018	72,000,000	138,579,358	210,579,358
Partners' equity - January 1, 2018	71,424	136,396	207,820
Distributions to partners	(7,549)	(14,046)	(21,595)
Net income and comprehensive income	6,536	12,787	19,323
<b>Partners' equity - December 31, 2018</b>	<b>70,411</b>	<b>135,137</b>	<b>205,548</b>

Year ended December 31, 2017 <i>(thousands of dollars, except number of units)</i>	SON	Hydro One Partners	Total
<b>Class A Units</b>	50,000,000	138,579,358	188,579,358
Class A - number of units - December 31, 2017			
Class A unit value - January 1, 2017	49,599	136,136	185,735
Distributions to partners	(3,934)	(10,734)	(14,668)
Net income and comprehensive income	3,935	10,994	14,929
<b>Class A unit value - December 31, 2017</b>	<b>49,600</b>	<b>136,396</b>	<b>185,996</b>
<b>Class B Units</b>	22,000,000	—	22,000,000
Class B - number of units - December 31, 2017			
Class B unit value - January 1, 2017	21,823	—	21,823
Distributions to partners	(1,731)	—	(1,731)
Net income and comprehensive income	1,732	—	1,732
<b>Class B unit value - December 31, 2017</b>	<b>21,824</b>	<b>—</b>	<b>21,824</b>
<b>Total partners' equity</b>			
Number of units - December 31, 2017	72,000,000	138,579,358	210,579,358
Partners' equity - January 1, 2017	71,422	136,136	207,558
Distributions to partners	(5,665)	(10,734)	(16,399)
Net income and comprehensive income	5,667	10,994	16,661
<b>Partners' equity - December 31, 2017</b>	<b>71,424</b>	<b>136,396</b>	<b>207,820</b>

**8. RELATED PARTY TRANSACTIONS**

The Partnership is 65.81% indirectly owned by Hydro One and 34.19% owned by the SON. Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2018. The Independent Electricity System Operator (IESO) is a related party to the Partnership because it is controlled or significantly influenced by the Province. Transactions between the IESO and the Partnership are as follows:

The Partnership earns revenues for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Revenues from the IESO in 2018 were \$37,862 thousand (2017 – \$31,221 thousand), which was adjusted by \$4,689 thousand

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2018 and 2017

(2017 - \$798 thousand) to reflect the recognition of the net regulatory asset in the year. At December 31, 2018, included in accounts receivable were amounts due from the IESO of \$3,038 thousand (2017 – \$3,884 thousand).

**Hydro One and Subsidiaries**

Hydro One and its subsidiaries paid for expenses of the Partnership which will be reimbursed by the Partnership. Amounts due to Hydro One and its subsidiaries by the Partnership are included in the inter-company payable. At December 31, 2018, the Partnership had an inter-company payable balance of \$1,630 thousand (2017 – \$3,606 thousand).

Notes payable totalling \$301,841 thousand (2017 – \$305,641 thousand) are due to B2M Trust. Interest expense on these notes in 2018 was \$5,346 thousand (2017 – \$5,303 thousand). In 2018, B2M LP repaid \$3,800 thousand (2017 – \$3,800 thousand) of notes payable to B2M Trust. At December 31, 2018, B2M LP had accrued interest payable to B2M Trust of \$1,072 thousand (2017 – \$1,029 thousand).

**9. STATEMENTS OF CASH FLOWS**

The changes in non-cash balances related to operations consist of the following:

<i>Year ended December 31 (thousands of dollars)</i>	2018	2017
Accounts receivable	846	(1,176)
Accrued liabilities	225	(194)
Accrued interest	43	3
	1,114	(1,367)

**10. SUBSEQUENT EVENT**

**Distributions**

On January 23, 2019, distributions in the amount of \$4,505 thousand were paid, of which \$4,046 thousand and \$459 thousand were distributed to Class A and Class B unit holders, respectively.

**B2M LIMITED PARTNERSHIP**

**FINANCIAL STATEMENTS**

**DECEMBER 31, 2017**

**B2M LIMITED PARTNERSHIP  
INDEPENDENT AUDITORS' REPORT**

To the Partners of B2M Limited Partnership

We have audited the accompanying financial statements of B2M Limited Partnership, which comprise the balance sheet as at December 31, 2017, the statements of operations and comprehensive income, partners' equity and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information. The financial statements have been prepared by management in accordance with the basis of accounting in Note 2 to the financial statements.

*Management's Responsibility for the Financial Statements*

Management is responsible for the preparation of these financial statements in accordance with the basis of accounting in Note 2 to the financial statements; this includes determining that the basis of accounting is an acceptable basis for the preparation of these financial statements in the circumstances, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

*Auditors' Responsibility*

Our responsibility is to express an opinion on these financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

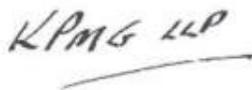
*Opinion*

In our opinion, the financial statements as at and for the year ended December 31, 2017 are prepared, in all material respects, in accordance with the basis of accounting in Note 2 to the financial statements.

*Basis of Accounting*

Without modifying our opinion, we draw attention to Note 2 to the financial statements, which describes the basis of accounting. The financial statements are prepared to provide the financial position, results of operations and cash flows of the partnership from the date of the transfer of the Bruce to Milton Line transmission assets on December 16, 2014. As a result, the financial statements may not be suitable for another purpose.

Our report is intended solely for B2M Limited Partnership and should not be used by parties other than B2M Limited Partnership.



Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada  
March 13, 2018

**B2M LIMITED PARTNERSHIP**  
**STATEMENTS OF OPERATIONS AND COMPREHENSIVE INCOME**  
For the years ended December 31, 2017 and 2016

Year ended December 31 <i>(thousands of Canadian dollars)</i>	2017	2016
<b>Revenues</b> <i>(Notes 6, 8)</i>	30,423	30,697
<b>Costs</b>		
Operation, maintenance and administration	1,325	1,084
Depreciation	7,172	7,172
	8,497	8,256
<b>Income before financing charges</b>	<b>21,926</b>	<b>22,441</b>
Financing charges <i>(Note 8)</i>	5,265	5,311
<b>Net income and comprehensive income</b>	<b>16,661</b>	<b>17,130</b>

See accompanying notes to Financial Statements.

**B2M LIMITED PARTNERSHIP**  
**BALANCE SHEETS**  
**At December 31, 2017 and 2016**

December 31 (thousands of Canadian dollars)	2017	2016
<b>Assets</b>		
Current assets:		
Cash and cash equivalents	4,805	8,153
Accounts receivable (Note 8)	3,884	2,708
Regulatory assets (Note 6)	3,055	1,925
	<b>11,744</b>	<b>12,786</b>
Property, plant and equipment (Note 3)	504,643	511,815
Other long-term assets:		
Regulatory assets (Note 6)	1,925	3,850
<b>Total assets</b>	<b>518,312</b>	<b>528,451</b>
<b>Liabilities</b>		
Current liabilities:		
Inter-company payable (Note 8)	3,606	8,516
Accrued liabilities	216	1,910
Accrued interest (Note 8)	1,029	1,026
	<b>4,851</b>	<b>11,452</b>
Long-term liabilities:		
Notes payable (Notes 4, 8)	305,641	309,441
<b>Total liabilities</b>	<b>310,492</b>	<b>320,893</b>
<i>Subsequent Event (Note 10)</i>		
Partners' equity (Note 7)	207,820	207,558
<b>Total liabilities and partners' equity</b>	<b>518,312</b>	<b>528,451</b>

See accompanying notes to Financial Statements.

On behalf of B2M GP Inc., in its capacity as general partner of B2M Limited Partnership:



Christopher Lopez  
Sole Director

**B2M LIMITED PARTNERSHIP**  
**STATEMENTS OF PARTNERS' EQUITY**  
For the years ended December 31, 2017 and 2016

Year ended December 31, 2017 <i>(thousands of Canadian dollars, except number of units)</i>	Class A Units		Class B Units		Total	
	Number of units	Unit value	Number of units	Unit value	Number of units	Unit value
January 1, 2017	188,579,358	185,735	22,000,000	21,823	210,579,358	207,558
Distributions to partners		(14,668)		(1,731)		(16,399)
Net income and comprehensive income		14,929		1,732		16,661
<b>December 31, 2017</b>	<b>188,579,358</b>	<b>185,996</b>	<b>22,000,000</b>	<b>22,766</b>	<b>210,579,358</b>	<b>207,820</b>

Year ended December 31, 2016 <i>(thousands of Canadian dollars, except number of units)</i>	Class A Units		Class B Units		Total	
	Number of units	Unit value	Number of units	Unit value	Number of units	Unit value
January 1, 2016	188,579,358	195,466	22,000,000	22,765	210,579,358	218,231
Distributions to partners		(25,118)		(2,685)		(27,803)
Net income and comprehensive income		15,387		1,743		17,130
<b>December 31, 2016</b>	<b>188,579,358</b>	<b>185,735</b>	<b>22,000,000</b>	<b>21,823</b>	<b>210,579,358</b>	<b>207,558</b>

See accompanying notes to Financial Statements.

**B2M LIMITED PARTNERSHIP**  
**STATEMENTS OF CASH FLOWS**  
For the years ended December 31, 2017 and 2016

Year ended December 31 <i>(thousands of Canadian dollars)</i>	2017	2016
<b>Operating activities</b>		
Net income	16,661	17,130
Adjustments for non-cash items:		
Depreciation	7,172	7,172
Regulatory asset	795	1,925
Changes in non-cash balances related to operations <i>(Note 9)</i>	(1,367)	253
<b>Net cash from operating activities</b>	<b>23,261</b>	<b>26,480</b>
<b>Financing activities</b>		
Notes payable repaid	(3,800)	(4,390)
Distributions to partners	(20,904)	(23,298)
Inter-company payable	(1,905)	(1,493)
<b>Net cash used in financing activities</b>	<b>(26,609)</b>	<b>(29,181)</b>
<b>Net change in cash and cash equivalents</b>	<b>(3,348)</b>	<b>(2,701)</b>
Cash and cash equivalents, beginning of year	8,153	10,854
<b>Cash and cash equivalents, end of year</b>	<b>4,805</b>	<b>8,153</b>

See accompanying notes to Financial Statements.

## 1. DESCRIPTION OF THE BUSINESS

B2M Limited Partnership (B2M LP or the Partnership) was formed on March 22, 2013, under the laws of the Province of Ontario (Province). B2M LP is 65.71% owned by B2M GP Inc. (B2M GP or the General Partner), 34.19% owned by the Chippewas of Nawash First Nation and the Chippewas of Saugeen First Nation, collectively referred to as the Saugeen Ojibway Nation (SON), and 0.1% owned by Hydro One B2M LP Inc. (HO B2M LP). Both, B2M GP and HO B2M LP are indirectly owned by Hydro One Inc. (Hydro One). The principal business of the Partnership is the operation, management and maintenance of an electricity transmission line (Bruce to Milton Line) in southwestern Ontario, from the Bruce Power facility in Kincardine to Hydro One's Milton Switching Station in the Town of Milton. On December 16, 2014, Hydro One's subsidiary, Hydro One Networks Inc., transferred the Bruce to Milton Line transmission assets totalling \$526 million to B2M LP. The asset transfer was financed by 60% debt (\$316 million) and 40% equity (\$210 million). The transfer of Bruce to Milton Line transmission assets is a common control transaction as Hydro One controlled these assets before and after the transfer.

B2M LP is managed by its general partner, B2M GP. The General Partner was incorporated on March 22, 2013, under the *Business Corporations Act* (Ontario). B2M GP holds the general partner interests and carries out the general partner responsibilities of B2M LP.

The electricity rates of the Partnership are regulated by the Ontario Energy Board (OEB).

## 2. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Accounting

These Financial Statements are prepared and presented in accordance with the accounting policies summarized below and in Canadian dollars. These policies are consistent with United States (US) Generally Accepted Accounting Principles (GAAP), with the exception that (1) the Financial Statements were not prepared as though the transfer of the Bruce to Milton Line transmission assets had occurred at the beginning of the year in which the transfer occurred and (2) the comparative year information has not been retrospectively adjusted, as required under US GAAP for common control transactions. These Financial Statements have been prepared to provide the financial position, results of operations and cash flows of the Partnership from the date of the transfer of the Bruce to Milton Line transmission assets on December 16, 2014. As a result, the financial statements may not be suitable for any other purpose.

The Partnership performed an evaluation of subsequent events through to March 13, 2018, the date these financial statements were available to be issued, to determine whether any events or transactions warranted recognition and disclosure in these financial statements. See note 10 – Subsequent Event.

### Use of Management Estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues, expenses, gains and losses during the reporting periods. Management evaluates these estimates on an on-going 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 asset impairments. Actual results may differ significantly from these estimates, which may be impacted by future decisions made by the OEB.

### Rate Setting

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of \$39 million, \$36 million, \$37 million, \$38 million and \$37 million for the respective years. On January 14, 2016, the OEB approved the B2M LP revenue requirement recovery through the 2016 Uniform Transmission Rates, and the establishment of a deferral account to capture costs of Tax Rate and Rule changes. On June 8, 2017, the OEB approved the 2017 rates revenue requirement of \$34 million, updated for the cost of capital parameters.

### 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 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 regulatory assets represent certain amounts receivable from future customers and costs that have been deferred for accounting purposes because it is probable that they will be recovered in future rates. The regulatory liabilities represent amounts that are refundable to future customers.

### Revenue Recognition

Revenues are collected through OEB-approved rates, which are based on an approved revenue requirement that includes a rate of return. Such revenue is recognized as electricity is transmitted and delivered to customers.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2017 and 2016

**Income Taxes**

As a limited partnership, B2M LP is not a taxable entity for federal and provincial income tax purposes. Accordingly, no current or deferred tax expenses are recognized in the Partnership's financial statements. Tax on B2M LP's net income is borne by B2M GP and HO B2M LP through the allocation of taxable income. The SON is a tax exempt entity and as such, is not subject to tax.

**Property, Plant and Equipment**

Property, plant and equipment is recorded at original cost, net of any accumulated impairment losses. The cost of additions, including betterments and replacements of 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, contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

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.

Easements include rights to use portions of licensed properties of Hydro One Networks Inc. for the purpose of operating and maintaining the Bruce to Milton Line transmission assets.

**Depreciation**

The cost of property, plant and equipment is depreciated on a straight-line basis based on the estimated remaining service life of each asset category. The average service life and depreciation rates for the Partnership's assets are as follows:

Average Service Life	77 years
Depreciation Rates - Range	1% - 2%
Depreciation Rates - Average	1%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, 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 Partnership evaluates whether the carrying value of such assets has been impaired. For such long-lived assets, impairment exists when the carrying value exceeds the sum of the future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset's carrying value is adjusted to its estimated fair value.

The carrying costs of B2M LP's long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. As at December 31, 2017, no asset impairment had been recorded.

**Financial Assets and Liabilities**

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity investments; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable which are measured at the lower of cost or fair value. Accounts receivable are classified as loans and receivables. The Partnership considers the carrying amount of accounts receivable to be a reasonable estimate of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Partnership will not be able to collect amounts according to the original terms. The Partnership determines the classification of its financial assets and liabilities at the date of initial recognition.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2017 and 2016

**3. PROPERTY, PLANT AND EQUIPMENT**

December 31, 2017 <i>(thousands of dollars)</i>	Property, Plant and Equipment	Accumulated Depreciation	Total
Transmission	429,727	18,789	410,938
Easements	96,721	3,016	93,705
	526,448	21,805	504,643

December 31, 2016 <i>(thousands of dollars)</i>	Property, Plant and Equipment	Accumulated Depreciation	Total
Transmission	429,727	12,611	417,116
Easements	96,721	2,022	94,699
	526,448	14,633	511,815

**4. NOTES PAYABLE**

Notes payable consist of two promissory notes payable to B2M Trust, a subsidiary of Hydro One. The following table presents the balances of the promissory notes at December 31, 2017 and 2016:

December 31 <i>(thousands of dollars)</i>	2017	2016
1.64% note payable due April 2020	285,141	288,941
Floating-rate note payable due April 2020 <sup>1</sup>	20,500	20,500
	305,641	309,441

<sup>1</sup> The interest rate of the floating-rate note receivable is referenced to the 3-month Canadian dollar bankers' acceptance rate, plus a margin.

In 2017, B2M LP repaid \$3,800 thousand (2016 – \$4,390 thousand) of the promissory notes to B2M Trust.

**5. 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 Partnership 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 the Partnership has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

**Non-Derivative Financial Assets and Liabilities**

At December 31, 2017 and 2016, the carrying amounts of cash and cash equivalents, accounts receivable, and inter-company payable are representative of fair value because of the short-term nature of these instruments.

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2017 and 2016

**Fair Value Hierarchy**

The fair value hierarchy of financial assets and liabilities at December 31, 2017 and 2016 is as follows:

December 31, 2017 (thousands of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
<b>Assets:</b>					
Cash and cash equivalents	4,805	4,805	4,805	—	—
<b>Liabilities:</b>					
Inter-company payable	3,606	3,606	3,606	—	—
Notes payable	305,641	301,817	—	301,817	—
	309,247	305,423	3,606	301,817	—
<b>December 31, 2016 (thousands of dollars)</b>					
	Carrying Value	Fair Value	Level 1	Level 2	Level 3
<b>Assets:</b>					
Cash and cash equivalents	8,153	8,153	8,153	—	—
<b>Liabilities:</b>					
Inter-company payable	8,516	8,516	8,516	—	—
Notes payable	309,441	309,057	—	309,057	—
	317,957	317,573	8,516	309,057	—

The fair value of the 1.64% note payable is based on unadjusted period-end market price for the same or similar debt of the same remaining maturity. The fair value of the floating-rate note payable is same as its carrying value because its interest rate is at the OEB Demand Short-Term Debt Rate.

There were no significant transfers between any of the fair value levels during the years ended December 31, 2017 and 2016.

**Risk Management**

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Partnership's business.

Market Risk

Market risk refers primarily to the risk of loss that results from changes in commodity prices, foreign exchange rates and interest rates. The Partnership is exposed to fluctuations in interest rates as a portion of its promissory notes contains a floating interest rate that is referenced to the 3-month Canadian dollar bankers' acceptance rate. The Partnership is not currently exposed to commodity price risk or foreign exchange risks.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in the Partnership's net income for the years ended December 31, 2017 and 2016.

Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2017 and 2016, there were no significant concentrations of credit risk with respect to any class of financial assets. The Partnership did not earn a significant amount of revenue from any individual customer.

Liquidity Risk

Liquidity risk refers to the Partnership's ability to meet its financial obligations as they come due. The Partnership meets its short-term liquidity requirements through the inter-company payable with Hydro One and funds from operations. The short-term liquidity available to the Partnership should be sufficient to fund normal operating requirements.

**6. REGULATORY ASSETS**

Regulatory assets arise as a result of the rate-setting process. B2M LP has recorded the following regulatory assets:

December 31 (thousands of dollars)	2017	2016
<b>Regulatory assets:</b>		
Start-up costs	3,850	5,775
Foregone revenue deferral	1,130	—
Total regulatory assets	4,980	5,775
Less: current portion	(3,055)	(1,925)
	1,925	3,850

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2017 and 2016

**Start-up Costs**

In December 2015, the OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of \$7,700 thousand start-up costs over the 2016 to 2019 test years at a rate of \$1,925 thousand per year. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

**Foregone Revenue Deferral**

In June 2017, the OEB approved the foregone revenue account for B2M LP to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balance of this account will be recovered from ratepayers over a one-year period ending December 31, 2018.

**7. PARTNERS' EQUITY**

B2M LP is authorized to issue an unlimited number of Class A and Class B units. The Class A and Class B units are voting and participate equally in profits, losses and capital distributions of B2M LP. The Class A and Class B units are equal with respect to all rights, benefits obligations and limitations provided under the Limited Partnership Agreement. Any units issued by B2M LP must be first offered to the existing partners in proportion to their ownership interests. At December 31, 2017 and 2016, B2M LP had 188,579,358 Class A units issued and outstanding, and 22,000,000 Class B units issued and outstanding.

As the SON is a tax exempt entity, the amount of income or loss corresponding to taxes recovered in transmission rates is allocated to the taxable partners, B2M GP and HO B2M LP (Hydro One Partners), and the remaining balance is allocated to all partners in proportion to their ownership interests.

At December 31, 2017 and 2016, partners' equity was allocated to the SON and the Hydro One Partners as follows:

Year ended December 31, 2017 <i>(thousands of dollars, except number of units)</i>	SON	Hydro One Partners	Total
<b>Class A Units</b>	50,000,000	138,579,358	188,579,358
Class A - number of units - December 31, 2017			
Class A unit value - January 1, 2017	49,599	136,136	185,735
Distributions to partners	(3,934)	(10,734)	(14,668)
Net income and comprehensive income	3,935	10,994	14,929
<b>Class A unit value - December 31, 2017</b>	<b>49,600</b>	<b>136,396</b>	<b>185,996</b>
<b>Class B Units</b>	22,000,000	—	22,000,000
Class B - number of units - December 31, 2017			
Class B unit value - January 1, 2017	21,823	—	21,823
Distributions to partners	(1,731)	—	(1,731)
Net income and comprehensive income	1,732	—	1,732
<b>Class B unit value - December 31, 2017</b>	<b>21,824</b>	<b>—</b>	<b>21,824</b>
<b>Total partners' equity</b>			
Number of units - December 31, 2017	72,000,000	138,579,358	210,579,358
Partners' equity - January 1, 2017	71,422	136,136	207,558
Distributions to partners	(5,665)	(10,734)	(16,399)
Net income and comprehensive income	5,667	10,994	16,661
<b>Partners' equity - December 31, 2017</b>	<b>71,424</b>	<b>136,396</b>	<b>207,820</b>

**B2M LIMITED PARTNERSHIP**  
**NOTES TO FINANCIAL STATEMENTS (continued)**  
For the years ended December 31, 2017 and 2016

Year ended December 31, 2016 (thousands of dollars, except number of units)	SON	Hydro One Partners	Total
<b>Class A Units</b>	50,000,000	138,579,358	188,579,358
Class A - number of units - December 31, 2016			
Class A unit value - January 1, 2016	51,739	143,727	195,466
Distributions to partners	(6,102)	(19,016)	(25,118)
Net income and comprehensive income	3,962	11,425	15,387
<b>Class A unit value - December 31, 2016</b>	<b>49,599</b>	<b>136,136</b>	<b>185,735</b>
<b>Class B Units</b>	22,000,000	—	22,000,000
Class B - number of units - December 31, 2016			
Class B unit value - January 1, 2016	22,765	—	22,765
Distributions to partners	(2,685)	—	(2,685)
Net income and comprehensive income	1,743	—	1,743
<b>Class B unit value - December 31, 2016</b>	<b>21,823</b>	<b>—</b>	<b>21,823</b>
<b>Total partners' equity</b>			
Number of units - December 31, 2016	72,000,000	138,579,358	210,579,358
Partners' equity - January 1, 2016	74,504	143,727	218,231
Distributions to partners <sup>1</sup>	(8,787)	(19,016)	(27,803)
Net income and comprehensive income	5,705	11,425	17,130
<b>Partners' equity - December 31, 2016</b>	<b>71,422</b>	<b>136,136</b>	<b>207,558</b>

<sup>1</sup> At December 31, 2016, \$1,500 thousand of distributions payable to SON was included in accrued liabilities and \$3,005 thousand of distributions payable to Hydro One Partners was included in inter-company payable.

## 8. RELATED PARTY TRANSACTIONS

The Partnership is 65.81% indirectly owned by Hydro One and 34.19% owned by the SON. Hydro One is owned by Hydro One Limited. The Province is a shareholder of Hydro One Limited with approximately 47.4% ownership at December 31, 2017. The Independent Electricity System Operator (IESO) is a related party to the Partnership because it is controlled or significantly influenced by the Province. Transactions between the IESO and the Partnership are as follows:

The Partnership earns revenues for transmission services from the IESO, based on uniform transmission rates approved by the OEB. Revenues from the IESO in 2017 were \$32,348 thousand (2016 – \$30,697 thousand). At December 31, 2017, included in accounts receivable were amounts due from the IESO of \$3,884 thousand (2016 – \$2,708 thousand).

### Hydro One and Subsidiaries

Hydro One and its subsidiaries paid for expenses of the Partnership which will be reimbursed by the Partnership. Amounts due to or from Hydro One and its subsidiaries by the Partnership are included in the inter-company payable or receivable. At December 31, 2017, the Partnership had an inter-company payable balance of \$3,606 thousand (2016 – \$8,516 thousand).

Notes payable totalling \$305,641 thousand (2016 – \$309,441 thousand) are due to B2M Trust. Interest expense on these notes in 2017 was \$5,303 thousand (2016 – \$5,311 thousand). In 2017, B2M LP repaid \$3,800 thousand (2016 – \$4,390 thousand) of notes payable to B2M Trust. At December 31, 2017, B2M LP had accrued interest payable to B2M Trust of \$1,029 thousand (2016 – \$1,026 thousand).

## 9. STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (thousands of dollars)	2017	2016
Accounts receivable	(1,176)	426
Accrued liabilities	(194)	(109)
Accrued interest	3	(64)
	<b>(1,367)</b>	<b>253</b>

**10. SUBSEQUENT EVENT**

**Distributions**

On January 30, 2018, distributions in the amount of \$4,505 thousand were paid, of which \$4,046 thousand and \$459 thousand were distributed to Class A and Class B unit holders, respectively.

1           **RECONCILIATION OF REGULATORY FINANCIAL RESULTS**  
 2           **WITH AUDITED FINANCIAL STATEMENTS (2018)**

	<b>Total per Exhibit A-06-02-01</b>	<b>Adjustments</b>	<b>Utility Income</b>
	<b>(a)</b>	<b>(b)</b>	<b>(c)</b>
<b>Revenues</b>			
Revenues	33,173		33,173
	33,173		33,173
<b>Costs</b>			
Operation, maintenance, and administration	1,407		1,407
Depreciation	7,172		7,172
	8,579		8,579
<b>Income before financing charges</b>	24,594		24,594
Financing charges	5,271		5,271
<b>Net Income and Comprehensive Income</b>	19,323		19,323

Witness: Samir Chhelavda



**Powering economies, connecting communities**



## Corporate Profile

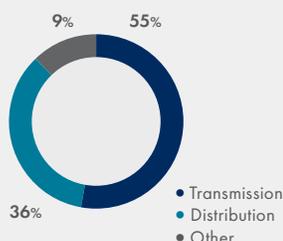
We are Ontario's largest electricity transmission and distribution provider with almost 1.4 million valued customers, almost \$25.7 billion in assets and 2018 annual revenues of almost \$6.2 billion. Our team of approximately 8,600 skilled and dedicated employees proudly build and maintain a safe and reliable electricity system which is essential to supporting strong and successful communities. In 2018, Hydro One invested almost \$1.6 billion in its 30,000 circuit kilometres of high-voltage transmission and 123,000 circuit kilometres of primary distribution networks and injected approximately \$1.3 billion into the economy by buying goods and services in Ontario. We are committed to the communities where we live and work through community investment, sustainability and diversity initiatives. We are one of only six utility companies in Canada to achieve the Sustainable Electricity Company designation from the Canadian Electricity Association. Through Hydro One Telecom Inc.'s extensive fibre optic network, we also provide advanced broadband telecommunications services on a wholesale basis. Hydro One Limited's common shares are listed on the Toronto Stock Exchange (TSX: H).

### Contents

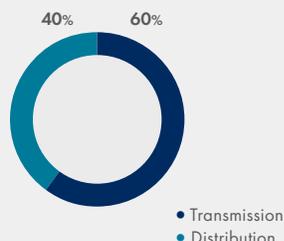
Year in Review	1
Message from the Chair	2
Message from the Acting President and CEO	4
Strategic Approach, Our Business	6
Operational Review	8
Stretching Every Dollar	9
Sustainability	12
Why invest in Hydro One?	14
Corporate Governance	15
Financial Report	16
Shareholder Information	IBC

## Financial Highlights

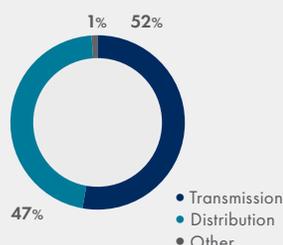
**Total Assets**  
**\$25.7b**



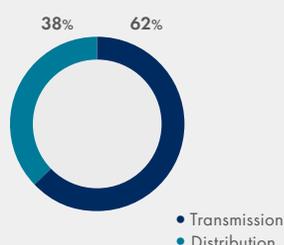
**Rate Base**  
**\$19.7b**



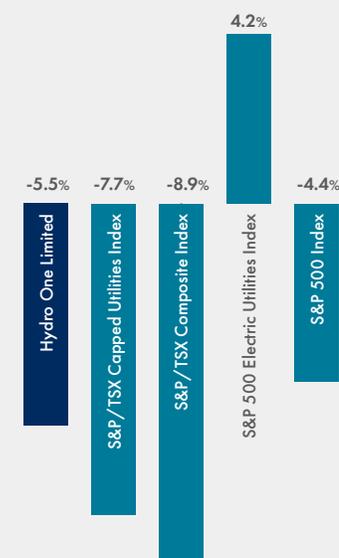
**Revenues**  
**\$3,251m**  
(Net of purchased power costs)



**Regulated Earnings**  
**\$1,368m**  
(Before financing charges and income taxes)



**Total Shareholder Return (TSR)<sup>1</sup>**  
January 1, 2018 to December 31, 2018



<sup>1</sup> Source: Bloomberg

Year ended December 31 (millions of dollars, except as otherwise noted)	2018	2017
Revenues	6,150	5,990
Purchased power	2,899	2,875
Revenues, net of purchased power <sup>1</sup>	3,251	3,115
Operation, maintenance and administration (OM&A) costs	1,105	1,066
Depreciation, amortization and asset removal costs	837	817
Financing charges	459	439
Income tax expense	915	111
<b>Net income (loss) attributable to common shareholders of Hydro One</b>	<b>(89)</b>	<b>658</b>
Basic earnings per common share (EPS)	(\$0.15)	\$1.11
Diluted EPS	(\$0.15)	\$1.10
Basic adjusted non-GAAP EPS (Adjusted EPS) <sup>1</sup>	\$1.35	\$1.17
Diluted adjusted EPS <sup>1</sup>	\$1.35	\$1.16
Net cash from operating activities	1,575	1,716
Funds from operations (FFO) <sup>1</sup>	1,572	1,579
Capital investments	1,575	1,567
Assets placed in-service	1,813	1,592
Transmission: Average monthly Ontario 60-minute peak demand (MW)	20,485	19,587
Distribution: Electricity distributed to Hydro One customers (GWh)	27,338	25,876
Debt to capitalization ratio <sup>2</sup>	55.6%	52.9%

Note: All amounts are in Canadian dollars unless otherwise specified.

<sup>1</sup> See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

<sup>2</sup> Debt to capitalization ratio has been presented at December 31, 2018 and 2017, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

This report contains forward-looking statements that are based on current expectations, estimates, forecasts and projections about our business and the industry in which we operate, and include beliefs and assumptions made by the management of our Company. Words such as "expect" and "will" are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. We do not intend, and we disclaim any obligation, to update any forward-looking statements, except as required by law.

## Year in Review

### SAFETY COMES FIRST

- Through Hydro One's *Journey to Zero* safety initiative, we achieved our 2018 performance target rate for recordable safety incidents of 1.1 per 200,000 hours worked – a 35% improvement since 2015.

### DRIVING DOWN COSTS

- Productivity savings of \$249.9 million since 2015.
- Annual operating costs have been reduced by 4% or \$41 million since 2015, resulting in savings<sup>1</sup>.
- New approach to storm preparation has reduced the time customers are without power following a storm by one-third, compared to similar-sized events five years ago.

### DELIVERING CUSTOMER SATISFACTION

- Residential and small business customer satisfaction was the highest in five years at 76%, while transmission customer satisfaction reached an all-time high of 90%.
- Billing accuracy reached an all-time high of 99.4%, while overdue accounts receivable fell to \$73 million – less than half of 2015.
- Repatriating approximately 400 Customer Contact Centre employees back into our business has improved customer service and reduced costs.

### IMPROVING THE GRID

- Compared to 2017, we improved the overall reliability of our distribution network by 14.2%.
- Clarington (\$238 million in capital costs) and Leamington (\$54 million in capital costs) stations were placed into service with strong project and cost discipline to support economic growth.
- More than \$1.8 billion of assets placed in-service in 2018.

### LEADERSHIP IN POWER RESTORATION

- Three Edison Electric Institute (EEI) Emergency Recovery Awards for outstanding power restoration efforts in Ontario and one Emergency Assistance Award for providing restoration support in the northeast U.S.
- Two teams of forestry technicians sent to Chico, California to support electrical system restoration efforts following devastating wildfires<sup>2</sup>.
- Following a tornado that destroyed the company's Merivale transmission station, Ottawa-area customers were restored within 48 hours with a temporary solution. The facility was fully rebuilt in approximately 12 weeks, returning to normal operation.

<sup>1</sup> Based on Hydro One Limited's total Operation, Maintenance & Administration costs (OM&A) excluding \$31 million in OM&A costs for Avista in 2017 and 2018. No costs related to the Avista transaction or the termination of the merger agreement have been paid for by Ontario ratepayers.

See section "Non-GAAP Measures" in the Management's Discussion and Analysis for more information.

<sup>2</sup> All costs incurred during mutual assistance operations are paid by the local utility receiving support.



### Powering Communities

**\$1.3b**

Goods and services procured in Ontario

**63%**

Increase in spending with Indigenous businesses since 2017

**8,600**

Regular and non-regular employees (approximate) across the province averaged over 2018

**\$2.6m**

In sponsorships and donations in communities where our customers work and live

**\$1.3m**

Donated by our employees and pensioners to charitable organizations

## Tom Woods

Hydro One's mandate is to deliver exceptional customer service and a safe and reliable source of electricity to homes and businesses in every community we serve.

The critical nature of our work directly translates to jobs, economic development, confidence and prosperity in cities and towns across the province.

In 2018, Hydro One transitioned to a new Board of Directors and I want to take this opportunity to officially welcome its new members: Cherie Brant, Blair Cowper-Smith, Anne Giardini, David Hay, Timothy Hodgson, Jessica McDonald, Russel Robertson, William Sheffield and Melissa Sonberg. This independent, highly-qualified Board has strong governance and industry experience as well as significant electricity, business and capital markets expertise.

Guided by its executive team, our introduction to Hydro One was seamless, efficient and comprehensive, enabling the Board to fully engage in all areas of the organization. We were reassured and indeed energized by the fundamental strength of the organization, the depth of its leadership and the resiliency of its employees in staying focused on the core business during a transitional year.

One of the top priorities for the Board is recruiting a new President and CEO. We have strict criteria for selecting this individual as they will be expected to lead the business to great heights.

Hydro One leadership will be accountable for achieving challenging performance targets by remaining focused on delivering exceptional customer service, driving efficiencies, improving the reliability of the electricity system and delivering strong financial performance for the benefit of shareholders and all Ontarians.

The Board will continue to provide strong oversight, guide forward-looking business strategies and commit to pursuing sustainability to secure the long-term viability of a well-run Hydro One. The company has a proud 100-plus year history, a dedicated team, and a solid foundation built with robust business fundamentals.



**Tom Woods**  
Chair of the Board  
of Directors

As we transform our business to meet the challenges of tomorrow, we will nurture Hydro One's results-oriented culture and pursue opportunities to innovate, be more efficient and provide exceptional customer service every day. We will be guided in these pursuits by Hydro One's commitment to continuous improvement, our "customer comes first" philosophy and the strength of our employees at all levels of the organization.

I want to thank our employees for their hard work and coming together through this period of leadership transition. Your commitment and willingness to go the extra mile to meet the needs of our customers have helped us build a stronger and better company.



Hydro One will continue to play a critical role in powering economies and connecting communities across this province. We remain dedicated to delivering greater value for our customers, employees, communities and all shareholders.

On behalf of the entire Board of Directors, thank you for your investment and ongoing support of Hydro One.

With best regards,

Tom Woods  
Chair of the Board of Directors



## Paul Dobson

Hydro One seeks excellence in every facet of our business, to the benefit of our customers, employees, communities and all shareholders. This approach became immediately clear to me after joining the organization in early 2018 and was further driven home in the sense of pride I felt being a part of a high-performance team that accomplished tremendous feats in a challenging year.

### Safety

Hydro One's safety performance was a top priority for management in 2018. Following the tragic loss in late 2017 of four Hydro One team members, we heightened our resolve to realize a vision of an injury-free workplace through our *Journey to Zero* initiative.

### Operational Excellence

Driving improvements in network reliability last year resulted in a 14.2% improvement in total average power outage duration for our distribution system over 2017. This is attributed to our application of modern technology to the grid, new storm prediction tools that allow for improved restoration response and our state-of-the-art vegetation management program.

In fact, this new vegetation process is an example of how the company is increasing productivity, driving costs down and generating efficiencies to improve our service to customers. In 2018, our forestry teams completed approximately 30,000 kilometres of work along power lines, nearly three times the work they did in 2017, with only a marginal increase in cost.

While we saw results drop for transmission reliability due mainly to highly abnormal weather, the quick, effective and innovative responses deployed by our crews to these

events was laudable. For example, after our Merivale transmission station was destroyed by a tornado in late September, a temporary solution was implemented within 48 hours to return service to customers and the facility was rebuilt in just 12 weeks.

### Customer

Due to a renewed effort to improve customer service and reliability in addition to other initiatives, residential and small business customer satisfaction, as well as transmission customer satisfaction reached the highest in five years and company history, respectively, in surveys last year. These results demonstrate a consistent dedication to putting customers first at all levels of the organization.

We actively seek to learn what is important to our customers and take action. For example, we repatriated approximately 400 employees in our Customer Contact Centre to provide better service and we conducted countless face-to-face meetings with customers to identify ways we can facilitate growth and strengthen local economies. Our First Nations outreach efforts also demonstrated ongoing efforts to support all customers' needs. In 2018, we met with the 88 Indigenous communities we serve and held over 700 one-on-one customer sessions.



**Paul Dobson**  
Acting President  
and CEO

### Economy

Our transmission system serves as the backbone for the economy, and our business plays a critical role in communities across the province. In 2018 alone, we injected approximately \$1.3 billion into the Ontario economy by buying goods and services from businesses across the province, including a 63% increase in spend with Indigenous businesses, as well as directly providing approximately 8,600 highly skilled jobs through the year.

### Avista

While we were naturally disappointed in the outcome of the Avista transaction, we will continue to pursue opportunities that make sense for our business and add value for all stakeholders.



### Employees

In January, we were honoured to be recognized by Forbes in its list of Canada's Best Employers for 2019. Based on a survey of over 8,000 people working at Canadian businesses with over 500 employees, our performance demonstrates efforts to create an engaged workforce and positive working environment.

In 2019, we will maintain our focus on continuous improvement and operational excellence, delivering efficiencies and exceptional customer service.

Finally, I would like to thank all teammates for their resilience and support during the leadership transition and for their dedication to driving improvements across the Hydro One business. I would like to thank the Board for their efforts during the transition.

Sincerely,

Paul Dobson  
Acting President and CEO

### Key Achievements

**\$249.9m**

Productivity savings since 2015

**14.2%**

Improvement in the overall reliability of our distribution network since 2017

**4% or \$41m<sup>1</sup>**

Reduction in annual operating costs since 2015

**\$1.3b**

Injected into the Ontario economy through purchases of local goods and services

**90%**

Highest-ever satisfaction rating from transmission customers

**4**

Edison Electric Institute Awards earned in 2018 for emergency power restoration

**76%**

Residential and small business customer satisfaction, highest in 5 years

### Addressing Ontario's Aging Power Infrastructure

A safe and reliable high-voltage transmission system is necessary to run and grow the large industrial companies, mines and manufacturing facilities that create job opportunities in Ontario.

Much of our system was built in the 1950s. One in four transformers are at the end of their expected service life, and nearly 10,000 of our steel towers are over 80 years old. To keep the public safe and reduce the number of power outages that can impact the economy and our customers' lives, we must invest in replacing, repairing and upgrading equipment in almost every community.

<sup>1</sup> Based on Hydro One Limited's total Operation, Maintenance & Administration costs (OM&A) excluding \$31 million in OM&A costs for Avista in 2017 and 2018. No costs related to the Avista transaction or the termination of the merger agreement will be paid for by Ontario ratepayers. See section "Non-GAAP Measures" in the Management's Discussion and Analysis for more information.

# Strategic Approach

We aim to continue strengthening our core business in order to deliver greater value for our customers, employees, communities and shareholders.

**OUR STRATEGIC PILLARS:**

**Customers First:**

Exceeding our customers’ needs and expectations is at the core of everything we do. We are focused on improving our customers’ experience through fast, flexible and convenient service.

**Cost Efficiency:**

We are committed to investing carefully, reducing costs and stretching every dollar we spend to efficiently help the most customers.

**Operational Excellence:**

A continuous drive to improve our transmission and distribution networks means we are constantly raising performance and standards.

**Investing in our Future:**

Invest in innovation to improve service reliability, the efficiency of our business and the long-term viability of the company. We will expand our rate base, pursue organic growth and innovate for the benefit of stakeholders.

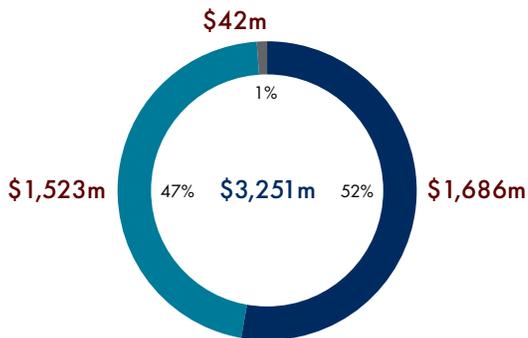
**Sustainability:**

We understand that improving our performance depends on incorporating sustainability into all aspects of our business.



## Our Business: At-a-Glance

Revenues (net of Purchased Power)



Segmented Assets



**Business Description**

**Transmission**

Our transmission system transmits high-voltage electricity from nuclear, hydroelectric, natural gas, wind and solar sources to our distribution company and industrial customers across Ontario. Hydro One owns and operates approximately 30,000 circuit kilometres of high-voltage transmission lines.

**Distribution**

The Hydro One distribution system is the largest in Ontario. It consists of approximately 123,000 circuit kilometres of primary low-voltage power lines serving almost 1.4 million customers. As well, Hydro One Remote Communities serves customers in one grid-connected and 21 off grid communities in Ontario’s far north.

**Other and Telecom**

Consists of a telecommunications business and certain corporate activities. Hydro One Telecom offers organizations a diverse, secure and highly reliable broadband connectivity solution.

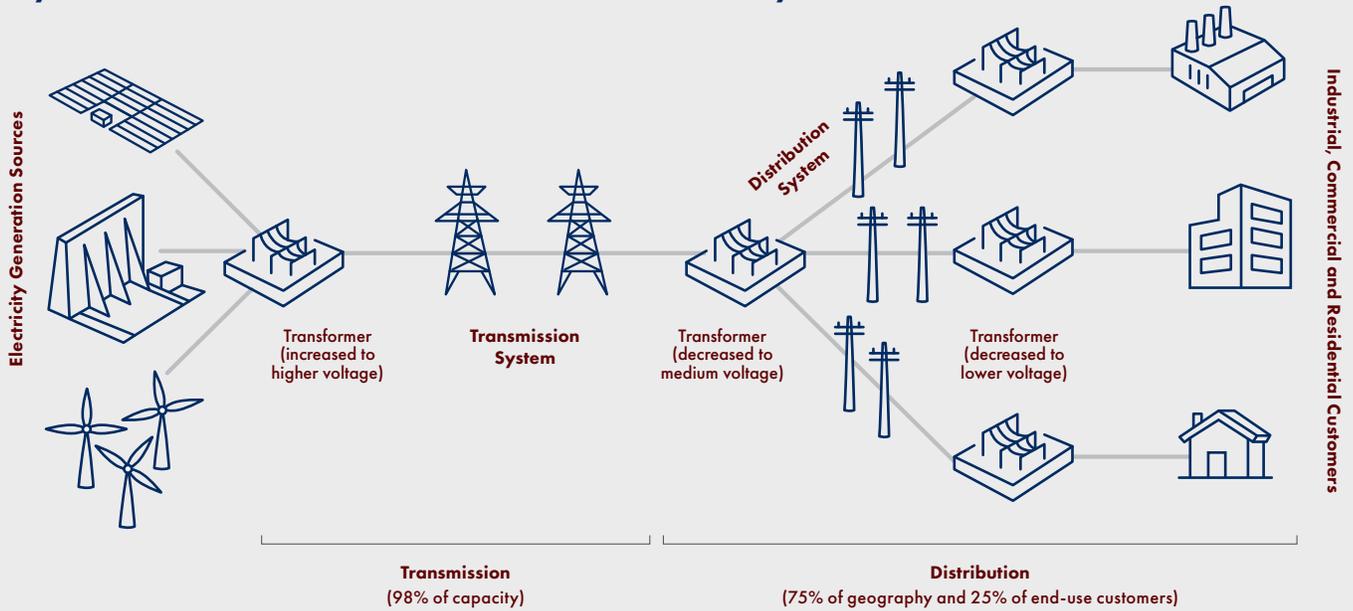
**Customer Segments**

- Large directly connected industrial customers
- Local distribution companies
- Large generators

- Residential and business customers
- Municipal utility customers
- Small or micro generators

- Data centres
- Cloud service providers
- Telecommunications services and public sector entities
- Internet service providers
- Enterprises

# 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. We own and operate nearly \$25.7 billion in assets and have annual revenues of almost \$6.2 billion. Our communities are proudly and safely serviced by a team of skilled and dedicated employees.

## Major Projects

### Niagara Reinforcement Project



A new 76 kilometre transmission line in southwestern Ontario to serve the growing Niagara area.

Estimated Total Project Cost (\$ millions)

**\$130**

Capital Cost to-date (\$ millions)

**\$121**

Anticipated In-service Date

**2019**

### Richview Transmission Station



Replacement of 50-year-old equipment to ensure reliable power supply to the City of Toronto and surrounding communities.

Estimated Total Project Cost (\$ millions)

**\$102**

Capital Cost to-date (\$ millions)

**\$99**

Anticipated In-service Date

**2020**

### East-West Tie Station Expansion



Hydro One is performing station upgrades to our Lakehead, Marathon and Wawa transmission stations. The upgrades are necessary to support the East-West Tie Line project, a priority project in the Province of Ontario's Long-Term Energy Plan.

Estimated Total Project Cost (\$ millions)

**\$157**

Capital Cost to-date (\$ millions)

**\$16**

Anticipated In-service Date

**2022<sup>1</sup>**

<sup>1</sup> The majority of the project will be in-service in 2021, enabling the connection and energization of the new East-West Tie transmission line. Additional work to complete the upgrades will be in-service in 2022.

# Operational Review



## Putting our Customers First

We delivered a number of far-reaching initiatives that focused on what is best for our customers.

Insourcing approximately 400 employees to our Customer Contact Centre has improved customer service and reduced costs, while our redesigned bill is easier for customers to understand.

Proactive measures to help customers who are behind on their bills, while avoiding disconnections wherever possible, have reduced overdue accounts receivable by half – down to \$73 million from \$148 million in 2015.

Our customer care team also increased Hydro One’s presence in First Nation communities across the province, conducting face-to-face meetings with customers and offering measures to address affordability.

A relentless focus on customer service resulted in improved satisfaction survey scores. Residential and small business customer satisfaction was the highest in five years at 76%, while transmission customer satisfaction reached an all-time high of 90%, reflecting a company-wide dedication to improving customer service.

### Energy Conservation

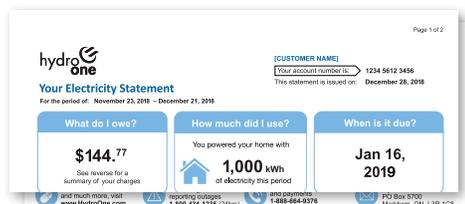
We achieved 92% of our six-year energy conservation target in only four years. Our energy conservation team conducted over 1,250 visits with our medium to large commercial and industrial customers and supported over 800 energy efficiency projects during the year.

Right: Hydro One’s redesigned residential bill has improved customer comprehension and reduced calls to the company’s Customer Contact Centre.

### Billing Accuracy (%)



### Overdue Accounts Receivable (\$ millions)





## Stretching Every Dollar

### We strive to do more for less

Since 2015, Hydro One has cut operation, maintenance and administrative (OM&A) costs by 4% – or \$41 million<sup>1</sup> – through efficiencies, new technology and other cost-saving initiatives.

Productivity savings of \$135.5 million in 2018 brings the total saved since 2015 to \$249.9 million. The top productivity savings in 2018 are from procurement initiatives, fleet rationalization, contract negotiations in information solutions and cable locate outsourcing.

### Productivity Savings (\$ millions)



**Cumulative: \$249.9 million**

### Streamlining our Work

In 2018, we completed the transition of our vegetation management program from a 10-year to a 3-year cycle, focusing on trimming problem trees and vegetation more often to improve the overall safety and reliability of the system. Our forestry teams completed approximately 30,000 kilometres of work along power lines, nearly three times the work they did in 2017, with only a marginal increase in cost.



**4%**

reduction in operating costs since becoming a publicly traded company in 2015<sup>1</sup>

**3x**

In 2018, our forestry teams completed nearly three times the work done in 2017, with only a marginal increase in cost

<sup>1</sup> Based on Hydro One Limited's total Operation, Maintenance & Administration costs (OM&A) excluding \$31 million in OM&A costs for Avista in 2017 and 2018. No costs related to the Avista transaction or the termination of the merger agreement will be paid for by Ontario ratepayers. See section "Non-GAAP Measures" in the Management's Discussion and Analysis for more information.

## Operating with Excellence



We made significant progress in improving Hydro One’s safety performance, achieving our 2018 target of 1.1 recordable injuries per 200,000 hours worked – a 35% improvement since 2015. We have a commitment to an injury-free workplace through our *Journey to Zero* initiative, which focuses on enhancing personal leadership in order to reduce workplace hazards.

The large number of severe weather events in 2018 resulted in five Force Majeure incidents<sup>1</sup>. Three incidents were within six weeks of each other, requiring crews to restore power to over 1.4 million customers in aggregate – more than all of 2017.

### Our Distribution Network

We improved the overall reliability of our distribution network by 14.2% compared to 2017. These improvements included more system oversight, our new vegetation management program, modernizing equipment, being more proactive in preparing for storms and targeting equipment upgrades to circuits that were causing the most power outages.

### Our Transmission Network

While transmission reliability and outage duration results dropped slightly during the year, mainly due to major equipment failures and severe weather, crews worked tirelessly to quickly and safely restore power.

We experienced significant events at our Gerrard, Minden and Finch stations. Further, our Merivale station was destroyed by a tornado in late September. While customers were restored within 48 hours with a temporary solution, the facility required 12 weeks of extensive work to rebuild.

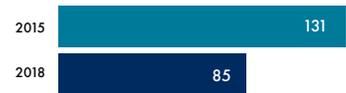


Merivale Transmission Station near Ottawa after a tornado destroyed the facility on September 21, 2018.

### WORKPLACE SAFETY

**35%**

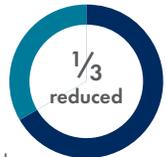
Improvement in recordable workplace injuries since 2015.



### CUSTOMER SERVICE

#### Improved Restoration Time

- We have reduced the time customers are without power following a storm by one-third since a similar-sized event five years ago.
- The overall reliability of our distribution network improved by 14.2% compared to 2017.



## Investing in our Future

We invest in technology and infrastructure modernization to ensure our business evolves and grows to meet the needs of our customers.

In 2018, we made total capital investments of approximately \$1.6 billion to ensure the long-term reliability of Ontario's electricity system and placed more than \$1.8 billion worth of new assets in-service. We completed one of the largest-ever station builds in company history, bringing the flagship Clarington Station into service on-time and under budget. The Leamington station was also brought into service as planned.

### Pursuing Organic Growth

In 2018, we successfully integrated Hydro One Sault Ste. Marie LP into our Hydro One Networks operations. As well, we announced an agreement to acquire the business and distribution assets of Peterborough Distribution Inc. and have submitted a new application with the Ontario Energy Board to acquire Orillia Power Distribution Corporation.

**200+**  
new apprentices  
hired in 2018

**\$6.5b**  
of assets placed  
in-service over  
the last 4 years

### Investing for Tomorrow

Not only do our investments maintain the safety and integrity of our system, they also contribute to local communities by creating jobs, new skills and new opportunities. In 2018, we hired over 200 apprentices into skilled trades, representing a renewal of our workforce.



# Sustainability

At Hydro One, we understand that our long-term performance depends on incorporating sustainability into all aspects of our business. In 2018, we continued building our sustainability strategy, and remain committed to setting up a corporate-wide vision and program that builds value for all stakeholders.



**3 hectares**  
Approximate size of new pollinator planting established to help restore monarch butterfly habitats

## Environmental Management

Hydro One seeks to avoid or minimize its impact on the environment because we understand this supports business interests and our commitment to being a sustainable company. We deliver electricity that is among the cleanest in North America.

Partnerships have helped further our biodiversity goals. We established approximately three hectares of new pollinator planting in Ottawa with the Canadian Wildlife Federation as part of a multi-stakeholder project to assess species value resulting from restoration of monarch butterfly habitats. We also collaborated with the Briarbrook Brookside Morgan's Grant Community Association to establish pollinator friendly plots and new management techniques on the community's electricity corridor.

## People and Potential

Hydro One pursues a culture of inclusion because it makes us stronger, more innovative and helps ensure we have the right skill set and perspectives to succeed in the future.

In 2018, while representation of women in executive positions decreased slightly by 0.7% to 36.4%, we were able to increase representation of visible minorities in executive positions to 15.6% from 11.4% in 2017. We advanced our Indigenous hiring plans and will pursue our multi-year plan to enhance future performance.

We celebrated Pride Month for the first time, flying rainbow flags at locations across the province, distributing *I Stand for Inclusion* stickers and creating our "PrideOne Employee Resource Group" for LGBTQ2+ employees and their allies.

We worked with union leadership on the mutually beneficial renewal of a two-year collective agreement with the Power Workers Union, which covers approximately 4,000 employees in critical front-line roles until March 31, 2020.

To better support our employees and pensioners, we refreshed *The Power to Give*, our charitable giving program. Last year, our employees and pensioners generously donated almost \$1.3 million.



# \$1.3m

In donations by employees and pensioners to causes that matter to them



### OUR PEOPLE

Hydro One was recognized by Forbes on its list of Canada's Best Employers 2019.

## 5,643

Regular employees<sup>1</sup>

## 2,948

Non-regular employees<sup>2</sup>

## Powering Economies

We support Ontario by buying goods and services from businesses across the province. In 2018, approximately \$1.3 billion was injected into the Ontario economy through procurement. This includes a 63% increase in spend since 2017 with Indigenous businesses, the largest amount to date, and supports our goal to become the primary business partner of Indigenous communities in Ontario by 2021.

In 2018, we met with the 88 Indigenous communities we serve and held over 700 one-on-one customer sessions. Following extensive community consultations, we completed the commercial terms on a business partnership with the Six Nations of the Grand River Development Corporation and the Mississaugas of the Credit First Nation on the Niagara Reinforcement Transmission Line Project.

Hydro One has a strong history of giving back to the communities where our people and customers live and work. In 2018, we invested \$2.6 million through sponsorships and donations with local programs and activities across the province.



### COMMUNITY INVESTMENT



Since 2003, Hydro One has been a proud sponsor of the *Little Native Hockey League* tournament, which hosts over 200 teams from First Nations across Ontario. The largest event of its kind in the province, the tournament promotes respect, citizenship, sportsmanship and education with Indigenous youth.

<sup>1</sup> In 2018, Hydro One changed its counting methodology for full-time regular and non-regular employees. Prior year figures referenced employment as at year-end December 31.

<sup>2</sup> In 2018, the methodology changed to reflect the average employment throughout the year.

<sup>2</sup> Non-regular includes: temporary and casual employees.

# Why invest in Hydro One?

Investing in Hydro One offers a unique opportunity to participate in the transformation of a large-scale regulated electric utility.

**ONE**  
**Performance-based Culture**

Transformation into a commercially-oriented, cost conscious, customer focused organization with a performance culture under Ontario’s emerging incentive-based regulation.

**TWO**  
**Stable Operating Environment**

Business is predominately (99%) rate-regulated in a constructive, stable, transparent and collaborative regulatory environment.

Resilient workforce in challenging environments.

Fully independent Board.

**THREE**  
**Predictable Growth**

Pure-play electric transmission and local distribution company with an aging infrastructure that requires investment and no commodity price exposure.

**\$6.5b**  
 4-year total of  
 capital investment

**FOUR**  
**Attractive Dividend**

Stable and growing dividend with a 70–80% target payout ratio<sup>1</sup> that is underpinned by strong cash flows from predictable rate base growth.

**FIVE**  
**Strong Balance Sheet**

Solid investment grade balance sheet.



**Credit Profile**

Rating Agency	Long-Term Debt Rating	Short-Term Debt Rating	Outlook
DBRS Limited	A (high)	R-1 (low)	stable
Moody's	Baa1	Prime-2	stable
S&P	A-	A-1 (low)	negative

<sup>1</sup> Payout ratio was 67% of Adjusted EPS in 2018

# Corporate Governance

## Board of Directors and Committees

	Audit	Governance	Human Resources	Health, Safety, Environmental and Indigenous Peoples
Tom Woods (Chair)				
Cherie Brant		•		•
Blair Cowper-Smith		★	•	
Anne Giardini	•			★
David Hay	•			•
Timothy Hodgson		•	•	
Jessica McDonald	•		•	
Russel Robertson	•		•	
William Sheffield	★			•
Melissa Sonberg		•	★	

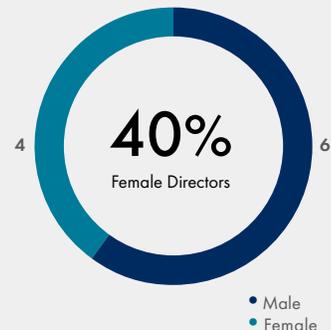
★ Chair • Committee Member

### 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 Diversity



### 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](http://www.HydroOne.com/Investors).

# Financial Report



## Contents

Notice to Reader	17
Amended Management's Discussion and Analysis	18
Amended Consolidated Financial Statements	65
Notes to Amended Consolidated Financial Statements	69
Board of Directors and Senior Leadership	110
Corporate and Shareholder Information	IBC

## Notice to Reader

---

Please be advised that Hydro One Limited (Hydro One or the Company) is filing Amended Consolidated Financial Statements and Amended Management's Discussion and Analysis (MD&A) for the period ended December 31, 2018, amending the documents previously filed to reflect the following changes:

1. The Consolidated Statements of Operations and Comprehensive Income, Consolidated Balance Sheets, Consolidated Statements of Changes in Equity and Consolidated Statements of Cash Flows and the relevant notes to the Consolidated Financial Statements for Income Taxes, Regulatory Assets and Liabilities, Segment Reporting, and Subsequent Events were updated to reflect the impact of the March 7, 2019 decision issued by the Ontario Energy Board (OEB) relating to the Deferred Tax Asset portion of the OEB's decision on Hydro One Networks' 2017 and 2018 transmission revenue requirement, for which the OEB previously granted a Motion to Review and Vary (DTA Decision) as disclosed in the Audited Consolidated Financial Statements Note 32(D) – Subsequent Events (OEB Regulatory Decisions) and Note 12 – Regulatory Assets and Liabilities.
2. MD&A was updated to reflect the impact of the DTA Decision, including the Consolidated Financial Highlights and Statistics, Overview, Results of Operations, Selected Annual Financial Statistics, Quarterly Results of Operations, Regulation, Non-GAAP Measures, Risk Management and Risk Factors, Summary of Fourth Quarter Results of Operations, Hydro One Holdings Limited – Unaudited Consolidating Summary Financial Information, and Forward-Looking Statements and Information.

The DTA Decision is a Type I subsequent event under United States Generally Accepted Accounting Principles (US GAAP) and as such the Company is required to update the Consolidated Financial Statements and MD&A to reflect the subsequent event in connection with filing its annual reports on Form 40-F with the US Securities and Exchange Commission, so that they contain the current information required at March 25, 2019, the date of approval of the annual report on Form 40-F.

Other than as expressly set forth above, the Amended Consolidated Financial Statements and Amended MD&A do not purport to update or restate the information in the original Consolidated Financial Statements and MD&A or reflect any events that occurred after the date of the filing of the original Consolidated Financial Statements and MD&A other than changes to the sections as expressly set forth above.

The Amended Consolidated Financial Statements and Amended MD&A have been filed electronically at [www.sedar.com](http://www.sedar.com) and at [www.sec.gov/edgar.shtml](http://www.sec.gov/edgar.shtml), and also on the Company's website at [www.HydroOne.com/Investors](http://www.HydroOne.com/Investors).

# Amended Management's Discussion and Analysis

For the years ended December 31, 2018 and 2017

The following Amended Management's Discussion and Analysis (MD&A) of the financial condition and results of operations should be read together with the amended 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, 2018. The Consolidated Financial Statements are presented in Canadian dollars and have been prepared in accordance with United States (US) Generally Accepted Accounting Principles (GAAP). All financial information in this MD&A is presented in Canadian dollars, unless otherwise indicated.

The Company has prepared this MD&A in accordance with National Instrument 51-102 – Continuous Disclosure Obligations of the Canadian Securities Administrators. Under the US/Canada Multijurisdictional Disclosure System, the Company is permitted to prepare this MD&A in accordance with the disclosure requirements of Canada, which can vary from those of the US. This MD&A provides information for the year ended December 31, 2018, based on information available to management as of February 20, 2019, other than with respect to information relating to the subsequent events disclosed in Note 32(D) to the Consolidated Financial Statements, dated March 25, 2019.

## CONSOLIDATED FINANCIAL HIGHLIGHTS AND STATISTICS

Year ended December 31 (millions of dollars, except as otherwise noted)

	2018	2017	Change
Revenues	6,150	5,990	2.7%
Purchased power	2,899	2,875	0.8%
Revenues, net of purchased power <sup>1</sup>	3,251	3,115	4.4%
Operation, maintenance and administration (OM&A) costs	1,105	1,066	3.7%
Depreciation, amortization and asset removal costs	837	817	2.4%
Financing charges	459	439	4.6%
Income tax expense	915	111	724.3%
<b>Net income (loss) attributable to common shareholders of Hydro One</b>	<b>(89)</b>	<b>658</b>	<b>(113.5%)</b>
Basic earnings per common share (EPS)	\$ (0.15)	\$ 1.11	(113.5%)
Diluted EPS	\$ (0.15)	\$ 1.10	(113.6%)
Basic adjusted non-GAAP EPS (Adjusted EPS) <sup>1</sup>	\$ 1.35	\$ 1.17	15.4%
Diluted Adjusted EPS <sup>1</sup>	\$ 1.35	\$ 1.16	16.4%
Net cash from operating activities	1,575	1,716	(8.2%)
Funds from operations (FFO) <sup>1</sup>	1,572	1,579	(0.4%)
Capital investments	1,575	1,567	0.5%
Assets placed in-service	1,813	1,592	13.9%
Transmission: Average monthly Ontario 60-minute peak demand (MW)	20,485	19,587	4.6%
Distribution: Electricity distributed to Hydro One customers (GWh)	27,338	25,876	5.7%
	2018	2017	
Debt to capitalization ratio <sup>2</sup>	55.6%	52.9%	

1 See section "Non-GAAP Measures" for description and reconciliation of basic and diluted Adjusted EPS, FFO and Revenues, net of purchased power.

2 Debt to capitalization ratio has been presented at December 31, 2018 and 2017, and has been calculated as total debt (includes total long-term debt, convertible debentures and short-term borrowings, net of cash and cash equivalents) divided by total debt plus total shareholders' equity, including preferred shares but excluding any amounts related to noncontrolling interest.

## Amended Management's Discussion and Analysis

### OVERVIEW

Hydro One is the largest electricity transmission and distribution company in Ontario. Through its wholly-owned subsidiary, Hydro One Inc., Hydro One owns and operates substantially all of Ontario's electricity transmission network, and approximately 123,000 circuit kilometres of primary low-voltage distribution network. Hydro One has three business segments: (i) transmission; (ii) distribution; and (iii) other business.

For the years ended December 31, 2018 and 2017, Hydro One's business segments accounted for the Company's total revenues, net of purchased power, as follows:

Year ended December 31	2018	2017
Transmission	52%	51%
Distribution	47%	48%
Other	1%	1%

At December 31, 2018 and 2017, Hydro One's business segments accounted for the Company's total assets as follows:

December 31	2018	2017
Transmission	55%	53%
Distribution	36%	36%
Other	9%	11%

#### Transmission Segment

Hydro One's transmission business owns, operates and maintains Hydro One's transmission system, which accounts for approximately 98% of Ontario's transmission capacity based on revenue approved by the Ontario Energy Board (OEB). The 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 in respect of the Bruce-to-Milton transmission line. The transmission business is rate-regulated and earns revenues mainly from charging transmission rates that are approved by the OEB.

	2018	2017
Electricity transmitted <sup>1</sup> (MWh)	137,436,546	132,090,992
Transmission lines spanning the province (circuit-kilometres)	30,166	30,290
Rate base (millions of dollars)	11,870	11,251
Capital investments (millions of dollars)	985	968
Assets placed in-service (millions of dollars)	1,164	889

<sup>1</sup> Electricity transmitted represents total electricity transmission in Ontario by all transmitters.

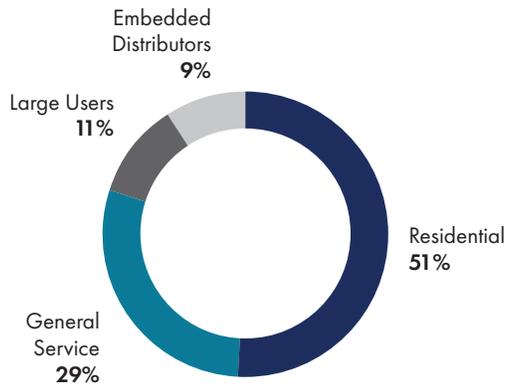
#### Distribution Segment

Hydro One's distribution business is the largest in Ontario and consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. (Hydro One Remote Communities). The distribution business is rate-regulated and earns revenues mainly from charging distribution rates that are approved by the OEB.

	2018	2017
Electricity distributed to Hydro One customers (GWh)	27,338	25,876
Electricity distributed through Hydro One lines (GWh) <sup>1</sup>	38,265	36,525
Distribution lines spanning the province (circuit-kilometres)	123,441	123,361
Distribution customers (number of customers)	1,370,819	1,358,093
Rate base (millions of dollars)	7,852	7,389
Capital investments (millions of dollars)	577	588
Assets placed in-service (millions of dollars)	642	689

<sup>1</sup> 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).

**2018 Distribution Revenues**



**Other Business Segment**

Hydro One's other business segment consists of the Company's telecommunications business and certain corporate activities. The telecommunications business provides telecommunications support for the Company's transmission and distribution businesses, and also offers communications and information technology solutions to organizations with broadband network requirements utilizing Hydro One Telecom Inc.'s (Hydro One Telecom) fibre optic network to provide diverse, secure and highly reliable broadband connectivity. Hydro One's other business segment is not rate-regulated.

**PRIMARY FACTORS AFFECTING RESULTS OF OPERATIONS**

**Transmission Revenues**

Transmission revenues primarily consist of regulated transmission rates approved by the OEB which are charged based on the monthly peak electricity demand across Hydro One's high-voltage network. Transmission rates are designed to generate revenues necessary to construct, upgrade, extend and support a transmission system with sufficient capacity to accommodate maximum forecasted demand and a regulated return on the Company's investment. Peak electricity demand is primarily influenced by weather and economic conditions. Transmission revenues also include export revenues associated with transmitting electricity to markets outside of Ontario. Ancillary revenues include revenues from providing maintenance services to power generators and from third-party land use.

**Distribution Revenues**

Distribution revenues include regulated distribution rates approved by the OEB and amounts to recover the cost of purchased power used by the customers of the distribution business. Distribution rates are designed to generate revenues necessary to construct and support the local distribution system with sufficient capacity to accommodate existing and new customer demand and a regulated return on the Company's investment. Accordingly, distribution revenues are influenced by distribution rates, the cost of purchased power, and the amount of electricity the Company distributes. Distribution revenues also include ancillary distribution service revenues,

such as fees related to the joint use of Hydro One's distribution poles by the telecommunications and cable television industries, as well as miscellaneous revenues such as charges for late payments.

**Purchased Power Costs**

Purchased power costs are incurred by the distribution business and represent the cost of the electricity purchased by the Company for delivery to customers within Hydro One's distribution service territory. These costs are comprised of the following: the wholesale commodity cost of energy; the Global Adjustment, which is the difference between amounts the IESO pays energy producers for the electricity they produce and the actual fair market value of this electricity; and the wholesale market service and transmission charges levied by the IESO. Hydro One passes the cost of electricity that it delivers to its customers, and is therefore not exposed to wholesale electricity commodity price risk.

**Operation, Maintenance and Administration Costs**

OM&A costs are incurred to support the operation and maintenance of the transmission and distribution systems, and other costs such as property taxes related to transmission and distribution lines, stations and buildings and information technology (IT) systems. Transmission OM&A costs are incurred to sustain the Company's high-voltage transmission stations, lines, and rights-of-way, and include preventive and corrective maintenance costs related to power equipment, overhead transmission lines, transmission station sites, and forestry control to maintain safe distance between line spans and trees. Distribution OM&A costs are required to maintain the Company's low-voltage distribution system to provide safe and reliable electricity to the Company's residential, small business, commercial, and industrial customers across the province. These include costs related to distribution line clearing and forestry control to reduce power outages caused by trees, line maintenance and repair, land assessment and remediation, as well as issuing timely and accurate bills and responding to customer inquiries. Hydro One manages its costs through ongoing efficiency and productivity initiatives, while continuing to complete planned work programs associated with the development and maintenance of its transmission and distribution networks.

**Depreciation, 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, and gains and losses on interest rate swap agreements, contingent foreign exchange or other similar contracts, net of interest earned on short-term investments. A portion of financing charges incurred by the Company is capitalized to the cost of property, plant and equipment associated with the periods during which such assets are under construction before being placed in-service.

## RESULTS OF OPERATIONS

### Net Income (Loss)

Net loss attributable to common shareholders for the year ended December 31, 2018 of \$89 million is a decrease of \$747 million or 113.5% from the prior year. Significant influences on earnings included:

- increase in transmission and distribution revenues due to higher energy consumption resulting from favourable weather;
- higher transmission revenues driven by increased OEB-approved transmission rates;
- higher OM&A costs primarily resulting from:
  - higher vegetation management costs resulting from a change to an improved vegetation program resulting in greater coverage and better reliability,
  - higher property taxes, primarily due to non-recurring favourable re-assessment of payments in lieu of property taxes in 2017,
  - higher project write-offs due to revision of asset replacement strategies and alternatives not pursued, and obsolete inventory and technology, and
  - higher volume of demand maintenance work on power equipment and overhead lines; partially offset by
  - savings related to the renewed IT contract, and
- lower costs related to the proposed acquisition of Avista Corporation (Merger);
- higher financing charges primarily due to an increase in interest expense incurred on the convertible debentures and short-term notes payable, partially offset by revaluation of the foreign exchange contract related to the Merger; and
- higher income tax expense primarily attributable to a charge to deferred tax expense of \$799 million related to the OEB's deferred tax asset and distribution rates decisions, and higher before-tax earnings in 2018, partially offset by higher temporary differences arising from higher in-service additions in 2018, compared to 2017.

### EPS and Adjusted EPS

EPS was (\$0.15) in 2018, compared to \$1.11 in 2017. The decrease in EPS was driven by lower earnings in 2018, as discussed above. Adjusted EPS, which adjusts for income and costs related to the Merger, including gains and losses on the foreign exchange contract, as well as the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses, was \$1.35 in 2018, compared to \$1.17 in 2017. The increase in Adjusted EPS was driven by higher net income in 2018, as discussed above, but exclude the impact of items related to the Merger and the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses. See section "Non-GAAP Measures" for description of Adjusted EPS.

### Revenues

Year ended December 31 (millions of dollars, except as otherwise noted)

	2018	2017	Change
Transmission	1,686	1,578	6.8%
Distribution	4,422	4,366	1.3%
Other	42	46	(8.7%)
<b>Total revenues</b>	<b>6,150</b>	<b>5,990</b>	<b>2.7%</b>
Transmission	1,686	1,578	6.8%
Distribution, net of purchased power	1,523	1,491	2.1%
Other	42	46	(8.7%)
<b>Total revenues, net of purchased power</b>	<b>3,251</b>	<b>3,115</b>	<b>4.4%</b>
Transmission: Average monthly Ontario 60-minute peak demand (MW)	20,485	19,587	4.6%
Distribution: Electricity distributed to Hydro One customers (GWh)	27,338	25,876	5.7%

### Transmission Revenues

Transmission revenues increased by 6.8% in 2018 primarily due to the following:

- higher revenues driven by increased OEB-approved transmission rates for 2018;
- higher average monthly Ontario 60-minute peak demand driven by colder winter and warmer summer in 2018; and
- increased 2018 allowed return on equity (ROE) for the transmission business.

### Distribution Revenues, Net of Purchased Power

Distribution revenues, net of purchased power, increased by 2.1% in 2018 primarily due to the following:

- higher energy consumption resulting from favourable weather in 2018; partially offset by
- lower external revenues in 2018, mainly due to lower late payment charges, connection setup fees and lower storm restorations;
- lower Conservation and Demand Management (CDM) revenue; and
- lower deferred regulatory adjustments, mainly related to the pension cost differential account.

## Amended Management's Discussion and Analysis

### OM&A Costs

Year ended December 31 (millions of dollars)	2018	2017	Change
Transmission	409	375	9.1%
Distribution	602	593	1.5%
Other	94	98	(4.1%)
	1,105	1,066	3.7%

#### Transmission OM&A Costs

The increase of 9.1% in transmission OM&A costs for the year ended December 31, 2018 was primarily due to:

- a reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation in 2017;
- higher volume of work on vegetation management;
- higher project write-offs due to revision of asset replacement strategies and alternatives not pursued; and
- higher volume of demand maintenance work on power equipment and overhead lines; partially offset by
- lower costs related to the renewed IT contract.

#### Distribution OM&A Costs

The increase of 1.5% in distribution OM&A costs for the year ended December 31, 2018 was primarily due to:

- higher volume of work on vegetation management;
- higher volume of emergency calls; and
- higher project and inventory write-offs due to revision of asset replacement strategies, alternatives not pursued, and obsolete inventory and technology; partially offset by
- lower storm restoration costs;
- lower costs related to the renewed IT contract; and
- a lower volume of field collections and investigations as a result of extended winter moratorium.

#### Other OM&A Costs

The decrease in other OM&A costs for the year ended December 31, 2018 was driven by lower consulting and contract costs.

#### Depreciation, Amortization and Asset Removal Costs

The increase of \$20 million or 2.4% in depreciation, amortization and asset removal costs for 2018 was mainly due to the growth in capital assets as the Company continues to place new assets in-service, consistent with its ongoing capital investment program.

#### Financing Charges

The increase of \$20 million or 4.6% in financing charges for the year ended December 31, 2018 was primarily due to the following:

- a full year of elevated interest expense related to the convertible debentures issued in August 2017; and
- an increase in interest expense on short-term notes payable driven by higher weighted-average interest rates and balance of short-term notes outstanding in 2018; partially offset by
- a decrease in interest expense on long-term debt driven by lower weighted-average interest rate in 2018; and
- an unrealized gain recorded in 2018 due to revaluation of the foreign exchange contract related to the Merger.

#### Income Tax Expense

Income tax expense was \$915 million for the year ended December 31, 2018, compared to \$111 million in 2017. The Company realized an effective tax rate (ETR) of approximately 107.6% in 2018, compared to approximately 14.0% in 2017.

As prescribed by the regulators, the Company recovers income taxes and is required to accrue its tax expense based on the tax liability determined without accounting for temporary differences recoverable from or refundable to customers in the future. The increase in income tax expense for the year ended December 31, 2018 was primarily attributable to a charge to deferred tax expense of \$799 million related to the OEB's deferred tax asset and distribution rates decisions (see section "Regulation – Electricity Rates Applications – Hydro One Networks – Transmission" for details). Higher before-tax earnings for 2018, partially offset by increased temporary differences from higher in-service additions in 2018, also contributed to increased tax expense in 2018, compared to 2017.

## Amended Management's Discussion and Analysis

### Common Share Dividends

In 2018, 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 12, 2018	March 13, 2018	March 29, 2018	\$ 0.22	131
May 14, 2018	June 12, 2018	June 29, 2018	\$ 0.23	137
August 13, 2018	September 11, 2018	September 28, 2018	\$ 0.23	137
November 7, 2018	December 11, 2018	December 31, 2018	\$ 0.23	137
				542

Following the conclusion of the fourth quarter of 2018, 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 20, 2019	March 13, 2019	March 29, 2019	\$ 0.23	137

### SELECTED ANNUAL FINANCIAL STATISTICS

Year ended December 31 (millions of dollars, except per share amounts)

	2018	2017	2016
Revenues	6,150	5,990	6,552
Net income attributable to common shareholders	(89)	658	721
Basic EPS	\$ (0.15)	\$ 1.11	\$ 1.21
Diluted EPS	\$ (0.15)	\$ 1.10	\$ 1.21
Basic Adjusted EPS	\$ 1.35	\$ 1.17	\$ 1.21
Diluted Adjusted EPS	\$ 1.35	\$ 1.16	\$ 1.21
Dividends per common share declared	\$ 0.91	\$ 0.87	\$ 0.97 <sup>1</sup>
Dividends per preferred share declared	\$ 1.06	\$ 1.06	\$ 1.12

<sup>1</sup> The \$0.97 per share dividends declared in 2016 included \$0.13 for the post-Initial Public Offering (IPO) period from November 5 to December 31, 2015, and \$0.84 for the year ended December 31, 2016.

December 31 (millions of dollars)	2018	2017	2016
Total assets	25,657	25,701	25,351
Total non-current financial liabilities	10,479	9,815	10,084

### QUARTERLY RESULTS OF OPERATIONS

Quarter ended (millions of dollars, except EPS)	Dec 31, 2018	Sep 30, 2018	Jun 30, 2018	Mar 31, 2018	Dec 31, 2017	Sep 30, 2017	Jun 30, 2017	Mar 31, 2017
Revenues	1,491	1,606	1,477	1,576	1,439	1,522	1,371	1,658
Purchased power	741	733	674	751	662	675	649	889
Revenues, net of purchased power	750	873	803	825	777	847	722	769
Net income (loss) to common shareholders	(705)	194	200	222	155	219	117	167
Basic EPS	\$ (\$1.18)	\$ 0.33	\$ 0.34	\$ 0.37	\$ 0.26	\$ 0.37	\$ 0.20	\$ 0.28
Diluted EPS	\$ (\$1.18)	\$ 0.32	\$ 0.33	\$ 0.37	\$ 0.26	\$ 0.37	\$ 0.20	\$ 0.28
Basic Adjusted EPS <sup>1</sup>	\$ 0.30	\$ 0.38	\$ 0.33	\$ 0.35	\$ 0.29	\$ 0.40	\$ 0.20	\$ 0.28
Diluted Adjusted EPS <sup>1</sup>	\$ 0.29	\$ 0.38	\$ 0.32	\$ 0.35	\$ 0.28	\$ 0.40	\$ 0.20	\$ 0.28

<sup>1</sup> See section "Non-GAAP Measures" for description of Adjusted EPS.

Variations in revenues and net income over the quarters are primarily due to the impact of seasonal weather conditions on customer demand and market pricing, 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 year ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)	2018	2017	Change
Transmission	1,164	889	30.9%
Distribution	642	689	(6.8%)
Other	7	14	(50.0%)
<b>Total assets placed in-service</b>	<b>1,813</b>	<b>1,592</b>	<b>13.9%</b>

### Transmission Assets Placed In-Service

Transmission assets placed in-service increased by \$275 million or 30.9% during the year ended December 31, 2018 primarily due to the following:

- substantial completion of major development work at the Clarington transmission station;
- assets placed in-service in 2018 for station sustainment investments, including Horning, NRC, Centralia, London Nelson, St. Isidore, Wanstead, Mohawk, Palmerston, Chenaux, Dryden, and Bruce A transmission stations, as well as the Bruce Special Protection System end-of-life equipment replacement project;
- higher volume of demand work placed in-service associated with equipment failures;
- higher volume of spare transformers;
- higher volume of overhead lines and component replacement work placed in-service; and
- high volume of work on transmission facilities as a result of a wind storm; partially offset by
- assets placed in-service in 2017 for station sustainment investments, including OverBrook, Hanmer, Aylmer, Leaside, Richview, Goderich, Lakehead, Nepean, and Kirkland Lake transmission stations, as well as DeCew Falls and Hinchinbrooke switching stations;
- substantial investments in major development projects placed in-service in 2017, including the Leamington, Holland, Hawthorne, and Manby transmission stations;
- the completion of the Move-to-Mobile project in June 2017;
- lower volume of wood pole replacements; and
- lower volume of fleet and work equipment purchases.

### Distribution Assets Placed In-Service

Distribution assets placed in-service decreased by \$47 million or 6.8% during the year ended December 31, 2018 primarily due to the following:

- higher volume of sustainment lines carryover work in 2017;
- lower volume of distribution station refurbishments and spare transformer purchases;
- the completion of the Move-to-Mobile project in June 2017;
- lower volume of wood pole replacements;
- the completion of an operation center in Bolton in February 2017;
- lower volume of fleet and work equipment purchases;
- the completion of the Outage Response Management System project in the third quarter of 2017; and
- the completion of the Company's website redesign project in 2017 to improve customer service and operational efficiencies; partially offset by
- higher volume of emergency power and storm restorations work;
- cumulative investments in the Advanced Distribution System project in 2018;
- cumulative investments in distribution generation connection projects in 2018;
- cumulative investments placed in-service for the Source-to-Order Transformation project, which aims to modernize the Company's sourcing and procurement capabilities;
- increased investments placed in-service for meter sustainment work; and
- the completion of the Bill Redesign project, which included investments in application enhancements and software upgrades.

## Amended Management's Discussion and Analysis

### Capital Investments

The following table presents Hydro One's capital investments during the years ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)	2018	2017	Change
<b>Transmission</b>			
Sustaining	810	764	6.0%
Development	116	137	(15.3%)
Other	59	67	(11.9%)
	<b>985</b>	<b>968</b>	<b>1.8%</b>
<b>Distribution</b>			
Sustaining	296	280	5.7%
Development	217	227	(4.4%)
Other	64	81	(21.0%)
	<b>577</b>	<b>588</b>	<b>(1.9%)</b>
<b>Other</b>	<b>13</b>	<b>11</b>	<b>18.2%</b>
<b>Total capital investments</b>	<b>1,575</b>	<b>1,567</b>	<b>0.5%</b>

2018 capital investments of \$1,575 million were lower than the previously disclosed expected amount of \$1,660 million primarily due to:

- re-prioritization of distribution work resulting from the higher volume of storm restoration work, including lower volume of wood pole replacements, lines refurbishment work, distribution system capability projects, and transformer replacements; and
- delayed or deferred projects, including the Integrated System Operations Centre (new site and facility) deferred to future years, deferral of work to 2019 on North American Electric Reliability Corporation (NERC) projects, delays of work to 2019 on the underground cable circuit from Leaside to Main transmission stations, and on the Wanstead, Bronte and Seaton transmission stations; partially offset by
- unplanned work, including the recommencement of Niagara Reinforcement Project, Private Cloud Data Center project, Lake Superior Project, and Advanced Metering Infrastructure initiative; and
- higher volume of storm restoration work.

#### Transmission Capital Investments

Transmission capital investments increased by \$17 million or 1.8% during the year ended December 31, 2018. Principal impacts on the levels of capital investments included:

- higher volume of overhead lines refurbishments and replacements;
- higher volume of demand work associated with equipment failures;
- higher volume of spare transformer purchases;
- higher volume of work required to adhere to the NERC Critical Infrastructure Protection (Cyber Security) standards; and
- higher volume of IT upgrades and enhancements primarily related to the Private Cloud Data Center project in support of the modernization of Hydro One's IT infrastructure; partially offset by

- lower volume of transmission station refurbishments and replacements work;
- lower spend on load customer connections due to the completion of work at Leamington transmission station in 2017 and higher capital contributions received from customers in 2018;
- the completion of the Move-to-Mobile project in 2017;
- decreased investment in fleet and work equipment purchases as a result of fleet standardization and asset specification review; and
- lower volume of wood pole replacements.

#### Distribution Capital Investments

Distribution capital investments decreased by \$11 million or 1.9% during the year ended December 31, 2018. Principal impacts on the levels of capital investments included:

- lower volume of distribution lines and station refurbishments and replacements work;
- lower volume of wood pole replacements;
- decreased investment on fleet and work equipment purchases as a result of fleet standardization and asset specification review;
- lower volume of new connections and upgrades;
- lower spend on Advanced Distribution System infrastructures; and
- the completion of the Move-to-Mobile project in 2017; partially offset by
- increased volume of emergency power and storm restorations work due to higher storm activity in 2018;
- higher volume of IT upgrades and enhancements primarily related to the Private Cloud Data Center project in support of the modernization of Hydro One's IT infrastructure; and
- higher spend on joint-use and line relocation projects due to timing of capital contributions.

## Amended Management's Discussion and Analysis

### Major Transmission Capital Investment Projects

The following table summarizes the status of significant transmission projects as at December 31, 2018:

Project Name	Location	Type	Anticipated In-Service Date (year)	Estimated Cost (millions of dollars)	Capital Cost To Date
<b>Development Projects:</b>					
Supply to Essex County Transmission Reinforcement	Windsor-Essex area Southwestern Ontario	New transmission line and station	2018	56 <sup>1</sup>	54
Clarington Transmission Station	Oshawa area Southwestern Ontario	New transmission station	2018	240 <sup>1</sup>	238
Niagara Reinforcement Project	Niagara area Southwestern Ontario	New transmission line	2019	130	121
East-West Tie Station Expansion	Northern Ontario	New transmission connection and station expansion	2022	157	16
Northwest Bulk Transmission Line Development	Thunder Bay-Atikokan Northwestern Ontario	New transmission line	2024	35 <sup>2</sup>	1
<b>Sustainment Projects:</b>					
Richview Transmission Station Circuit Breaker Replacement	Toronto Southwestern Ontario	Station sustainment	2020	102	99
Bruce A Transmission Station	Tiverton Southwestern Ontario	Station sustainment	2020	138	123
Beck #2 Transmission Station Circuit Breaker Replacement	Niagara area Southwestern Ontario	Station sustainment	2022	113	65
Lennox Transmission Station Circuit Breaker Replacement	Napanee Southeastern Ontario	Station sustainment	2023	99	59

1 Major portions of the Supply to Essex County Transmission Reinforcement and Clarington Transmission Station projects were completed and placed in-service in 2018. Work on certain minor portions of the project continues in 2019.

2 The scope of the Northwest Bulk Transmission Line Development project, as specified by the IESO on October 24, 2018, is currently limited to the development phase only, reducing the estimated cost to \$35 million.

### Future Capital Investments

Following is a summary of estimated capital investments by Hydro One over the years 2019 to 2023. The Company's estimates are based on management's expectations of the amount of capital expenditures that will be required to provide transmission and distribution services that are efficient, reliable, and provide value for customers, consistent with the OEB's Renewed Regulatory Framework.

The 2019 transmission capital investments estimates differ from the prior year disclosures, representing a decrease to reflect Hydro One's recent one-year inflation-based application for 2019 transmission rates. The 2020 to 2022 transmission capital investments estimates are lower than the prior year disclosures as the Company has updated its plan for timing and pacing of future capital investments, as well as reprioritization of work. The projections and the timing of 2020-2023 expenditures are subject to approval by the OEB.

## Amended Management's Discussion and Analysis

The following table summarizes Hydro One's annual projected capital investments for 2019 to 2023, by business segment:

(millions of dollars)	2019	2020	2021	2022	2023
Transmission	1,049	1,203	1,329	1,380	1,381
Distribution	751	714	728	814	757
Other	13	15	26	9	10
<b>Total capital investments</b>	<b>1,813</b>	<b>1,932</b>	<b>2,083</b>	<b>2,203</b>	<b>2,148</b>

The following table summarizes Hydro One's annual projected capital investments for 2019 to 2023, by category:

(millions of dollars)	2019	2020	2021	2022	2023
Sustainment	1,148	1,211	1,467	1,574	1,530
Development	442	502	431	473	468
Other <sup>1</sup>	223	219	185	156	150
<b>Total capital investments</b>	<b>1,813</b>	<b>1,932</b>	<b>2,083</b>	<b>2,203</b>	<b>2,148</b>

<sup>1</sup> "Other" capital expenditures consist of special projects, such as those relating to IT.

### 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)	2018	2017
Cash provided by operating activities	1,575	1,716
Cash provided by (used in) financing activities	399	(201)
Cash used in investing activities	(1,516)	(1,540)
<b>Increase (decrease) in cash and cash equivalents</b>	<b>458</b>	<b>(25)</b>

#### Cash provided by operating activities

The decrease of \$141 million in cash from operating activities for the year ended December 31, 2018 compared to 2017 was impacted by various factors, including improved collection of accounts receivables in 2017 that reached a stabilized level in 2018, and disposition of certain regulatory variance and deferral accounts in 2018, partially offset by higher cash earnings in 2018.

#### Cash provided by financing activities

##### Sources of cash

- The Company issued long-term debt of \$1,400 million in 2018, compared to no long-term debt issued in 2017.
- The Company received proceeds of \$4,242 million from the issuance of short-term notes in 2018, compared to \$3,795 million received in 2017.
- In 2017, the Company received proceeds of \$513 million, representing the first instalment of the convertible debentures issued, gross of \$27 million financing costs, compared to no convertible debenture issuances in 2018.

##### Uses of cash

- The Company repaid \$3,916 million of short-term notes in 2018, compared to \$3,338 million repaid in 2017.
- The Company repaid \$753 million of long-term debt in 2018, compared to long-term debt of \$602 million repaid in 2017.
- Dividends paid in 2018 were \$560 million, consisting of \$542 million common share dividends and \$18 million of preferred share dividends, compared to dividends of \$536 million paid in 2017, consisting of \$518 million common share dividends and \$18 million of preferred share dividends.

#### Cash used in investing activities

##### Uses of cash

- Capital expenditures and future use asset purchases were lower in 2018, primarily due to lower volume and timing of capital investment work.

## 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 \$1.5 billion in short-term notes with a term to maturity of up to 365 days. At December 31, 2018, Hydro One Inc. had \$1,252 million in commercial paper borrowings outstanding, compared to \$926 million outstanding at December 31, 2017. The interest rates on the commercial paper borrowings outstanding at December 31, 2018 ranged from 1.9% to 2.3%. In addition, the Company has revolving bank credit facilities (Operating Credit Facilities) with total availability of \$2,550 million maturing in 2021 and 2022, with no amounts used at December 31, 2018 or 2017. The Company may use these credit facilities for working capital and general corporate purposes. On February 1, 2019, Hydro One entered into a credit agreement for a \$170 million unsecured demand operating credit facility (Demand Facility) for the purpose of funding the payment of the termination fee payable to Avista Corporation as a result of the termination of the Merger Agreement and other Merger related costs. The short-term liquidity under the commercial paper program, the Operating Credit Facilities, the Demand Facility and anticipated levels of FFO are expected to be sufficient to fund the Company's normal operating requirements.

At December 31, 2018, the Company had long-term debt outstanding in the principal amount of \$10,716 million which included \$10,573 million of long-term debt issued by Hydro One Inc. and long-term debt in the principal amount of \$143 million issued by HOSSM. The majority of long-term debt issued by Hydro One Inc. has been issued under its Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in March 2018 is \$4.0 billion. At December 31, 2018, \$2.6 billion remained available for issuance until April 2020. The long-term debt consists of notes and debentures that mature between 2019 and 2064, and at December 31, 2018, had a weighted-average term to maturity of approximately 16.3 years and a weighted-average coupon rate of 4.2%.

On June 18, 2018, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada to replace the universal base shelf prospectus that expired on April 30, 2018. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to \$4.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on July 18, 2020. On November 23, 2018, 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 for the purposes of, but not limited to, funding a portion of the cash purchase price of the Merger. The US Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, up to US\$3.0 billion of debt securities, unconditionally guaranteed by Hydro One, during the 25-month period ending on December 23, 2020. At December 31, 2018, no securities have been issued under the Universal Base Shelf Prospectus or the US Debt Shelf Prospectus.

## Acquisition Credit Facilities

For the purpose of bridge financing for the Merger, the Company secured a \$1.0 billion non-revolving equity bridge credit facility, and a US\$2.6 billion non-revolving debt bridge credit facility (Acquisition Credit Facilities) in June 2018. As a result of the termination of the Merger agreement (see Other Developments – Avista Corporation Purchase Agreement), on January 24, 2019, the Company cancelled the Acquisition Credit Facilities.

To mitigate the foreign currency risk related to the portion of the Merger purchase price financed by the issuance of convertible debentures, in October 2017, the Company entered into a deal-contingent foreign exchange forward contract to convert \$1.4 billion Canadian to US dollars. For the year ended December 31, 2018, an unrealized fair value gain of \$25 million was recorded related to this contract, compared to an unrealized fair value loss of \$3 million recorded for the year ended December 31, 2017. At December 31, 2018, the corresponding derivative asset was \$22 million, compared to a derivative liability of \$3 million at December 31, 2017. As a result of the termination of the Merger agreement (see Other Developments – Avista Corporation Purchase Agreement), no payment is due or receivable by Hydro One on the foreign exchange contract.

## Compliance

At December 31, 2018, 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 June 20, 2018, Moody's Investors Service (Moody's) downgraded the long-term debt rating for Hydro One Inc. to "Baa1" from "A3", and revised its outlook on Hydro One Inc. to stable from negative. In addition, Moody's affirmed the existing "Prime-2" short-term debt rating for Hydro One Inc. Moody's no longer assigns any probability of extraordinary support from the Province of Ontario (Province) in Hydro One Inc.'s credit analysis which has led to the downgrade.

## Amended Management’s Discussion and Analysis

On June 15, 2018, S&P Global Ratings (S&P) placed its ratings on the Company and Hydro One Inc. on CreditWatch negative reflecting the likelihood of a one-notch downgrade to both companies due to the Merger. On July 18, 2018, S&P released an update maintaining the CreditWatch negative placement, which continued to reflect the likelihood of a one-notch downgrade in the Company and Hydro One Inc.’s issuer credit rating of “A” due to the Merger, and also incorporated the possibility that the Company’s governance structure could result in an additional one-notch downgrade if S&P concludes that recent developments related to the retirement of the Company’s Chief Executive Officer (CEO) and the replacement of the Company’s Board of Directors (Board) adversely impact management decision making and fails to promote the interests of all stakeholders. See section “Hydro One Board of Directors and Executive Officers” for more information.

On September 13, 2018, S&P lowered its issuer credit ratings on the Company to “A-” from “A”. At the same time, S&P lowered the issue-level rating on Hydro One Inc.’s senior unsecured debt by one notch to “A-” from “A” and lowered the rating on Hydro One Inc.’s commercial paper program by one notch to “A-1 (low)” from “A-1 (mid)” on the Canadian National

At December 31, 2018, Hydro One’s corporate credit ratings were as follows:

Rating Agency	Corporate Credit Rating
S&P	A-

At December 31, 2018, Hydro One Inc.’s long-term and short-term debt ratings were as follows:

Rating Agency	Short-term Debt Rating	Long-term Debt Rating
DBRS Limited	R-1 (low)	A (high)
Moody’s	Prime-2	Baa1
S&P	A-1 (low)	A-

Hydro One has not obtained a credit rating in respect of any of its securities. An issuer rating from S&P is a forward-looking opinion about an obligor’s overall creditworthiness. This opinion focuses on the obligor’s capacity and willingness to meet its financial commitments as they come due but it does not apply to any specific financial obligation. An obligor with a long-term credit rating of ‘A’ has strong capacity to meet its financial commitments but is somewhat more susceptible to the adverse effects of changes in circumstances and economic conditions than obligors in higher-rated categories.

The rating above is not a recommendation to purchase, sell or hold any of Hydro One’s securities and does not comment on the market price or suitability of any of the securities for a particular investor. There can be no assurance that the rating will remain in effect for any given period of time or that the rating will not be revised or withdrawn entirely by S&P at any time in the future. Hydro One has made, and anticipates making, payments to S&P pursuant to agreements entered into with S&P in respect of the rating assigned to Hydro One and expects to make payments to S&P in the future to the extent it obtains a rating specific to any of its securities.

Scale. All ratings remained on CreditWatch where S&P placed them with negative implications on June 15, 2018. The one-notch downgrade reflected S&P’s reassessment of Hydro One’s management and governance structure, which according to S&P has weakened following the Province’s decision to exert its influence on the Company’s compensation structure through legislation, potentially promoting the interests and priorities of one owner above those of other stakeholders.

On December 10, 2018, S&P removed Hydro One’s ratings from CreditWatch with negative implications due to S&P’s revised assumption that the Merger was unlikely to close as expected, following the Washington Utilities and Transportation Commission (Washington UTC) decision on December 5, 2018 to deny the Merger. Also on this date, S&P placed the issuer credit rating on Hydro One and the issue-level rating on Hydro One Inc.’s senior unsecured debt on negative outlook due to uncertainty about Hydro One’s ability to convert its strategy into constructive actions that support the Company’s financial performance, broader concerns related to Hydro One’s governance, and uncertainty regarding the Company’s strategic direction.

### 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. 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 2018, Hydro One contributed approximately \$75 million to its pension plan, compared to contributions of approximately \$87 million in 2017, and incurred \$75 million in net periodic pension benefit costs, compared to \$88 million incurred in 2017.

In April 2018, Hydro One filed an actuarial valuation of its Pension Plan as at December 31, 2017. Based on this valuation and 2018 levels of pensionable earnings, the 2018 annual Company pension contributions of \$75 million were comparable to \$71 million as estimated at December 31, 2016. Hydro One estimates that total Company pension contributions for 2019, 2020, 2021, 2022, 2023 and 2024 are approximately \$78 million, \$77 million, \$78 million, \$79 million, \$81 million and \$83 million, respectively.

## Amended Management's Discussion and Analysis

The Company's pension benefits obligation is impacted by various assumptions and estimates, such as discount rate, rate of return on plan assets, rate of cost of living increase and mortality assumptions. A full discussion of the significant assumptions and estimates can be found in the section "Critical Accounting Estimates – Employee Future Benefits".

## OTHER OBLIGATIONS

### Off-Balance Sheet Arrangements

There are no off-balance sheet arrangements that have, or are reasonably likely to have, a material current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

### Summary of Contractual Obligations and Other Commercial Commitments

The following table presents a summary of Hydro One's debt and other major contractual obligations and commercial commitments:

December 31, 2018 (millions of dollars)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
<b>Contractual obligations (due by year)</b>					
Long-term debt – principal repayments	10,716	731	1,456	734	7,795
Long-term debt – interest payments	8,181	448	840	772	6,121
Convertible debentures – principal repayments <sup>1</sup>	513	—	—	—	513
Convertible debentures – interest payments <sup>1</sup>	539	62	123	123	231
Short-term notes payable	1,252	1,252	—	—	—
Pension contributions <sup>2</sup>	476	78	155	160	83
Environmental and asset retirement obligations	186	26	61	59	40
Outsourcing and other agreements	310	161	133	5	11
Operating lease commitments	28	7	15	2	4
Long-term software/meter agreement	39	17	18	3	1
<b>Total contractual obligations</b>	<b>22,240</b>	<b>2,782</b>	<b>2,801</b>	<b>1,858</b>	<b>14,799</b>
<b>Other commercial commitments (by year of expiry)</b>					
Operating Credit Facilities	2,550	—	250	2,300	—
Letters of credit <sup>3</sup>	182	182	—	—	—
Guarantees <sup>4</sup>	325	325	—	—	—
<b>Total other commercial commitments</b>	<b>3,057</b>	<b>507</b>	<b>250</b>	<b>2,300</b>	<b>—</b>

1 As a result of the termination of the Merger agreement (see Other Developments – Avista Corporation Purchase Agreement), on February 8, 2019, Hydro One redeemed the convertible debentures and paid the holders of the Instalment Receipts \$513 million plus accrued and unpaid interest of \$7 million.

2 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.

3 Letters of credit consist of a \$163 million letter of credit related to retirement compensation arrangements, a \$13 million letter of credit provided to the IESO for prudential support, \$5 million in letters of credit to satisfy debt service reserve requirements, and \$1 million in letters of credit for various operating purposes.

4 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

## 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 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 20, 2019, Hydro One had 595,940,880 issued and outstanding common shares.

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At February 20, 2019, two series of preferred shares are authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At February 20, 2019, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

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 20, 2019 is 6,231,715.

## Amended Management's Discussion and Analysis

### REGULATION

The OEB approves both the revenue requirements of and the rates charged by Hydro One's regulated transmission and distribution businesses. The rates are designed to permit the Company's transmission and distribution businesses to recover the allowed costs and to earn a formula-based annual

rate of return on its deemed 40% equity level invested in the regulated businesses. This is done by applying a specified equity risk premium to forecasted interest rates on long-term bonds. In addition, the OEB approves rate riders to allow for the recovery or disposition of specific regulatory deferral and variance accounts over specified time frames.

The following table summarizes the status of Hydro One's major regulatory proceedings with the OEB:

Application	Years	Type	Status
<b>Electricity Rates</b>			
Hydro One Networks	2017-2018	Transmission – Cost-of-service	OEB decision received <sup>1</sup>
Hydro One Networks	2019	Transmission – Revenue Cap	OEB decision pending
Hydro One Networks	2018-2022	Distribution – Custom	OEB decision received
B2M LP	2015-2019	Transmission – Cost-of-service	OEB decision received
HOSSM	2017-2026	Transmission – Revenue Cap	OEB decision received <sup>2</sup>
<b>Mergers Acquisitions Amalgamations and Divestitures (MAAD)</b>			
Orillia Power	n/a	Acquisition	OEB decision pending <sup>3</sup>
Peterborough Distribution	n/a	Acquisition	OEB decision pending
<b>Leave to Construct</b>			
East-West Tie Station Expansion	n/a	Section 92	OEB decision received
Lake Superior Link Project	n/a	Section 92	OEB decision received <sup>4</sup>

1 On March 7, 2019, the OEB upheld its Original Decision relating to the deferred tax asset. The Company is currently considering its options under the Appeal.

2 In October 2016, the OEB approved the 2017-2026 revenue requirements. In July 2018, HOSSM filed an application for an inflationary increase (Revenue Cap Escalator factor) to its 2019 revenue requirement.

3 In September 2018, Hydro One filed a new MAAD application with the OEB to acquire Orillia Power.

4 On February 11, 2019, the OEB issued its decision awarding the construction of the East-West Tie Line to NextBridge, as directed by the Province on January 30, 2019.

The following table summarizes the key elements and status of Hydro One's electricity rate applications:

Application	Year	ROE Allowed (A) or Forecast (F)	Rate Base Allowed (A) or Forecast (F)	Rate Application Status	Rate Order Status
<b>Transmission</b>					
Hydro One Networks	2018	9.00% (A)	\$11,148 million (A)	Approved in September 2017	Approved in December 2017
	2019	n/a <sup>1</sup>	n/a <sup>1</sup>	Filed in October 2018	To be filed
B2M LP	2018	9.00% (A)	\$502 million (A)	Approved in December 2015	OEB decision received
	2019	8.98% (A)	\$496 million (A)	Approved in December 2015	Approved in December 2018
HOSSM	2017-2026	9.19% (A)	\$218 million (A)	Approved in October 2016	OEB decision received <sup>2</sup>
<b>Distribution</b>					
Hydro One Networks	2018	9.00% (A)	\$7,650 million (F)	Filed in March 2017 <sup>3</sup>	To be filed in 2019 Q1
	2019	8.98% (A)	\$8,009 million (F)	Filed in March 2017 <sup>3</sup>	To be filed in 2019 Q1
	2020	8.98% (F)	\$8,412 million (F)	Filed in March 2017 <sup>3</sup>	To be filed in 2019 Q4
	2021	8.98% (F)	\$8,941 million (F)	Filed in March 2017 <sup>3</sup>	To be filed in 2020 Q4
	2022	8.98% (F)	\$9,306 million (F)	Filed in March 2017 <sup>3</sup>	To be filed in 2021 Q4

1 The Revenue Cap application is a formulaic adjustment to the approved revenue requirement and does not consider ROE or rate base.

2 In October 2016, the OEB approved the 2017-2026 revenue requirements. In July 2018, HOSSM filed an application for an inflationary increase (Revenue Cap Escalator factor) to its 2019 revenue requirement.

3 In June 2018, Hydro One Networks filed an undertaking with the OEB which included updated rate base amounts.

### Electricity Rates Applications

#### Hydro One Networks – Transmission

On September 28, 2017, the OEB issued its decision and order on Hydro One Networks' 2017 and 2018 transmission rates revenue requirements (Original Decision), with 2017 rates effective January 1, 2017. Key changes to the application as filed included reductions in planned capital expenditures of \$126 million and \$122 million for 2017 and 2018, respectively, reductions in OM&A expenses related to compensation by \$15 million for each year, and reductions in estimated tax savings from the IPO by \$24 million and \$26 million for 2017 and 2018, respectively. On October 10, 2017, Hydro One Networks filed a Draft Rate Order reflecting the changes outlined in the 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 (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 result in an impairment of a portion of Hydro One Networks' transmission deferred income tax regulatory asset. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, it would also result in an additional impairment of a portion of Hydro One Networks' 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 Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. 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 Decision relating to the deferred tax asset to an OEB panel for reconsideration.

Subsequent to year end, 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 of this subsequent event that requires adjustment in the 2018 financial statements, the Company has recognized an impairment charge of Hydro One Networks' distribution deferred income tax regulatory asset of \$474 million and Hydro One Networks' transmission deferred income tax regulatory asset of \$558 million, an increase in deferred income tax regulatory liability of \$81 million, and a decrease in the forgone revenue deferral regulatory asset of \$68 million. After recognition of the related \$314 million deferred tax asset, the Company has recorded an \$867 million one-time decrease in net income as a reversal of revenues of \$68 million, and charge to deferred tax expense of \$799 million, which is expected to result in an annual decrease to FFO in the range of \$50 million to \$60 million. Notwithstanding the recognition of the effects of the decision in the financial statements, the Company is currently considering its options under the Appeal.

See section "Risk Management and Risk Factors - Risks Relating to Hydro One's Business - Risks Relating to Regulatory Treatment of Deferred Tax Asset" for description of related risks.

On November 23, 2017, the OEB approved the 2017 transmission revenue requirement of \$1,438 million. In December 2017, the OEB approved the 2018 transmission revenue requirement of \$1,511 million, which included a \$25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

On November 23, 2017, the OEB approved the 2017 transmission revenue requirement of \$1,438 million. In December 2017, the OEB approved the 2018 transmission revenue requirement of \$1,511 million, which included a \$25 million increase from the approved amount, as a result of the OEB-updated cost of capital parameters. Uniform Transmission Rates (UTRs), reflecting these approved amounts, were approved by the OEB on February 1, 2018 to be effective as of January 1, 2018.

On March 16, 2018, the OEB issued a letter requesting Hydro One to file the transmission revenue requirement application for a four-year test period from 2019 to 2022, rather than the minimum 5-year period allowed under existing OEB policy. The OEB indicated that it is more appropriate to consider rates for Hydro One's distribution and transmission businesses in a single application, and stated that it expected Hydro One to file a single application for distribution rates (including Hydro One Remote Communities) and transmission revenue requirement for the period from 2023 to 2027.

A one-year inflation-based application for 2019 transmission rates was filed with the OEB on October 26, 2018. On December 20, 2018, the OEB issued a decision declaring Hydro One's revenue requirement and the UTRs for 2019 as interim.

#### Hydro One Networks – Distribution

On March 31, 2017, Hydro One Networks filed a custom application with the OEB for 2018-2022 distribution rates under the OEB's incentive-based regulatory framework (2018-2022 Distribution Application), which was subsequently updated on June 7 and December 21, 2017. The application reflects the level of capital investments required to minimize degradation in overall system asset condition, to meet regulatory requirements, and to maintain current reliability levels.

The OEB oral hearing related to Hydro One Networks' application for 2018-2022 distribution rates was held on June 11-28, 2018. On August 31, 2018, Hydro One submitted its final argument. Subsequently, steps were taken to address the outstanding issues related to pole attachment fees and matters relating to recovery of certain amounts paid for executive compensation, as per the *Hydro One Accountability Act* (Accountability Act). See section "Hydro One Board of Directors and Executive Officers" for more information. On December 6, 2018, Hydro One made its final submission on matters relating to the Accountability Act and the impact on revenue requirement. Regarding the pole attachment fees, after following the process outlined by the OEB, Hydro One proposed the use of the province-wide pole attachment rate, effective January 1, 2019. On November 15, 2018, the OEB accepted the proposal. On March 7, 2019, the OEB issued its decision for Hydro One Networks' 2018-2022 distribution rates. See above in "Hydro One Networks – Transmission" for impacts relating to the distribution deferred income tax regulatory asset.

## Amended Management's Discussion and Analysis

On June 27, 2018, the OEB issued a letter deferring Hydro One's request for the OEB to approve an alternative method to calculate amounts related to the post-employment benefit costs for Hydro One Networks' distribution business until the next re-basing application is filed, as the OEB noted that the issue is relevant to both the distribution and transmission businesses of Hydro One Networks. In the 2019 transmission rates application filed with the OEB on October 26, 2018, Hydro One requested this decision be made as part of its next transmission re-basing application.

### B2M LP

In December 2015, the OEB approved B2M LP's revenue requirement for years 2015 to 2019, subject to annual updates in each of 2016, 2017, 2018 and 2019 to adjust its revenue requirement for the following year consistent with the OEB's updated cost of capital parameters. On May 10, 2018, the OEB issued its Decision and Rate Order on B2M LP's 2018 transmission application reflecting revenue requirement of \$36 million, effective January 1, 2018.

On November 23, 2018, a revised 2019 revenue requirement using the updated cost of capital parameters was filed with the OEB. On December 20, 2018, the OEB issued its Decision on UTRs effective January 1, 2019, approving the requested 2019 revenue requirement of \$33 million.

### HOSSM

HOSSM is under a 10-year deferred rebasing period for years 2017-2026, as approved in the OEB MAAD decision dated October 13, 2016. On July 26, 2018, HOSSM filed a 2019 application to allow for inflationary increase (Revenue Cap Escalator factor) to its previously approved revenue requirement. The Revenue Cap Escalator factor is designed to add inflationary increases to the revenue requirement on an annual basis. The proceeding continues and an OEB decision is expected in the second quarter of 2019.

### Hydro One Remote Communities

On August 28, 2017, Hydro One Remote Communities filed an application with the OEB seeking approval of its 2018 revenue requirement of \$57 million and electricity rates effective May 1, 2018. On March 19, 2018, the OEB approved the settlement agreement related to the 2018 rates application reached by Hydro One Remote Communities and the intervenors in the rate proceeding. On March 26, 2018, a draft rate order was filed with the OEB for 2018 rates. The OEB approved the draft rate order on April 12, 2018, and the new rates were implemented effective May 1, 2018.

On November 5, 2018, Hydro One Remote Communities filed an application with the OEB seeking approval for increased base rates of 1.8% effective May 1, 2019. On February 11, 2019, the OEB issued a draft decision approving the requested increase.

Hydro One Remote Communities is fully financed by debt and is operated as a break-even entity with no ROE.

### Niagara Reinforcement Limited Partnership (NRLP)

On September 19, 2018, NRLP was formed to own and operate a new 230 kV transmission line in the Niagara region that will enable generators in the Niagara area to connect to the load centres of the Greater Toronto and Hamilton areas. NRLP is designed to include minority participation of local First Nations partners in a structure similar to B2M LP.

On September 27, 2018, Hydro One filed a transmission licence application with the OEB for NRLP. On October 25, 2018, Hydro One filed two other applications with the OEB relating to NRLP requesting approval for Hydro One Networks to sell the applicable assets to NRLP and approval of interim rates to include in the 2019 UTRs. On December 20, 2018, the OEB issued a decision finding that the request for approval for an interim revenue requirement effective January 1, 2019 was premature but indicated that there would be an opportunity to adjudicate the matter at a later date. NRLP expects the OEB to decide on this application later in 2019.

## MAAD Applications

### Orillia Power MAAD Application

In 2016, Hydro One filed a MAAD application (2016 Application) with the OEB to acquire Orillia Power Distribution Corporation (Orillia Power) from the City of Orillia, Ontario. On April 12, 2018, the OEB issued a decision denying Hydro One's proposed acquisition of Orillia Power. The decision indicated that with the exception to pricing, the transaction met the no harm test. Additionally, the OEB indicated that it required additional evidence on the overall cost structure following the deferral period and the impact on Orillia Power's customers. On May 2, 2018, Hydro One and Orillia Power both filed a Motion to Review and Vary the OEB's decision, and on August 23, 2018, the OEB issued a decision upholding its April 12, 2018 decision to deny Hydro One's proposed acquisition of Orillia Power.

On September 26, 2018, Hydro One filed a new MAAD application (2018 Application) with the OEB to acquire Orillia Power. The evidence in the 2018 Application is similar to that provided in the 2016 Application. However it includes additional information that was not available at the time Hydro One filed its 2016 MAAD Application, including updates to reflect current variables to costs and other metrics, as well as future cost structures pertaining to the acquired entity.

On October 16, 2018, the School Energy Coalition (SEC) filed a motion with the OEB seeking an order dismissing the 2018 Application. On January 16, 2019, Hydro One and Orillia Power filed submissions on the SEC motion, maintaining that the motion should be dismissed, and the 2018 Application should be heard by the OEB. A decision by the OEB is pending.

### Peterborough Distribution MAAD Application

On October 12, 2018, the Company filed an application with the OEB for approval of the acquisition of business and distribution assets of Peterborough Distribution Inc. (Peterborough Distribution). On October 25, 2018, an advance ruling certification application was filed with the Competition Bureau. On November 14, 2018, the Competition Bureau issued no action letter, meaning that transaction can proceed from the Competition Bureau's perspective. The decision of the OEB is still pending. See section "Other Developments – Peterborough Distribution Purchase Agreement" for more information on the acquisition.

## Other Applications

### East-West Tie / Lake Superior Link

On February 15, 2018, Hydro One filed a Leave to Construct application with the OEB to construct a transmission line (East-West Tie Line) in northwestern Ontario (Lake Superior Link Project), which competed with an application filed by NextBridge to construct the East-West Tie Line. Pursuant to the OEB's direction, on July 26, 2018, the IESO issued its analysis of the

impacts of a delay to the in-service date for the construction of the East-West Tie Line. In its analysis, the IESO recommends an in-service date of 2020 for the completion of the East-West Tie Line and does not support a delay beyond 2022, due to increased risks to system reliability and the associated cost uncertainties.

A combined OEB oral hearing for the Hydro One Lake Superior Link Project application, the Hydro One East-West Tie Station Expansion application, and the NextBridge East-West Tie Line application was held in October 2018. On December 20, 2018, the OEB approved Hydro One's East-West Tie Station Expansion application. However, with respect to approval for the Lake Superior Link Project, the OEB decided to add a further step requesting both Hydro One and NextBridge to submit a final not-to-exceed price by January 31, 2019, noting that price will be the deciding factor.

On January 18, 2019, BLP First Nations (BLP) filed a Notice of Appeal to Divisional Court appealing the OEB's December decision, asserting that the OEB decision lacks consideration and application of duty to consult in section 35 of the *Constitution Act, 1982*. On the same date, NextBridge filed a Notice of Appeal to Divisional Court appealing portions of the OEB's December decision that relate to transferring information attained in the environmental assessment process to Hydro One and the disallowance of recovery of a portion of NextBridge's development work. On January 30, 2019, the Minister of Energy, Northern Development and Mines, issued a directive to the OEB to amend NextBridge's electricity transmission licence and allow it to proceed with the East-West Tie transmission line, effectively ending Hydro One's competitive bid to build the Lake Superior Link Project. On February 11, 2019, the OEB issued its decision awarding the construction of the East-West Tie Line to NextBridge. As a result, in the first quarter of 2019, Hydro One recognized an impairment loss of approximately \$11 million associated with previously capitalized costs related to this project.

## OTHER DEVELOPMENTS

### Exemptive Relief

#### Disclosure of Ownership by the Province

On June 6, 2017, the Canadian securities regulatory authorities granted (i) the Minister of Energy, (ii) Ontario Power Generation Inc. (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.

### Litigation

#### Class Action Lawsuit

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to \$125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal.

#### Litigation Relating to the Merger

To date, four putative class action lawsuits were filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the Merger has closed. Counsel for the plaintiffs in *Fink* has informally indicated that, in light of the termination of the Merger, the lawsuit will be dismissed, but no formal dismissal papers have been filed with the court at this time. Second, *Jenß v. Avista Corp., et al.*, *Samuel v. Avista Corp., et al.*, and *Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß*, *Samuel*, and *Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants.

#### Peterborough Distribution Purchase Agreement

On July 31, 2018, Hydro One reached an agreement to acquire the business and distribution assets of Peterborough Distribution, an electricity distribution company located in east central Ontario, from the City of Peterborough. Hydro One will pay the City of Peterborough \$105 million for the transaction. The acquisition is conditional upon the satisfaction of customary closing conditions and approval by the OEB and the Competition Bureau. On October 12, 2018, the Company filed an application with the OEB

## Amended Management's Discussion and Analysis

for approval of the acquisition. On November 14, 2018, the Competition Bureau issued no action letter, meaning that transaction can proceed from the Competition Bureau's perspective. The decision of the OEB is still pending.

### Avista Corporation Purchase Agreement

In July 2017, Hydro One reached an agreement to acquire Avista Corporation. The completion of the Merger was subject to receipt of certain regulatory and governmental approvals, including the expiration or termination of any applicable waiting period under the *Hart-Scott-Rodino Antitrust Improvements Act of 1976*, clearance of the Merger by the Committee on Foreign Investment in the United States, the approval by each of the Regulatory Commission of Alaska, the Washington UTC, the Idaho Public Utilities Commission (Idaho PUC), Oregon Public Utility Commission (Oregon PUC), the Public Service Commission of the State of Montana, the United States Federal Energy Regulatory Commission and the United States Federal Communications Commission, and the satisfaction or waiver of certain closing conditions contained in the Merger Agreement.

Following the announcement on July 11, 2018 of the resignation of Hydro One's Board and the immediate retirement of its President and CEO (see section "Hydro One Board of Directors and Executive Officers" for more information), regulatory authorities in Washington and Oregon extended the timetable for arriving at a decision in Hydro One's proposed acquisition of Avista Corporation to mid-December 2018. In addition, the Idaho PUC rescheduled its hearing from July 23, 2018 to November 26-27, 2018. The Idaho PUC denied approval of the merger on January 3, 2019. The Washington UTC denied approval of the merger on December 5, 2018. On December 17, 2018, Hydro One and Avista Corporation filed a petition for reconsideration and a petition for a rehearing with the Washington UTC. On January 8, 2019, the Washington UTC gave notice of the deemed denial by operation of law (effective January 7, 2019) of the petition for reconsideration filed by Hydro One and Avista Corporation. In the same notice, the Washington UTC also denied the petition for a rehearing on the basis that it is moot because of the deemed denial of the petition for reconsideration. In light of the decisions by the Washington UTC and the Idaho PUC to deny approval of the Merger, the Oregon PUC issued an order on January 14, 2019 suspending indefinitely the current procedural schedule in its Merger docket until Hydro One and Avista Corporation inform the Oregon PUC that they have sought a reversal of the denial decisions through appeal or other means that would provide a justiciable issue for the Oregon PUC to address.

On January 23, 2019, Hydro One and Avista Corporation announced that the companies have mutually agreed to terminate the Merger agreement. As a result of the termination of the Merger agreement, on January 24, 2019, Hydro One paid a US\$103 million termination fee to Avista Corporation as required by the Merger agreement. On January 24, 2019, the Company cancelled the Acquisition Credit Facilities, with no amounts drawn. On February 1, 2019, Hydro One entered into the Demand Facility for the purpose of funding the payment of the termination fee and other Merger

related costs. On February 8, 2019, Hydro One redeemed the convertible debentures and paid the holders of the Instalment Receipts \$513 million (\$333 per \$1,000 principal amount) plus accrued and unpaid interest of \$7 million. The redemption of the convertible debentures was paid with cash on hand. As a result of the termination of the Merger agreement, no payment is due or receivable by Hydro One on the foreign exchange contract.

The following amounts related to the termination of the Merger agreement will be recorded by the Company in its 2019 first quarter financial statements:

- approximately \$138 million OM&A costs for payment of the US\$103 million termination fee;
- \$22 million financing charges, due to revaluation of the foreign-exchange contract to \$nil and reversal of previously recorded gains;
- repayment of \$513 million convertible debentures and 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

### Directors and Executive Officers

On July 11, 2018, Hydro One, on behalf of itself and its wholly-owned subsidiary, Hydro One Inc., announced that it had entered into an agreement (Letter Agreement) with the Province for the purpose of the orderly replacement of the Board of Hydro One and Hydro One Inc. and the retirement of Mayo Schmidt as the CEO effective July 11, 2018. Hydro One also announced the appointment of Paul Dobson as Acting President and CEO of Hydro One and Hydro One Inc. effective July 11, 2018.

On August 14, 2018, Hydro One announced a new Board. Six directors were identified and nominated by an ad hoc nominating committee, comprised of three of the five largest shareholders of Hydro One excluding the Province, and four directors were identified and nominated by the Province, Hydro One's largest shareholder. Each of the directors is independent of both Hydro One and the Province in accordance with the Governance Agreement dated as of November 5, 2015 between Hydro One and the Province (Governance Agreement).

The directors of Hydro One and Hydro One Inc. are the same in accordance with the provisions of the Governance Agreement.

On September 7, 2018, Hydro One announced the appointment of Chris Lopez as Acting Chief Financial Officer (CFO) of Hydro One and Hydro One Inc., effective September 6, 2018. On September 7, 2018, Hydro One announced the appointment of Tom Woods as Chair of the Board of Hydro One and Hydro One Inc., effective September 6, 2018. Patrick Meneley, Executive Vice President and Chief Corporate Development Officer has advised the Company of his decision to leave Hydro One effective March 1, 2019.

## Amended Management's Discussion and Analysis

The following table sets forth information regarding the current directors and executive officers of Hydro One and Hydro One Inc. as at December 31, 2018. Each of the directors was first appointed effective August 14, 2018. Each director is elected annually to serve for one year or until his or her successor is elected or appointed.

Name, Province or State and Country of Residence	Age	Position/Title	Independent Board Member	Principal Occupation	Committees
Paul Dobson Texas, USA	52	Acting President and CEO		Acting President and CEO	
Jason Fitzsimmons Ontario, Canada	48	Chief Corporate Affairs and Customer Care Officer		Chief Corporate Affairs and Customer Care Officer	
Gregory Kiraly Arizona, USA	54	Chief Operating Officer		Chief Operating Officer	
Chris Lopez Alberta, Canada	44	Acting CFO		Acting CFO	
Judy McKellar Ontario, Canada	62	Executive Vice President, Chief Human Resources Officer		Executive Vice President, Chief Human Resources Officer	
Patrick Meneley Ontario, Canada	55	Executive Vice President and Chief Corporate Development Officer		Executive Vice President and Chief Corporate Development Officer	
James Scarlett Ontario, Canada	65	Executive Vice President and Chief Legal Officer		Executive Vice President and Chief Legal Officer	
Tom Woods <sup>1</sup> Ontario, Canada	66	Director and Chair of the Board	Yes	Director	
Cherie Brant <sup>1</sup> Ontario, Canada	44	Director	Yes	Partner, Dickinson Wright LLP	Governance Committee; Health, Safety, Environment and Indigenous Peoples Committee
Blair Cowper-Smith <sup>1</sup> Ontario, Canada	70	Director	Yes	Director	Governance Committee (Chair); Human Resources Committee
Anne Giardini British Columbia, Canada	59	Director	Yes	Director	Audit Committee; Health, Safety, Environment and Indigenous Peoples Committee (Chair)
David Hay New Brunswick, Canada	63	Director	Yes	Managing Partner, Delgatie Incorporated	Audit Committee; Health, Safety, Environment and Indigenous Peoples Committee
Timothy Hodgson Ontario, Canada	58	Director	Yes	Managing Partner and Director, Alignvest Management Corporation	Governance Committee; Human Resources Committee
Jessica McDonald British Columbia, Canada	49	Director	Yes	Interim President and CEO, Canada Post Corporation	Audit Committee; Human Resources Committee
Russel Robertson <sup>1</sup> Ontario, Canada	71	Director	Yes	Director	Audit Committee; Human Resources Committee
William Sheffield Ontario, Canada	70	Director	Yes	Director	Audit Committee (Chair); Health, Safety, Environment and Indigenous Peoples Committee
Melissa Sonberg Québec, Canada	58	Director	Yes	Adjunct Professor, McGill University	Governance Committee; Human Resources Committee (Chair)

<sup>1</sup> These directors have been designated as the Province's nominees to the Board of Hydro One for the purpose of the Governance Agreement.

## Amended Management's Discussion and Analysis

The following includes a brief profile of each of the executive officers and directors of Hydro One and Hydro One Inc., which includes a description of their present occupation and their principal occupations for the past five years:

### **Paul Dobson – Acting President and CEO**

Effective July 11, 2018, Paul Dobson was appointed to the role of Acting President and CEO of Hydro One. Mr. Dobson joined the Company as CFO on March 1, 2018 responsible for finance, treasury, controller, internal audit, technology and regulation. Prior to joining Hydro One in 2018, Mr. Dobson served as CFO for Direct Energy Ltd. (Direct Energy), Houston, Texas, where he was responsible for overall financial leadership of a \$15 billion revenue business with three million customers in Canada and the US. Since 2003, Mr. Dobson has held senior leadership positions in finance, operations, IT and customer service across the Centrica Group, the parent company of Direct Energy. Prior to Direct Energy, Mr. Dobson worked at CIBC for 10 years in finance, strategy and business development roles in both Canada and the US. Mr. Dobson also brings considerable experience in mergers and acquisitions and integrating acquired companies across North America and in the United Kingdom. Mr. Dobson is a dual Canadian-US citizen who holds an honours bachelor's degree from the University of Waterloo as well as a Masters of Business Administration (MBA) from the University of Western Ontario and is a CPA, CMA.

### **Jason Fitzsimmons – Chief Corporate Affairs and Customer Care Officer**

Jason Fitzsimmons was promoted to Chief Corporate Affairs and Customer Care Officer in August 2018, with oversight of the customer service, corporate affairs, marketing and Indigenous relations functions. With more than 25 years of experience in the electricity sector, Mr. Fitzsimmons is a highly-regarded leader with a proven track record for successfully executing large-scale transformations and building strong relationships with key stakeholders. In his previous role as Vice President, Labour Relations at Hydro One, Mr. Fitzsimmons played an instrumental role in bringing the company's 400-employee Customer Contact Centre in-house as the Company continuously strives to deliver best-in-class customer service. Prior to joining the Company in 2016, Mr. Fitzsimmons was the Chief Negotiations Officer at the Ontario Hospital Association and also held a number of executive roles at OPG, including Vice President of Human Resources for the Nuclear division. He is a Certified Human Resource Executive known for his broad experience in labour management as well as his passion for health and safety in the workplace. He was a prior member of the Advisory Board for Ryerson University's Centre for Labour Management Relations and has served on the Board for the Electrical Power Sector Construction Association.

### **Gregory Kiraly – Chief Operating Officer**

Effective September 12, 2016, Gregory Kiraly was appointed to the role of Chief Operating Officer (COO) of Hydro One. As COO, Mr. Kiraly oversees the complete transmission and distribution value chain including planning, engineering, construction, operations, maintenance,

and forestry; shared services functions including facilities, real estate, fleet, and procurement; and the Hydro One Telecom and Hydro One Remote Communities subsidiaries. Prior to joining Hydro One in 2016, Mr. Kiraly served as Senior Vice President of Electric Transmission and Distribution at Pacific Gas and Electric Company (PG&E) in San Francisco, which delivers safe and reliable energy to more than 16 million customers in northern and central California. Since joining PG&E in 2008, Mr. Kiraly led efforts that achieved the lowest employee injury rates ever, seven straight years of record electric reliability, and over \$500 million in productivity improvements and efficiency savings. Before PG&E, Mr. Kiraly held executive-level positions in energy delivery at Commonwealth Edison (Exelon) in Chicago and leadership positions in both gas and electric distribution at Public Service Electric and Gas Company in Newark, New Jersey. Mr. Kiraly holds a bachelor's degree in industrial engineering from New Jersey Institute of Technology and an MBA in finance from Seton Hall University. He is also a graduate of Harvard University's Advanced Management Program.

### **Chris Lopez – Acting CFO**

Effective September 6, 2018, Chris Lopez was appointed as Acting CFO for Hydro One. As Acting CFO, Mr. Lopez is responsible for corporate finance (including treasury and tax), internal audit, investor relations, and pensions. Mr. Lopez joined Hydro One on November 14, 2016 when he was appointed as Senior Vice President of Finance, bringing almost 17 years of progressive experience in the utilities industry in Canada and Australia. Prior to joining Hydro One, Mr. Lopez was the Vice President, Corporate Planning and Mergers & Acquisitions at TransAlta Corporation from 2011 to 2015. Prior to that, Mr. Lopez was Director of Operations Finance at TransAlta in Calgary from 2007 to 2011, and he held senior financial roles up to and including Country Financial Controller for TransAlta in Australia, from 1999 to 2007. Mr. Lopez worked as a Senior Financial Accountant with Rio Tinto Iron Ore, in Australia from 1997 to 1999. Mr. Lopez received a Bachelor of Business degree from Edith Cowan University in 1996, and a Chartered Accountant designation in Australia in 1999. He received a graduate diploma in corporate governance and directorships from the Australian Institute of Company Directors in 2007.

### **Judy McKellar – Executive Vice President, Chief Human Resources Officer**

Judy McKellar is the Executive Vice President, Chief Human Resources Officer of Hydro One. She was appointed to this position on November 11, 2016. Ms. McKellar has held various roles of increasing responsibility at Hydro One Networks, an indirect subsidiary of Hydro One, in the Human Resources department over her 30+ year career and was appointed Vice President of Human Resources in 2010. In 2014, she assumed the additional responsibility of Senior Vice President of People and Culture/Health, Safety and Environment and serves as the accountable executive for the Human Resources Committee of the Board. Ms. McKellar earned a Bachelor of Arts degree from Victoria College, University of Toronto, and was recently named as one of 2015's 100 Most Powerful Women in Canada by PricewaterhouseCoopers in the "Public Sector" category.

### **Patrick Meneley – Executive Vice President and Chief Corporate Development Officer**

Effective March 1, 2018, Patrick Meneley was appointed to the role of Executive Vice President and Chief Corporate Development Officer of Hydro One. In this capacity, Mr. Meneley is responsible for leading strategy, innovation and mergers and acquisitions. Prior to joining Hydro One in 2018, Mr. Meneley served as Executive Vice President, Wholesale Banking at TD Bank Group and Vice Chair and Head of Global Corporate and Investment Banking for TD Securities. Mr. Meneley spent 15 years leading and building one of the leading corporate and investment banking businesses in Canada, along with a profitable and growing franchise in the US. Mr. Meneley holds an MBA (with distinction) from the University of Western Ontario and a Bachelor of Commerce (with honours) from the University of British Columbia.

### **James Scarlett – Executive Vice President and Chief Legal Officer**

Effective September 1, 2016, James Scarlett was appointed as Executive Vice President and Chief Legal Officer of Hydro One. Prior to joining Hydro One, Mr. Scarlett was a Senior Partner at Torys LLP. He joined Torys LLP in March 2000 and held a number of leadership roles at the firm, including head of Torys LLP's Capital Markets Group, Mining Group and International Business Development Strategy. Mr. Scarlett was also a member of the firm's Executive Committee from 2009-2015. Prior to joining Torys LLP, Mr. Scarlett was a Partner at another major Canadian law firm. While at that firm Mr. Scarlett held leadership roles as head of its Corporate Group, Securities Group and as a member of its Board. Mr. Scarlett was also seconded to the Ontario Securities Commission in 1987 and was appointed as the first Director of Capital Markets in 1988, a position he held until his return to private law practice in 1990. Mr. Scarlett earned his law degree (J.D.) from the University of Toronto in 1981 and his Bachelor of Commerce Degree from the University of McGill in 1975. Mr. Scarlett also holds his ICD.D.

### **Thomas D. Woods (provincial nominee) – Board Chair**

Public Directorships (other than Hydro One and Hydro One Inc.):  
Bank of America Corporation

Public Board Interlocks: None

Mr. Woods is a corporate director. He previously had a 37-year career with CIBC and Wood Gundy, the predecessor firm of CIBC World Markets. He started in Investment Banking, advising companies raising financing in the equity and debt capital markets as well as mergers and acquisitions, and later was Head of Canadian Corporate Banking, Chief Financial Officer, Chief Risk Officer and served as Vice Chairman until his retirement in 2014.

Mr. Woods has served on the boards of Bank of America Corporation since 2016, Alberta Investment Management Corporation. Mr. Woods has also acted as Board Chair of Providence St. Joseph's St. Michael's Health Care since 2017 and CIBC Children's Foundation. Previous directorships include TMX Group Inc., DBRS Limited, Jarislowsky Fraser Limited and Covenant House (Board Chair). Mr. Woods has a Bachelor of Applied Science in Industrial Engineering from University of Toronto, and an MBA from Harvard Business School.

### **Cherie L. Brant (provincial nominee)**

Public Directorships (other than Hydro One and Hydro One Inc.): None

Public Board Interlocks: None

Ms. Brant has been a Partner at Dickinson Wright's Toronto law office since 2013 where she has an Indigenous law practice with a focus on commercial real estate, energy and transmission and First Nations economic development. Ms. Brant provides strategic counsel to several First Nations and industry clients seeking to develop projects with First Nations and to understand and address Indigenous rights and interests. As lead counsel, Ms. Brant was instrumental in forming one of the largest First Nations-led limited partnerships in Canada resulting in the Ontario First Nations Sovereign Wealth LP's share purchase of approximately 2.4% of Hydro One Limited.

Ms. Brant is both Mohawk and Ojibway from the Mohawks of the Bay of Quinte and Wikwemikong Unceded Indian Territory. She also serves on the board of the Anishnawbe Health Foundation and is a member of the Canadian Council for Aboriginal Business, Research Advisory Board and the Aboriginal Energy Working Group of the Independent Electricity System Operator. Previous directorships include Women's College Hospital and Trillium Gift of Life.

Ms. Brant has a Bachelor of Environmental Studies, Urban and Regional Planning Program from the University of Waterloo and a Juris Doctor from the University of Toronto. She is a member of the Ontario Bar Association and the Law Society of Ontario.

### **Blair Cowper-Smith (provincial nominee)**

Public Directorships (other than Hydro One and Hydro One Inc.): None

Public Board Interlocks: None

Mr. Cowper-Smith is the principal and founder of Erin Park Business Solutions, a Canadian advisory and consulting firm. Previously, he was Chief Corporate Affairs Officer of Ontario Municipal Employees Retirement System (OMERS) and served as a member of the Senior Executive Team from 2008 to 2017 where his responsibilities included regulatory affairs, law and governance. Prior to joining OMERS he was a Senior Partner at McCarthy Tetrault LLP where his practice focused on mergers and acquisitions, infrastructure, governance and private equity.

Mr. Cowper-Smith's Board experience includes numerous advisory assignments, including governance advisory assignments, with boards of directors including OMERS, Stelco, Hammerson, and includes existing or prior director appointments and board committee leadership roles with companies like Porter Airlines, 407 ETR, the Financial Services Regulatory Authority and Face the Future Foundation. He served until recently on the Public Policy Committee of the Canadian Coalition for Good Governance and on the Securities Advisory Committee of the Ontario Securities Commission. He co-founded The Canadian Council for Public and Private Partnerships which led to a long-term interest in infrastructure policy and delivery of infrastructure based services to Canadians.

## Amended Management's Discussion and Analysis

Mr. Cowper-Smith has a Bachelor of Laws (LLB) and Master of Laws (LLM) from Osgoode Hall Law School at York University and holds his ICD.D. He is a member of the Law Society of Ontario.

### **Anne Giardini, O.C., O.B.C., Q.C.**

Public Directorships (other than Hydro One and Hydro One Inc.):  
Nevsun Resources Ltd.

Public Board Interlocks: None

Ms. Giardini has been a corporate director since 2014 and Chancellor of Simon Fraser University. She previously had a 20-year career with Weyerhaeuser Company Limited, including as Canadian President until her retirement in 2014. Before her tenure as President, she was Vice President and General Counsel at Weyerhaeuser where she worked on corporate, legal, policy and strategic matters. Ms. Giardini has been a newspaper columnist and is the author of two novels.

Ms. Giardini also serves on the boards of Nevsun Resources Ltd., Canada Mortgage & Housing Corporation, World Wildlife Fund (Canada), BC Achievement Foundation, TransLink and the Greater Vancouver Board of Trade. Previous directorships include Thompson Creek Metals Company, Inc. and Weyerhaeuser Company Limited.

Ms. Giardini has a BA in Economics from Simon Fraser University, a Bachelor of Laws from the University of British Columbia and a Master of Law from the University of Cambridge (Trinity Hall). She is licensed to practice law in British Columbia where she is a member of the Law Society of British Columbia (and formerly in Ontario and Washington State). In 2016, Ms. Giardini was appointed an Officer of the Order of Canada and in 2018 she was appointed to the Order of British Columbia.

### **David Hay**

Public Directorships (other than Hydro One and Hydro One Inc.):  
EPCOR Utilities Inc.

Public Board Interlocks: None

Mr. Hay is a corporate director and Managing Director of Delgatie Incorporated (2015). He is the former Vice-Chair and Managing Director of CIBC World Markets Inc. with power, utilities and infrastructure as his major focus (2010 to 2015). From 2004 until 2010, he was President and Chief Executive Officer of New Brunswick Power Corporation and held senior investment banking roles, including Senior Vice-President and Director responsible for mergers and acquisitions with Merrill Lynch Canada and Managing Director of European mergers and acquisitions with Merrill Lynch International. Mr. Hay spent the early part of his career as a practicing lawyer and taught part-time at both the University of Toronto and University of New Brunswick.

Mr. Hay also serves on the boards of EPCOR, SHAD (Chair), the Council of Clean and Reliable Energy and as Chair of the Acquisition Committee of the Beaverbrook Art Gallery. Prior directorships include Toronto Hydro-Electric System Limited where he was Vice-Chair.

Mr. Hay has a Bachelor of Laws from Osgoode Hall Law School, York University and a Bachelor of Arts from the University of Toronto (Victoria College) and holds his ICD.D.

### **Timothy E. Hodgson**

Public Directorships (other than Hydro One and Hydro One Inc.):  
Alignvest Acquisition II Corporation and MEG Energy Corp.

Public Board Interlocks: None

Mr. Hodgson has been a Managing Partner of Alignvest Management Corporation since 2012. Mr. Hodgson is also the Chief Compliance Officer of Alignvest Capital Management Inc. and Alignvest Investment Management Corporation. Mr. Hodgson was Special Advisor to Mr. Mark Carney, Governor of the Bank of Canada from 2010 to 2012, where he lead the Bank's market infrastructure initiatives to build a new repo clearinghouse business for Canada; reform Canada's over-the-counter derivatives markets; and review changes to systemically important market infrastructure businesses in Canada.

From 1990 to 2010, Mr. Hodgson held various positions in New York, London, Silicon Valley and Toronto with Goldman Sachs and served as Chief Executive Officer of Goldman Sachs Canada from 2005 to 2010 with overall responsibilities for the firm's operations, client relationships and regulatory matters in the region.

Mr. Hodgson currently sits on the boards of The Public Sector Pension Investment Board (PSP Investments), MEG Energy, Alignvest Acquisition II Corporation, and Next Canada. Mr. Hodgson's prior directorships include The Global Risk Institute, KGS-Alpha Capital Markets, and the Richard Ivey School of Business. Mr. Hodgson also served on the board of Bridgepoint Health for eight years until July 2014.

Mr. Hodgson holds a Masters of Business Administration from The Richard Ivey School of Business at Western University and a Bachelor of Commerce from the University of Manitoba. He is a Chartered Professional Accountant (CPA), Chartered Accountant (CA) and holds his ICD.D.

### **Jessica L. McDonald**

Public Directorships (other than Hydro One and Hydro One Inc.):  
Coeur Mining Inc. and Trevali Mining Corporation

Public Board Interlocks: None

Ms. McDonald has been Chair of the Board of Directors and Interim President and Chief Executive Officer of Canada Post Corporation since 2017. From 2014 to 2017, she served as President and Chief Executive Officer of British Columbia Hydro & Power Authority. Ms. McDonald was also Executive Vice President of HB Global Advisors Corp., as well as a successful practice in mediation and negotiation on major commercial and industrial projects. In addition, Ms. McDonald has held many positions with the BC government, including the most senior public service position in the provincial government as Deputy Minister to the Premier, Cabinet Secretary and Head of the BC Public Service from 2005 to 2009, responsible for overseeing all aspects of government operations.

Ms. McDonald also serves on the boards of Coeur Mining Inc. and Trevali Mining Corporation, and is on the Member Council of Sustainable Development Technology Canada. Previous directorships include Powertech Labs (Chair) and Powerex Corp.

Ms. McDonald has a Bachelor of Arts (Political Science) from the University of British Columbia. She is also a member of the Institute of Corporate Directors and holds her ICD.D.

## Amended Management's Discussion and Analysis

### Russel C. Robertson (provincial nominee)

Public Directorships (other than Hydro One and Hydro One Inc.):  
Bausch Health Companies Inc. and Turquoise Hill Resources Ltd.

Public Board Interlocks: None

Mr. Robertson is a corporate director and served as Executive Vice President and Head, Anti-Money Laundering, BMO Financial Group from 2008 to 2016. Mr. Robertson has served as Chief Financial Officer, BMO Financial Group and Executive Vice President, Business Integration where he oversaw the integration of Harris Bank and M&I Bank forming BMO Harris Bank. Before joining BMO, he spent over 35 years as a Chartered Professional Accountant holding various senior positions including the positions of Vice-Chair, Deloitte & Touche LLP (Canada) and Canadian Managing Partner, Arthur Andersen LLP (Canada).

Mr. Robertson has also served on the board of Bausch Health Companies Inc. since 2016 and acts as the chairperson of the Audit and Risk Committee and has served on the Board of Turquoise Hill Resources since 2012. Previous directorships include Virtus Investment Partners, Inc.

Mr. Robertson has a Bachelor of Arts (Honours) in Business Administration from the Ivey School of Business at the University of Western Ontario. He is a Chartered Professional Accountant (FCPA, FCA) and a Fellow of the Institute of Chartered Accountants (Ontario). He is also a member of the Institute of Corporate Directors and holds his ICD.D.

### William H. Sheffield

Public Directorships (other than Hydro One and Hydro One Inc.):  
Houston Wire & Cable Company, Velan Inc.

Public Board Interlocks: None

Mr. Sheffield is a corporate director. He is the former Chief Executive Officer of Sappi Fine Papers, headquartered in South Africa. Previously, he held senior roles with Abitibi-Consolidated, Inc. and Abitibi-Price, Inc. He began his career in the steel industry and held General Manager, Industrial Engineering and Cold Mill Operating roles at Stelco Inc.

Mr. Sheffield has served on the board of Houston Wire & Cable Company since 2006 where he acts as Chairman. Mr. Sheffield also serves on the boards of Velan, Inc., Burnbrae Farms Ltd., Longview Aviation Capital, Family Enterprise Xchange, and 4iiii Innovations Inc. Previous directorships include Canada Post Corporation, Ontario Power Generation, Corby Distilleries, Royal Group Technologies and SHAD.

Mr. Sheffield has a Bachelor of Science (Chemistry) from Carleton University and an MBA from McMaster University. Mr. Sheffield also holds his ICD.D and in 2015, he was awarded a Fellowship from the National Association of Corporate Directors in the US. He also completed the Family Enterprise Advisors Program (FEA) at the University of British Columbia.

### Melissa Sonberg

Public Directorships (other than Hydro One and Hydro One Inc.):  
Exchange Income Corporation

Public Board Interlocks: None

Ms. Sonberg is a corporate director and has been Adjunct Professor and Executive-in-Residence at McGill University's Desautel Faculty of Management since 2014. She spent the early part of her career in the healthcare industry before joining Air Canada, where she held leadership positions in a range of customer facing, operational and corporate functions. Ms. Sonberg was part of the founding executive team of Aeroplan, now part of AIMIA. Ms. Sonberg held positions of Senior Vice President, Human Resources & Corporate Affairs and Senior Vice President, Global Brands, Communications and External Affairs at AIMIA from 2001 to 2013.

Ms. Sonberg also serves on the boards of Exchange Income Corporation, MD Financial Holdings, Inc., Canadian Professional Sales Association, Group Touchette, Women in Capital Markets and Equitas – International Centre for Human Rights. Previous directorships include Rideau, Inc., Via Rail Canada, University of Ottawa, International Advisory Board and the McGill University Health Centre.

Ms. Sonberg has a Bachelor of Science (Psychology) from McGill University and a Masters of Health Administration from the University of Ottawa. She is a Certified Human Resource Executive and holds her ICD.D.

### Information Regarding Certain Directors and Executive Officers

As at December 31, 2018, the directors and executive officers of Hydro One and its subsidiaries beneficially owned, controlled or directed, directly or indirectly, as a group, 15,905 common shares, which represented approximately 0.003% of the outstanding common shares.

As at December 31, 2018, approximately 36.4% of the executives (those who hold a vice president role and above or equivalent) (12 out of 33) across Hydro One and its major subsidiaries, including 1 of 5 executive officers, are women.

### Corporate Cease Trade Orders and Bankruptcies

Except as described below:

- none of the directors or executive officers of Hydro One or Hydro One Inc. nor any shareholder holding shares sufficient to materially affect control of Hydro One or Hydro One Inc. is, or within the last 10 years has served as, a director or executive officer of any company that, during such service or within a year after the end of such service, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets;
- none of the directors or executive officers of Hydro One or Hydro One Inc. is, or within the last 10 years has served as, a director, CEO, or CFO of any company that, during such service or as a result of an event that occurred during such service, was subject to an order (including a cease trade order, or similar order or an order that denied access to any exemption under securities legislation), for a period of more than 30 consecutive days; or
- none of the directors or executive officers of Hydro One or Hydro One Inc. nor any shareholder holding shares sufficient to materially affect control of Hydro One or Hydro One Inc., within the last 10 years has become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director.

## Amended Management's Discussion and Analysis

Blair Cowper-Smith served as a Director of Golfsmith International Holdings GP Inc. and Golf Town Canada Inc. (Golf Town) from 2016 to 2018. On September 14, 2016, Golf Town filed for and was granted Court bankruptcy protection under the CCAA. Golf Town emerged from Court protection after being sold to Fairfax Financial Holdings Limited and CI Investments Inc. in October 2016.

### Penalties or Sanctions

None of the directors or executive officers of Hydro One or Hydro One Inc., nor any shareholder holding shares sufficient to materially affect control of Hydro One or Hydro One Inc., has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor making an investment decision.

### Conflicts of Interest

To the best of Hydro One's and Hydro One Inc.'s knowledge, there are no existing material potential conflicts of interest among Hydro One or any of its subsidiaries and the directors or executive officers of Hydro One or any of its subsidiaries as a result of their outside business interests as at the date hereof. Certain of the directors and executive officers serve as directors and executive officers of other public companies. Accordingly, conflicts of interest may arise which could influence these persons in evaluating possible acquisitions or in generally acting on behalf of Hydro One or Hydro One Inc. Where conflicts arise, they are managed through a variety of measures, including declaration of the conflict, recusal from meetings and/or portions of meetings, and the creation of separate board materials for the affected directors.

### Interest of Management and Others in Material Transactions

There are no material interests, direct or indirect, of any director or executive officer of Hydro One and its subsidiaries, or any associate or affiliate of any of the foregoing persons, in any transaction within the three years before the date hereof that has materially affected or is reasonably expected to materially affect Hydro One or Hydro One Inc.

The following table summarizes the committee memberships and independence status of Board members:

Director	Committees				Independence	
	Audit Committee	Governance Committee	Human Resources Committee	Health, Safety, Environment and Indigenous Peoples Committee	Independent of Hydro One	Independent of the Province
Cherie Brant		✓		✓	✓	✓
Blair Cowper-Smith		✓	✓		✓	✓
Anne Giardini	✓			✓	✓	✓
David Hay	✓			✓	✓	✓
Timothy Hodgson		✓	✓		✓	✓
Jessica McDonald	✓		✓		✓	✓
Russel Robertson	✓		✓		✓	✓
William Sheffield	✓			✓	✓	✓
Melissa Sonberg		✓	✓		✓	✓
Tom Woods					✓	✓

### Indebtedness of Directors and Executive Officers

No director, executive officer, employee, former director, former executive officer or former employee or associate of any director or executive officer of Hydro One or any of its subsidiaries had any outstanding indebtedness to Hydro One or any of its subsidiaries except routine indebtedness or had any indebtedness that was the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by Hydro One or any of its subsidiaries.

### Independence Matters

The Board of Hydro One and Hydro One Inc. currently consists of 10 directors, all of whom are independent of Hydro One and Hydro One Inc. and independent of the Province within the meaning of the Governance Agreement.

For Hydro One's purposes, an independent director is one who is independent of Hydro One and independent of the Province. Directors will be independent of Hydro One if they are independent within the meaning of all Canadian securities laws governing the disclosure of corporate governance practices and stock exchange requirements imposing a number or percentage of independent directors. Pursuant to Canadian securities laws, a director who is "independent" within the meaning of applicable securities laws is one who is free from any direct or indirect relationship which could, in the view of the board, be reasonably expected to interfere with a director's independent judgement, with certain specified relationships deemed to be non-independent. A director will be "independent of the Province" if he or she is independent of Hydro One under Ontario securities laws governing the disclosure of corporate governance practices, where the Province and certain specified provincial entities are treated as Hydro One's parent under that definition, but excluding current directors where the relationship ended before August 31, 2015. The Governance Agreement requires each of the directors, other than the CEO, to be both independent of Hydro One and independent of the Province. The Chair of Hydro One is independent of Hydro One and the Province.

## Amended Management's Discussion and Analysis

### Diversity Policy

The Board has adopted a board diversity policy which formalizes the company's commitment to diversity and its desire to maintain a board comprising talented and dedicated directors whose skills, experience, knowledge and backgrounds reflect the diverse nature of the business

### Director Attendance

Directors are expected to attend board meetings, meetings of the committees on which they serve and the annual meeting of shareholders.

### Number of Board and Committee Meetings (August 13, 2018 to December 31, 2018)<sup>1</sup>:

	Regular	Non-Regular	In Camera Sessions
Board	2	11	13
Audit Committee	1	4	5
Health, Safety, Environment and Indigenous Peoples Committee	1	–	1
Human Resources Committee	2	3	5
Governance Committee	1	3	4

<sup>1</sup> All of the current directors were appointed directors of Hydro One effective August 13, 2018. The directors of Hydro One are also directors of Hydro One Inc. and the two boards and each committee thereof hold joint meetings.

### Audit Committee

The Audit Committee must consist of at least three directors, all of whom are persons determined by Hydro One to be both "independent" (within the meaning of all Canadian securities laws and stock exchange requirements and the Governance Agreement) and "financially literate" (within the meaning of other applicable requirements or guidelines for audit committee service under securities laws or the rules of any applicable stock exchange, including National Instrument 52-110 – *Audit Committees*). At least one member of the Audit Committee will qualify as an "audit committee financial expert" as defined by the applicable rules of the US Securities and Exchange Commission. The Audit Committee comprises William Sheffield (Chair), Anne Giardini, David Hay, Jessica McDonald and Russel Robertson. Each of the Audit Committee members is independent and financially literate and each has an understanding of the accounting principles used to prepare Hydro One's financial statements and varied experience as to the general application of such accounting principles, as well as an understanding of the internal controls and procedures necessary for financial reporting. Russel Robertson and David Hay each qualify as an audit committee financial expert.

Please refer to the biographies of our Audit Committee members described under "– Directors and Executive Officers" above for details of their additional invaluable skills and experience.

### Human Resource Committee

Hydro One's management team, the Human Resources Committee and the Company's compensation advisors all play a key role in determining executive compensation for the company's directors and executives and in managing compensation risk on behalf of the Board of Hydro One. The Human Resources Committee is responsible for assisting the Board in fulfilling its oversight responsibilities relating to the attraction and retention of key senior management.

All of the members of the Human Resources Committee are independent. The Human Resources Committee comprises Melissa Sonberg (Chair), Blair Cowper-Smith, Timothy Hodgson, Jessica McDonald and Russel Robertson. All of the members of the Human Resources Committee have gained the

environment in which it operates, including an appropriate number of female directors. The Board aspires towards a board composition in which each gender comprises at least 40% of the directors on the Board. Currently, the Board includes four female directors (40%).

following relevant experience in human resources and compensation by serving as an executive officer (or equivalent) of a major organization and/or through prior service on the compensation committee of a stock exchange listed company or otherwise:

- human resources experience (experience with benefit, pension and compensation programs (in particular, executive compensation));
- risk management experience (knowledge and experience with internal risk controls, risk assessments and reporting as it pertains to executive compensation); and
- executive leadership experience (experience as a senior executive/officer of a public company or major organization).

Please refer to the biographies of our Human Resources Committee members described under "– Directors and Executive Officers" above for details of their additional invaluable skills and experience.

### CEO Selection Committee

The Board has also formed an ad hoc CEO Selection Committee to identify and select a President and CEO.

### Compensation Policies and Practices

Other than as set forth in Hydro One's management information circular dated March 19, 2018 prepared in connection with the annual meeting of shareholders held on May 15, 2018 or as otherwise described below, there have been no material changes to the policies and practices adopted by the Board of Hydro One or Hydro One Inc. to determine compensation for Hydro One's or Hydro One Inc.'s directors and executive officers since January 1, 2018.

### Changes to Hydro One's Board and CEO Compensation

As disclosed under "– Directors and Executive Officers" above, on July 11, 2018, Hydro One, on behalf of itself and Hydro One Inc., announced that it had entered into the Letter Agreement for the purpose of the orderly replacement of the Board of Hydro One and Hydro One Inc. and the retirement of Mayo Schmidt as the CEO effective July 11, 2018. In

## Amended Management's Discussion and Analysis

accordance with the Letter Agreement, Hydro One has agreed to consult with the Province in respect of future matters of executive compensation. In addition, the then-existing Hydro One and Hydro One Inc. Board volunteered and agreed to immediately reduce board compensation to the levels contemplated by the pre-January 1, 2018 director compensation policy. The then-existing Hydro One and Hydro One Inc. Board also volunteered and agreed to forego any compensation for their service after June 30, 2018.

In connection with Mr. Schmidt's retirement, he received amounts consistent with Hydro One's retirement policies applicable to his outstanding equity awards and his employment agreement as previously disclosed and was not entitled to severance. Mr. Schmidt received a \$0.4 million lump sum payment in lieu of all post-retirement benefits and allowances.

### Urgent Priorities Act (formerly, Bill 2)

In July 2018, the Province introduced the *Urgent Priorities Act, 2018* (Urgent Priorities Act), which amended the *Ontario Energy Board Act, 1998* (OEB Act) and introduced the *Hydro One Accountability Act* (Accountability Act). The Accountability Act came into force in August 2018. The Accountability Act requires the Board to establish a new compensation framework for the Board, the CEO and other executives, in consultation with the Province and the other five largest shareholders of Hydro One Limited (which framework must include policies governing severance and other entitlements in connection with any termination of employment). The new compensation framework is not effective until approved by Management Board of Cabinet of the Province. In addition, the Management Board of Cabinet of the Province has the authority to issue directives governing the compensation of directors and certain executives of Hydro One and its subsidiaries (excluding subsidiaries incorporated outside Canada). In February 2019, the Board published a revised compensation framework that complies with the requirements of the Urgent Priorities Act. The Accountability Act also requires Hydro One to annually provide public disclosure concerning compensation paid to certain executives. The Accountability Act may adversely impact Hydro One and Hydro One Inc.'s ability to continue to attract and retain executives.

The OEB Act was amended to preclude the OEB from approving or fixing rates for Hydro One or any of its subsidiaries that include any amount in respect of compensation paid to the CEO and other executives. The impact of this amendment is expected to restrict Hydro One's ability to recover certain amounts paid for executive compensation through separate rate mechanisms, which is expected to result in a reduction to Hydro One's net income for the year ending December 31, 2019 of up to \$14 million and is subject to a final determination by the OEB. The reduction may be materially lower, depending on the determination by the OEB of the executives whose compensation is to be excluded. The Urgent Priorities Act expressly provides that certain causes of action and proceedings are not available or will be barred against the Province, Hydro One or any of its subsidiaries, or any of its current or former officers, directors, employees or agents in respect of the Accountability Act, the Province's involvement in compensation matters or other aspects of the corporate governance of Hydro One or any of its subsidiaries or any alleged misrepresentation in any prospectus, document or other public statement related to the involvement of the Province in compensation matters at Hydro One or any of its subsidiaries.

### Province of Ontario

Notwithstanding the Governance Agreement, and in light of actions taken by the Province following the provincial election in June 2018 including the passage of the Urgent Priorities Act, the Province may elect to make further decisions relevant to Hydro One that could be detrimental to the interests of various stakeholders of Hydro One.

### HYDRO ONE WORK FORCE

Hydro One has a skilled and flexible work force of approximately 5,700 regular employees and 2,200 non-regular employees province-wide, comprising of a mix of skilled trades, engineering, professional, managerial and executive personnel. Hydro One's regular employees are supplemented primarily by accessing a large external labour force available through arrangements with the Company's trade unions for variable workers, sometimes referred to as "hiring halls", and also by access to contract personnel. The hiring halls offer Hydro One the ability to flexibly utilize highly trained and appropriately skilled workers on a project-by-project and seasonal basis.

The following table sets out the number of Hydro One employees as at December 31, 2018:

	Regular Employees	Non-Regular Employees	Total
Power Workers' Union (PWU) <sup>1</sup>	3,583	856	4,439
Society of United Professionals (Society)	1,458	36	1,494
Canadian Union of Skilled Workers (CUSW) and construction building trade unions <sup>2</sup>	—	1,277	1,277
Total employees represented by unions	5,041	2,169	7,210
Management and non-represented employees	667	22	689
Total employees <sup>3</sup>	5,708	2,191	7,899

1 Includes 715 non-regular "hiring hall" employees covered by the PWU agreement.

2 The construction building trade unions have collective agreements with the Electrical Power Systems Construction Association (EPSCA).

3 The average number of Hydro One employees in 2018 was approximately 8,600, consisting of approximately 5,650 regular employees and approximately 2,950 non-regular employees.

### Collective Agreements

On March 1, 2018, Hydro One insourced its customer service operations (CSO), which had been previously outsourced to Inergi LP and Vertex Customer Management (Canada) Limited since 2002. The insourcing was facilitated through labour agreements reached with the PWU and the Society (formerly the Society of Energy Professionals) in 2017.

The prior collective agreement with the PWU expired on March 31, 2018.

On March 26, 2018, Hydro One and the PWU reached a tentative agreement, and on June 27, 2018, the agreement was ratified by the PWU. The term of the agreement is for two years ending on March 31, 2020.

## Amended Management's Discussion and Analysis

### Stock-based Compensation

During 2018 and 2017, the Company granted awards under its LTIP, consisting of Performance Share Units (PSUs), Restricted Share Units (RSUs), and Stock Options, all of which are equity settled. At December 31, 2018 and 2017, the following LTIP awards were outstanding:

December 31 (number of units)	2018	2017
PSUs	605,180	429,980
RSUs	442,470	393,430
Stock Options	949,910	—

### NON-GAAP MEASURES

#### FFO

FFO is defined as net cash from operating activities, adjusted for (i) changes in non-cash balances related to operations, (ii) dividends paid on preferred shares, and (iii) distributions to noncontrolling interest. Management believes that FFO is helpful as a supplemental measure of the Company's operating cash flows as it excludes timing-related fluctuations in non-cash operating working capital and cash flows not attributable to common shareholders. As such, FFO provides a consistent measure of the cash generating performance of the Company's assets.

Year ended December 31 (millions of dollars)	2018	2017
Net cash from operating activities	1,575	1,716
Changes in non-cash balances related to operations	23	(113)
Preferred share dividends	(18)	(18)
Distributions to noncontrolling interest	(8)	(6)
<b>FFO</b>	<b>1,572</b>	<b>1,579</b>

#### Adjusted Net Income and Adjusted EPS

The following basic and diluted Adjusted EPS has been calculated by management on a supplementary basis which excludes costs and income related to the Avista Corporation acquisition, as well as the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses, from net income attributable to common shareholders. Adjusted EPS is used internally by management to assess the Company's performance and is considered useful because it excludes the impact of acquisition-related costs and loss or gain on the foreign exchange contract, as well as the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses. It provides 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)	2018	2017
Net income (loss) attributable to common shareholders	(89)	658
Impacts related to Avista Corporation acquisition:		
OM&A – Avista Corporation-related costs (before tax)	11	20
Financing charges – Avista Corporation-related costs (before tax)	58	22
Financing charges – loss (gain) on foreign exchange contract (before tax)	(25)	3
Tax impact	(15)	(9)
Avista Corporation-related impacts (after tax)	29	36
Impacts related to OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses:		
Reversal of revenues	68	—
Deferred tax expense	799	—
OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses impacts (after tax)	867	—
Adjusted net income attributable to common shareholders	807	694
Weighted average number of shares		
Basic	595,756,470	595,287,586
Effect of dilutive stock-based compensation plans	2,147,473	2,234,665
Diluted	597,903,943	597,522,251
Adjusted EPS		
Basic	\$ 1.35	\$ 1.17
Diluted	\$ 1.35	\$ 1.16

## Amended Management's Discussion and Analysis

### 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)	2018	2017
Revenues	6,150	5,990
Less: Purchased power	2,899	2,875
<b>Revenues, net of purchased power</b>	<b>3,251</b>	<b>3,115</b>

Year ended December 31 (millions of dollars)	2018	2017
Distribution revenues	4,422	4,366
Less: Purchased power	2,899	2,875
<b>Distribution revenues, net of purchased power</b>	<b>1,523</b>	<b>1,491</b>

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.

### RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2018. 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 Province. The following is a summary of the Company's related party transactions during the years ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)		2018	2017
Related Party	Transaction		
<b>Province</b>	Dividends paid	<b>275</b>	<b>301</b>
IESO	Power purchased	1,636	1,583
	Revenues for transmission services	1,615	1,521
	Amounts related to electricity rebates	477	357
	Distribution revenues related to rural rate protection	239	247
	Distribution revenues related to the supply of electricity to remote northern communities	35	32
	Funding received related to CDM programs	62	59
OPG	Power purchased	10	9
	Revenues related to provision of services and supply of electricity	9	8
	Costs related to the purchase of services	—	1
OEFC	Power purchased from power contracts administered by the OEFC	2	2
OEB	OEB fees	8	8

### RISK MANAGEMENT AND RISK FACTORS

#### Risks Relating to Hydro One's Business

##### Regulatory Risks and Risks Relating to Hydro One's Revenues

###### *Risks Relating to Obtaining Rate Orders*

The Company is subject to the risk that the OEB will not approve the Company's transmission and distribution revenue requirements requested in outstanding or future applications for rates. Rate applications for revenue requirements are subject to the OEB's review process, usually involving participation from intervenors and a public hearing process. There can be no assurance that resulting decisions or rate orders issued by the OEB will

permit Hydro One to recover all costs actually incurred, costs of debt and income taxes, or to earn a particular ROE. A failure to obtain acceptable rate orders, or approvals of appropriate returns on equity and costs actually incurred, may materially adversely affect: Hydro One's transmission or distribution businesses, the undertaking or timing of capital expenditures, ratings assigned by credit rating agencies, the cost and issuance of long-term debt, and other matters, any of which may in turn have a material adverse effect on the Company. In addition, there is no assurance that the Company will receive regulatory decisions in a timely manner and, therefore, costs may be incurred prior to having an approved revenue requirement and cash flows could be impacted.

### *Risks Relating to Actual Performance Against Forecasts*

The Company's ability to recover the actual costs of providing service and earn the allowed ROE depends on the Company achieving its forecasts established and approved in the rate-setting process. Actual costs could exceed the approved forecasts if, for example, the Company incurs operations, maintenance, administration, capital and financing costs above those included in the Company's approved revenue requirement. The inability to obtain acceptable rate decisions or to recover any significant difference between forecast and actual expenses could materially adversely affect the Company's financial condition and results of operations.

Further, the OEB approves the Company's transmission and distribution rates based on projected electricity load and consumption levels, among other factors. If actual load or consumption materially falls below projected levels, the Company's revenue and net income for either, or both, of these businesses could be materially adversely affected. Also, the Company's current revenue requirements for these businesses are based on cost and other assumptions that may not materialize. There is no assurance that the OEB would allow rate increases sufficient to offset unfavourable financial impacts from unanticipated changes in electricity demand or in the Company's costs.

The Company is subject to risk of revenue loss from other factors, such as economic trends and weather conditions that influence the demand for electricity. The Company's overall operating results may fluctuate substantially on a seasonal and year-to-year basis based on these trends and weather conditions. For instance, a cooler than normal summer or warmer than normal winter can be expected to reduce demand for electricity below that forecast by the Company, causing a decrease in the Company's revenues from the same period of the previous year. The Company's load could also be negatively affected by successful CDM programs whose results exceed forecasted expectations.

### *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 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 decision (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 a portion of the tax savings should be accrued to the ratepayers. In October 2017, the Company filed a motion to review and vary (Motion) the Original Decision and filed an appeal with the Divisional Court of Ontario (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 the 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, which represents the amount of \$885 million as previously disclosed, reduced by \$18 million related to forgone revenue and net tax recovery adjustments. The Company is currently considering its options with respect to the Appeal.

### *Risks Relating to Other Applications to the OEB*

The Company is also subject to the risk that it will not obtain, or will not obtain in a timely manner, required regulatory approvals for other matters, such as leave to construct applications, applications for mergers, acquisitions, amalgamations and divestitures, and environmental approvals. Decisions to acquire or divest other regulated businesses licensed by the OEB are subject to OEB approval. Accordingly, there is the risk that such matters may not be approved or that unfavourable conditions will be imposed by the OEB.

### *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 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.

The OEB's recent 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.

## Amended Management's Discussion and Analysis

To the extent that the OEB approves an In-Service Variance Account for the transmission and/or distribution businesses, and should the Company fail to meet the threshold levels of in-service capital, the OEB may reclaim a corresponding portion of the Company's revenues.

### *Risks Relating to Capital Expenditures*

In order to be recoverable, capital expenditures require the approval of the OEB, either through the approval of capital expenditure plans, rate base or revenue requirements for the purposes of setting transmission and distribution rates, which include the impact of capital expenditures on rate base or cost of service. There can be no assurance that all capital expenditures incurred by Hydro One will be approved by the OEB. Capital cost overruns may not be recoverable in transmission or distribution rates. The Company could incur unexpected capital expenditures in maintaining or improving its assets, particularly given that new technology may be required to support renewable generation and unforeseen technical issues may be identified through implementation of projects. There is risk that the OEB may not allow full recovery of such expenditures in the future. To the extent possible, Hydro One aims to mitigate this risk by ensuring prudent expenditures, seeking from the regulator clear policy direction on cost responsibility, and pre-approval of the need for capital expenditures.

Any regulatory decision by the OEB to disallow or limit the recovery of any capital expenditures would lead to a lower than expected approved revenue requirement or rate base, potential asset impairment or charges to the Company's results of operations, any of which could have a material adverse effect on the Company.

### *Risk of Recoverability of Total Compensation Costs*

The Company manages all of its total compensation costs, including pension and other post-employment and post-retirement benefits, subject to restrictions and requirements imposed by the collective bargaining process. Any element of total compensation costs which is disallowed in whole or part by the OEB and not recoverable from customers in rates could result in costs which could be material and could decrease net income, which could have a material adverse effect on the Company.

The changes flowing from the Urgent Priorities Act are expected to restrict Hydro One's ability to recover certain amounts paid for executive compensation through separate rate mechanisms, which is estimated to result in a reduction in Hydro One's net income for the year ending December 31, 2019 of up to \$14 million, and is subject to a final determination by the OEB. The reduction may be materially lower, depending on the determination by the OEB of the executives whose compensation is to be excluded.

### **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 regulation 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 (for example, potential government actions relating to the Province's election promise to reduce hydro rates by 12%). 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 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.

In June 2018, Moody's downgraded the long-term debt rating for Hydro One Inc. and in September 2018, S&P lowered its issuer credit ratings on the Company and Hydro One Inc. (as detailed above in the "Credit Ratings" section). These ratings downgrades reflect the ratings 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.

### **Executive Recruitment and Retention Risk**

Involvement by the Province relating to executive compensation, and Hydro One executive compensation constraints flowing from the Urgent Priorities Act 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.

### Management Retention

In the fourth quarter of 2018, the Company entered into retention agreements with certain of its key officers, namely Messrs. Dobson, Kiraly, Meneley, Scarlett, Lopez and Ms. McKellar, in order to ensure stability in the organization and to allow the Company sufficient time to complete its recruitment of a new CEO and support the transition to a renewed senior management team. The retention arrangements are intended to ensure the continued employment of those officers for periods ranging from February 28, 2019 through May 31, 2019 depending on the officer. The retention agreements generally confirm, among other things, that so long as the individual does not resign prior to a specified date (being the retention date), certain key terms (other than severance) of the individual's employment arrangements will be respected, including the vesting of his or her outstanding share-based awards and a pro-rata portion of his or her short-term and long-term incentive in respect of the 2019 fiscal year. To date, Mr. Meneley has notified the Company that he intends to resign effective March 1, 2019, and Ms. McKellar has notified the Company that she intends to retire effective April 1, 2019. The retention agreements may be extended by mutual agreement, however, there is no assurance that any of the key officers will remain after their retention dates, in which case the Company could have a lack of senior management to run the Company's business. While the Company has succession plans in place for certain key officers, there is no assurance that there will not be an impact on the Company's business if any or all such key officers resign before, on, or after, their respective retention dates. In addition, there is no assurance that the Company will be able to attract and retain qualified replacement officers on a timely basis, or at all, in order to replace these individuals. The failure to attract and retain qualified officers could have a material adverse effect on the Company.

### 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, Metis or Inuit group) and are increasingly willing to assert their claims through the courts, tribunals, or by direct action. These claims and/or settlement of these claims could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations, including the development of current and future projects.

The Company's operations and activities may give rise to the Crown's duty to consult and potentially accommodate Indigenous communities. Procedural aspects of the duty to consult may be delegated to the Company by the Province or the federal government. A perceived failure by the Crown to sufficiently consult an Indigenous community, 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, the OEFC holds legal title to these assets and it is expected that the Company will manage them until it has obtained permits to complete the title transfer. To occupy Reserves, the Company must have valid permits. For each permit, the Company must negotiate an agreement (in the form of a memorandum of understanding) with the First Nation, the OEFC and any members of the First Nation who have occupancy rights. The agreement includes provisions whereby the First Nation consents to the issuance of a permit. For transmission assets, the Company must negotiate terms of payment. It is difficult to predict the aggregate amount that the Company may have to pay to obtain the required agreements from First Nations. If the Company cannot reach satisfactory agreements with the relevant First Nation to obtain federal permits, it may have to relocate these assets to other locations and restore the lands at a cost that could be substantial. In a limited number of cases, it may be necessary to abandon a line and replace it with diesel generation facilities. In either case, the costs relating to these assets could have a material adverse effect on the Company if the costs are not recoverable in future rate orders.

### Compliance with Laws and Regulations

Hydro One must comply with numerous laws and regulations affecting its business, including requirements relating to transmission and distribution companies, environmental laws, employment laws and health and safety laws. The failure of the Company to comply with these laws could have a material adverse effect on the Company's business. See also " – Health, Safety and Environmental Risk".

For example, Hydro One's licensed transmission and distribution businesses are required to comply with the terms of their licences, with codes and rules issued by the OEB, and with other regulatory requirements, including regulations of the National Energy Board. In Ontario, the Market Rules issued by the IESO require the Company to, among other things, comply with the reliability standards established by the NERC and Northeast Power Coordinating Council, Inc. (NPCC). The incremental costs associated with compliance with these reliability standards are expected to be recovered through rates, but there can be no assurance that the OEB will approve the recovery of all of such incremental costs. Failure to obtain such approvals could have a material adverse effect on the Company.

## Amended Management's Discussion and Analysis

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. For example, the federal government's November 2018 Fall Economic Statement announced measures related to accelerated investment incentives which, if implemented, could have a material adverse impact on Hydro One.

### Risk of Natural and Other Unexpected Occurrences

The Company's facilities are exposed to the effects of severe weather conditions, natural disasters, man-made events including but not limited to cyber and physical terrorist type attacks, events which originate from third-party connected systems, or any other potentially catastrophic events. 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. 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.

### Risk Associated with Information Technology Infrastructure and Data Security

The Company's ability to operate effectively in the Ontario electricity market is, in part, dependent upon it developing, maintaining and managing complex IT systems which are employed to operate and monitor its transmission and distribution facilities, financial and billing systems and other business systems. The Company's increasing reliance on information systems and expanding data networks increases its exposure to information security threats. The Company's transmission business is required to comply with various rules and standards for transmission reliability, including mandatory standards established by the NERC and the NPCC. These include standards relating to cyber-security and IT, 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 IT 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 and IT systems could result in service disruptions and system failures, which could have a material

adverse effect on the Company, including as a result of a failure to provide electricity to customers. Due to operating critical infrastructure, Hydro One may be at greater risk of cyber-attacks from third parties (including state run or controlled parties) that could impair or incapacitate its assets. In addition, in the course of its operations, the Company collects, uses, processes and stores information which could be exposed in the event of a cyber-security incident or other unauthorized access or disclosure, such as information about customers, suppliers, counterparties, employees and other third parties.

Security and system disaster recovery controls are in place; however, there can be no assurance that there will not be system failures or security breaches or that such threats would be detected or mitigated on a timely basis. Upon occurrence and detection, the focus would shift from prevention to isolation, remediation and recovery until the incident has been fully addressed. Any such system failures or security breaches could have a material adverse effect on the Company.

### Labour Relations Risk

The substantial majority of the Company's employees are represented by either the PWU or the Society. Over the past several years, significant effort has been expended to increase Hydro One's flexibility to conduct operations in a more cost-efficient manner. Although the Company has achieved improved flexibility in its collective agreements, the Company may not be able to achieve further improvements. The Company reached an agreement with the PWU for a renewal collective agreement with a two-year term, covering the period from April 1, 2018 to March 31, 2020. The Company also reached a renewal collective agreement with the CUSW for a five-year term, covering the period from May 1, 2017 to April 30, 2022. Additionally, the EPSCA and a number of construction unions have reached renewal agreements, to which Hydro One is bound, for a five-year term, covering the period from May 1, 2015 to April 30, 2020. Agreements were also reached with the Society and the PWU to facilitate the insourcing of CSO services effective March 1, 2018. Future negotiations with unions present the risk of a labour disruption and the ability to sustain the continued supply of energy to customers. The Company also faces financial risks related to its ability to negotiate collective agreements consistent with its rate orders. In addition, in the event of a labour dispute, the Company could face operational risk related to continued compliance with its requirements of providing service to customers. Any of these could have a material adverse effect on the Company. Collective agreements requiring renewal in 2019 include the Society agreement and the PWU CSO agreement, expiring on March 31, 2019 and September 30, 2019, respectively.

### Work Force Demographic Risk

By the end of 2018, approximately 16% 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 2019, approximately 18% could be eligible. These percentages are not evenly spread across the Company's work force, but tend to be most significant in the most senior levels of the Company's staff and especially among management staff. During 2018, approximately 4% of the Company's work force (down from 5% in 2017) elected to retire. Accordingly, the Company's

## Amended Management's Discussion and Analysis

continued success will be tied to its ability to continue to attract and retain sufficient qualified staff to replace the capability lost through retirements and meet the demands of the Company's work programs.

In addition, the Company expects the skilled labour market for its industry will remain highly competitive. Many of the Company's current and potential employees being sought after possess skills and experience that are also highly coveted by other organizations inside and outside the electricity sector. The failure to attract and retain qualified personnel for Hydro One's business could have a material adverse effect on the Company.

### Risk Associated with Arranging Debt Financing

The Company expects to borrow to repay its existing indebtedness and to fund a portion of capital expenditures. Hydro One Inc. has substantial debt principal repayments, including \$731 million in 2019, \$653 million in 2020, and \$803 million in 2021. In addition, from time to time, the Company may draw on its syndicated bank lines and/or issue short-term debt under Hydro One Inc.'s \$1.5 billion commercial paper program which would mature within one year of issuance. The Company also plans to incur continued material capital expenditures for each of 2019 and 2020. 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. The Company is exposed to fluctuations in interest rates as its regulated ROE is derived using a formulaic approach that takes into account anticipated interest rates, but is not currently exposed to material commodity price risk. In the future, the Company may be exposed to additional foreign exchange risk in connection with other acquisitions or transactions in which it completes in a currency other than Canadian dollars. Although the Company may attempt to mitigate such risk through hedging transactions, there can be no assurance any such hedge will fully mitigate the risk of currency exchange fluctuations.

The OEB-approved adjustment formula for calculating ROE in a deemed regulatory capital structure of 60% debt and 40% equity provides for increases and decreases depending on changes in benchmark interest rates for Government of Canada debt and the A-rated utility corporate bond yield spread. The Company estimates that a decrease of 100 basis points in the

combination of the forecasted long-term Government of Canada bond yield and the A-rated utility corporate bond yield spread used in determining its rate of return would reduce the Company's transmission business' 2020 net income by approximately \$25 million. For the distribution business, after distribution rates are set as part of a Custom Incentive Rate application, the OEB does not expect to address annual rate applications for updates to allowed ROE, so fluctuations will have no impact to net income. The Company periodically utilizes interest rate swap agreements to mitigate elements of interest rate risk.

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. Derivative financial instruments result in exposure to credit risk, since there is a risk of counterparty default. Hydro One monitors and minimizes credit risk through various techniques, including dealing with highly rated counterparties, limiting total exposure levels with individual counterparties, entering into agreements which enable net settlement, and by monitoring the financial condition of counterparties. The Company does not trade in any energy derivatives. The Company is required to procure electricity on behalf of competitive retailers and certain local distribution companies for resale to their customers. The resulting concentrations of credit risk are mitigated through the use of various security arrangements, including letters of credit, which are incorporated into the Company's service agreements with these retailers in accordance with the OEB's Retail Settlement Code.

The failure to properly manage these risks could have a material adverse effect on the Company.

### Risks Relating to Asset Condition and Capital Projects

The Company continually incurs sustainment and development capital expenditures and monitors the condition of its 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. The connection of large numbers of generation facilities to the distribution network has resulted in greater than expected usage of some of the Company's equipment. This increases maintenance requirements and may accelerate the aging of the Company's assets.

Execution of the Company's capital expenditure programs, particularly for development capital expenditures, is partially dependent on external factors, such as environmental approvals, municipal permits, equipment outage schedules that accommodate the IESO, generators and transmission-connected customers, and supply chain availability for equipment suppliers and consulting services. There may also be a need for, among other things, *Environmental Assessment Act* (Ontario) approvals, approvals which require public meetings, appropriate engagement with Indigenous communities, OEB approvals of expropriation or early access to property, and other activities. Obtaining approvals and carrying out these processes may also be impacted by opposition to the proposed site of the capital investments. Delays in obtaining required approvals or failure to complete capital projects on a timely basis could materially adversely affect transmission reliability or customers' service quality or increase maintenance costs which could have a material adverse effect on the Company. Failure to receive approvals for projects when spending has already occurred would result

## Amended Management's Discussion and Analysis

in the inability of the Company to recover the investment in the project as well as forfeit the anticipated return on investment. The assets involved may be considered impaired and result in the write off of the value of the asset, negatively impacting net income. External factors are considered in the Company's planning process. If the Company is unable to carry out capital expenditure plans in a timely manner, equipment performance may degrade, which may reduce network capacity, result in customer interruptions, compromise the reliability of the Company's networks or increase the costs of operating and maintaining these assets. Any of these consequences could have a material adverse effect on the Company.

Increased competition for the development of large transmission projects and legislative changes relating to the selection of transmitters could impact the Company's ability to expand its existing transmission system, which may have an adverse effect on the Company. To the extent that other parties are selected to construct, own and operate new transmission assets, the Company's share of Ontario's transmission network would be reduced.

### Health, Safety and Environmental Risk

The Company is subject to provincial health and safety legislation. Findings of a failure to comply with this legislation could result in penalties and reputational risk, which could negatively impact the Company. The Company is subject to extensive Canadian federal, provincial and municipal environmental regulation. Failure to comply could subject the Company to fines or other penalties. In addition, the presence or release of hazardous or other harmful substances could lead to claims by third parties or governmental orders requiring the Company to take specific actions such as investigating, controlling and remediating the effects of these substances. Contamination of the Company's properties could limit its ability to sell or lease these assets in the future.

In addition, actual future environmental expenditures may vary materially from the estimates used in the calculation of the environmental liabilities on the Company's balance sheet. The Company does not have insurance coverage for these environmental expenditures.

There is also risk associated with obtaining governmental approvals, permits, or renewals of existing approvals and permits related to constructing or operating facilities. This may require environmental assessment or result in the imposition of conditions, or both, which could result in delays and cost increases. Failure to obtain necessary approvals or permits could result in an inability to complete projects.

Hydro One emits certain greenhouse gases, including sulphur hexafluoride or "SF<sub>6</sub>". There are increasing regulatory requirements and costs, along with attendant risks, associated with the release of such greenhouse gases, all of which could impose additional material costs on Hydro One.

Any regulatory decision to disallow or limit the recovery of such costs could have a material adverse effect on the Company.

### Pension Plan Risk

Hydro One has the Hydro One Defined Benefit Pension Plan in place for the majority of its employees. Contributions to the pension plan are established by actuarial valuations which are required to be filed with the Financial Services Commission of Ontario on a triennial basis. The most

recently filed valuation was prepared as at December 31, 2017, and was filed in April 2018, covering a three-year period from 2018 to 2020. Hydro One's contributions to its pension plan satisfy, and are expected to satisfy, minimum funding requirements. Contributions beyond 2020 will depend on the funded position of the plan, which is determined by investment returns, interest rates and changes in benefits and actuarial assumptions at that time. A determination by the OEB that some of the Company's pension expenditures are not recoverable through rates could have a material adverse effect on the Company, and this risk may be exacerbated if the amount of required pension contributions increases.

In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and other post-employment benefits (OPEB) amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently reports and recovers its pension expense on a cash basis, and maintains the accrual method with respect to OPEBs. Transitioning from the cash basis to an accrual method for pension may have material negative rate impacts for customers or material negative impacts on the company should recovery of costs be disallowed by the OEB. See " – Other Post-Employment and Post-Retirement Benefits Risks".

### Other Post-Employment and Post-Retirement Benefits Risks

The Company provides other post-employment and post-retirement benefits, including workers compensation benefits and long-term disability benefits to qualifying employees. In 2017, the OEB released a report establishing the use of the accrual accounting method as the default method on which to set rates for pension and OPEB amounts in cost-based applications, unless that method does not result in just and reasonable rates. Hydro One currently maintains the accrual accounting method with respect to OPEBs. If the OEB directed Hydro One to transition to a different accounting method for OPEBs, this could result in income volatility, due to an inability of the company to book the difference between the accrual and cash as a regulatory asset. A determination that some of the Company's post-employment and post-retirement benefit costs are not recoverable could have a material adverse effect on the Company.

### Risk Associated with Outsourcing Arrangements

Hydro One has entered into an outsourcing arrangement with a third party for the provision of back office and IT services. If the outsourcing arrangement or statements of work thereunder are terminated for any reason or expire before a new supplier is selected and fully transitioned, the Company could be required to transfer to another service provider or insource, which could have a material adverse effect on the Company's business, operating results, financial condition or prospects.

### Risk from Provincial Ownership of Transmission Corridors

The Province owns some of the corridor lands underlying the Company's transmission system. Although the Company has the statutory right to use these transmission corridors, the Company may be limited in its options to expand or operate its systems. Also, other uses of the transmission corridors by third parties in conjunction with the operation of the Company's systems may increase safety or environmental risks, which could have a material adverse effect on the Company.

### Litigation Risks

In the normal course of the Company's operations, it becomes involved in, is named as a party to and is the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions, relating to actual or alleged violations of law, common law damages claims, personal injuries, property damage, property taxes, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company, which could have a material adverse effect on the Company. Even if the Company prevails in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from the Company's business operations, which could adversely affect the Company. See also "Other Developments – Litigation – Class Action Lawsuit".

One of the four putative class action lawsuits commenced since the announcement of the Merger is still in existence, namely a putative class action lawsuit that has been filed by two Avista Corporation shareholders in Washington state court which names Hydro One, Olympus Holding Corp. and Olympus Corp. as defendants and alleges that they aided and abetted Avista Corporation's directors' breach of their fiduciary duties in connection with the Merger. The court issued an order staying the litigation until after the Merger has closed. Counsel for the plaintiffs in Fink has informally indicated that, in light of the termination of the Merger, the lawsuit will be dismissed, but no formal dismissal papers have been filed with the court at this time. The lawsuit and other potential legal proceedings could have an adverse impact on Hydro One. See also "Other Developments – Litigation – Litigation Relating to the Merger".

### Transmission Assets on Third-Party Lands Risk

Some of the lands on which the Company's transmission assets are located are owned by third parties, including the Province and federal Crown, and are or may become subject to land claims by First Nations. The Company requires valid occupation rights to occupy such lands (which may take the form of land use permits, easements or otherwise). If the Company does not have valid occupational rights on third-party owned or controlled lands or has occupational rights that are subject to expiry, it may incur material costs to obtain or renew such occupational rights, or if such occupational rights cannot be renewed or obtained it may incur material costs to remove and relocate its assets and restore the subject land. If the Company does not have valid occupational rights and must incur costs as a result, this could have a material adverse effect on the Company or otherwise materially adversely impact the Company's operations.

### Reputational, Public Opinion and Political Risk

Reputation risk is the risk of a negative impact to Hydro One's business, operations or financial condition that could result from a deterioration of Hydro One's reputation. Hydro One's reputation could be negatively impacted by changes in public opinion, attitudes towards the Company's privatization, failure to deliver on its customer promises and other external forces. Adverse reputational events or political actions could have negative impacts on Hydro One's business and prospects including, but not limited to, delays or denials of requisite approvals, such as denial of requested rates, and accommodations for Hydro One's planned projects, escalated costs, legal or regulatory action, and damage to stakeholder relationships.

### Risks Associated with Acquisitions

While the Company has experience in operating in the Ontario electricity market, if it were to pursue acquisitions in other markets it would need to develop or obtain additional expertise in these new markets. Such acquisitions would include inherent risks that some or all of the expected benefits may fail to materialize, or may not occur within the time periods anticipated, and Hydro One may incur material unexpected costs. Realization of the anticipated benefits 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 Company's Relationship with the Province

#### Ownership and Continued Influence by the Province and Voting Power; Share Ownership Restrictions

The Province currently owns approximately 47.4% of the outstanding common shares of Hydro One. The Electricity Act restricts the Province from selling voting securities of Hydro One (including common shares) of any class or series if it would own less than 40% of the outstanding number of voting securities of that class or series after the sale and in certain circumstances also requires the Province to take steps to maintain that level of ownership. Accordingly, the Province is expected to continue to maintain a significant ownership interest in voting securities of Hydro One for an indefinite period.

As a result of its significant ownership of the common shares of Hydro One, the Province has, and is expected indefinitely to have, the ability to determine or significantly influence the outcome of shareholder votes, subject to the restrictions in the Governance Agreement. 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 taken by the Province following the provincial election in June 2018, 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](http://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 pension benefit liability, deferred income tax liabilities, post-retirement and post-employment benefit liability, share-based compensation costs, forgone revenue, and environmental liabilities. The Company's regulatory liabilities represent certain amounts that are refundable to future electricity customers, and pertain primarily to OEB deferral and variance accounts. The regulatory assets and liabilities can be recognized for rate-setting and financial reporting purposes only if the amounts have been approved for inclusion in the electricity rates by the OEB, or if such approval is judged to be probable by management. If management judges that it is no longer probable that

the OEB will allow the inclusion of a regulatory asset or liability in future electricity rates, the applicable carrying amount of the regulatory asset or liability will be reflected in results of operations in the period that the judgment is made by management.

### Environmental Liabilities

Hydro One records a liability for the estimated future expenditures associated with the removal and destruction of 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, 2018 increased to 3.90% (from 3.40% at December 31, 2017) for pension benefits and increased to 4.00% (from 3.40% at December 31, 2017) for the post-retirement and post-employment plans. The increase in the discount rate has resulted in a corresponding decrease 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 6.50% is based on expectations of long-term rates of return at the beginning of the year and reflects a pension asset mix consistent with the pension plan's investment policy effective November 11, 2016. A new investment policy was adopted by Hydro One effective May 14, 2018 which will be implemented over the next several years. Hydro One's current expectation is that the new investment policy will not be fully implemented until 2021-2022. As such, with the implementation timing noted above, the investment policy effective November 11, 2016 would continue to be appropriate for the December 31, 2018 disclosures and the 2019 registered pension plan expense.

Rates of return on the respective portfolios are determined with reference to respective published market indices. The expected rate of return on pension plan assets reflects the Company's long-term expectations. The Company believes that this assumption is reasonable because, with the pension plan's balanced investment approach, the higher volatility of equity investment returns is intended to be offset by the greater stability of fixed-income and short-term investment returns. The net result, on a long-term basis, is a lower return than might be expected by investing in equities alone. In the short term, the pension plan can experience fluctuations in actual rates of return.

### Rate of Cost of Living Increase

The rate of cost of living increase is determined by considering differences between long-term Government of Canada nominal bonds and real return bonds, which decreased from 1.60% per annum as at December 31, 2017 to approximately 1.40% per annum as at December 31, 2018. Given the Bank of Canada's commitment to keep long-term inflation between 1.00% and 3.00%, management believes that the current rate is reasonable to use as a long-term assumption and as such, has used a 2.0% per annum inflation rate for employee future benefits liability valuation purposes as at December 31, 2018.

### 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.

### 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, 2018 is 95% of 2014 Canadian Pensioners Mortality Private Sector table projected generationally using improvement Scale B.

### Rate of Increase in Health Care Cost Trends

The costs of post-retirement and post-employment benefits are determined at the beginning of the year and are based on assumptions for expected claims experience and future health care cost inflation. For the post-retirement benefit plans, a trend study of historical Hydro One experience was conducted in 2017, which resulted in a change in the prescription drug, dental and hospital trends used for 2017 and 2018 year-end reporting purposes. A 1% increase in the health care cost trends would result in a \$23 million increase in 2018 interest cost plus service cost, and a \$230 million increase in the benefit liability at December 31, 2018.

### Valuation of Deferred Tax Assets

Hydro One assesses the likelihood of realizing deferred tax assets by reviewing all readily available current and historical information, including a forecast of future taxable income. To the extent management considers it is more likely than not that some portion or all of the deferred tax assets will not be realized, a valuation allowance is recognized.

### Asset Impairment

Within Hydro One's regulated businesses, the carrying costs of most of the long-lived assets are included in the rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through OEB-approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable. The Company regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. As at December 31, 2018, no asset impairment had been recorded for assets within Hydro One's regulated or unregulated businesses.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. Hydro One has concluded that goodwill was not impaired at December 31, 2018. Goodwill represents the cost of acquired distribution and transmission companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date.

## DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

Disclosure controls and procedures are 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, 2018.

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, 2018.

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, 2018 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
ASC 606	May 2014 – November 2017	ASC 606 <i>Revenue from Contracts with Customers</i> replaced ASC 605 <i>Revenue Recognition</i> . ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.	January 1, 2018	On January 1, 2018, Hydro One adopted ASC 606 using the retrospective method, without the election of any practical expedients. Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the disclosure requirements of ASC 606 for annual and interim periods in the year of adoption.
ASU 2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 – Significant Accounting Policies and Note 12 – Regulatory Assets and Liabilities.

### Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Anticipated impact on Hydro One
2016-02 2018-01 2018-10 2018-11 2018-20	February 2016 – December 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties.	January 1, 2019	Hydro One reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Company will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Company will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to Hydro One's financial statements will be the recognition of approximately \$27 million Right-of-Use (ROU) assets and corresponding lease obligations on the Consolidated Balance Sheet. The ROU assets and lease obligations represent the present value of the Company's remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU assets and lease obligations correspond to the Company's incremental borrowing rate.

## Amended Management's Discussion and Analysis

Guidance	Date issued	Description	Effective date	Anticipated impact on Hydro One
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
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	Under assessment
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
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, 2020	Under assessment

**SUMMARY OF FOURTH QUARTER RESULTS OF OPERATIONS**

Three months ended December 31 (millions of dollars, except EPS)	2018	2017	Change
<b>Revenues</b>			
Distribution	1,138	1,049	8.5%
Transmission	342	379	(9.8%)
Other	11	11	0.0%
	1,491	1,439	3.6%
<b>Costs</b>			
Purchased power	741	662	11.9%
OM&A			
Distribution	167	146	14.4%
Transmission	114	79	44.3%
Other	27	19	42.1%
	308	244	26.2%
Depreciation, amortization and asset removal costs	217	214	1.4%
	1,266	1,120	13.0%
<b>Income before financing charges and income taxes</b>	225	319	(29.5%)
Financing charges	123	119	3.4%
<b>Income before income taxes</b>	102	200	(49.0%)
Income taxes	800	38	2,005.3%
<b>Net income (loss)</b>	(698)	162	(530.9%)
<b>Net income (loss) attributable to common shareholders of Hydro One</b>	(705)	155	(554.8%)
Basic EPS	\$ (1.18)	\$ 0.26	(553.8%)
Diluted EPS	\$ (1.18)	\$ 0.26	(553.8%)
Basic Adjusted EPS	\$ 0.30	\$ 0.29	3.4%
Diluted Adjusted EPS	\$ 0.29	\$ 0.28	3.6%
<b>Capital Investments</b>			
Distribution	168	161	4.3%
Transmission	292	267	9.4%
Other	7	3	133.3%
	467	431	8.4%
<b>Assets Placed In-Service</b>			
Distribution	253	207	22.2%
Transmission	698	522	33.7%
Other	1	4	(75.0%)
	952	733	29.9%

**Net Income (Loss)**

Net loss attributable to common shareholders for the quarter ended December 31, 2018 of \$705 million is a decrease of \$860 million or 554.8% from the prior year net income. Significant influences on earnings included:

- increase in transmission and distribution revenues due to higher energy consumption resulting from favourable weather;
- higher transmission revenues driven by increased OEB-approved transmission rates;
- higher OM&A costs primarily resulting from:
  - higher vegetation management costs resulting from a change to an improved vegetation program resulting in greater coverage and better reliability,
  - higher property taxes, primarily due to non-recurring favourable re-assessment of payments in lieu of property taxes in 2017,

- higher stations and lines maintenance costs,
- insurance proceeds received in Q4 2017,
- higher HST recovery in 2017, and
- higher costs related to the Merger;

- higher income tax expense primarily attributable to a charge to deferred tax expense of \$799 million related to the OEB's deferred tax asset and distribution rates decisions, partially offset by higher temporary differences arising from a combination of higher in-service additions, the asset mix and higher pension and OPEB contributions in excess of accounting expense in the fourth quarter of 2018, compared to 2017.

**EPS and Adjusted EPS**

EPS was (\$1.18) for the fourth quarter of 2018, compared to \$0.26 in 2017. The decrease in EPS was driven by lower earnings for the fourth quarter of 2018, as discussed above. Adjusted EPS was \$0.30 in the fourth quarter

## Amended Management's Discussion and Analysis

of 2018, compared to \$0.29 in 2017. The increase in Adjusted EPS was driven by higher net income for the fourth quarter of 2017, net of impacts related to the Merger and the impacts related to the OEB's deferred tax asset decision on Hydro One Networks' distribution and transmission businesses.

### Revenues

The quarterly decrease of \$37 million or 9.8% in transmission revenues was primarily due to impacts of the OEB's deferred tax asset decision, partially offset by higher revenues driven by increased OEB-approved transmission rates for 2018, and higher average monthly Ontario 60-minute peak demand driven by favourable weather in the fourth quarter of 2018.

The quarterly increase of \$10 million or 2.6% in distribution revenues, net of purchased power, was primarily due to higher energy consumption resulting from favourable weather in the fourth quarter of 2018 and higher deferred regulatory adjustments; partially offset by lower CDM revenue.

### OM&A Costs

The quarterly increase of \$35 million or 44.3% in transmission OM&A costs was primarily due to a non-recurring reduction of provision for payments in lieu of property taxes following a favourable reassessment of the regulation in 2017, higher volume of demand maintenance work on power equipment and overhead lines, insurance proceeds received in 2017 due to equipment failures at the Fairchild and Campbell transmission stations, and higher volume of work on vegetation management.

The quarterly increase of \$21 million or 14.4% in distribution OM&A costs was primarily due to higher volume of work on vegetation management, and higher volume of emergency calls, partially offset by lower storm restoration costs, and lower costs related to the renewed IT contract.

A further increase of \$8 million in other OM&A is driven primarily by higher costs related to the Merger.

### Financing Charges

The quarterly increase of \$4 million or 3.4% in financing charges was primarily due to an increase in interest expense on long-term debt resulting from an increase in weighted-average long-term debt balance outstanding during the quarter, partially offset by an unrealized loss recorded in 2017 due to revaluation of the foreign exchange contract related to the Merger.

### Income Taxes

Income tax expense for the fourth quarter of 2018 increased by \$762 million compared to 2017, and the Company realized an ETR of approximately 784.3% in the fourth quarter of 2018, compared to approximately 19.0% realized in 2017. This was primarily attributable to a charge to deferred tax expense of \$799 million related to the OEB's deferred tax asset and distribution rates decisions (see section "Regulation – Electricity Rates Applications – Hydro One Networks – Transmission" for details). This increase was partially offset by an increase in tax deductions arising from higher in-service additions coupled with an increased allocation to a higher depreciation class, as well as higher pension and other post-employment benefit (OPEB) contributions for tax purposes. The Company is required to accrue taxes based on the tax liability without considering the temporary differences as prescribed by the regulator.

### Assets Placed In-Service

The increase in transmission assets placed in-service during the fourth quarter was primarily due to the following:

- assets placed in-service in the fourth quarter of 2018 for station sustainment investments, including Horning, Centralia, London Nelson, St. Isidore, Wanstead, Palmerston, Chenuaux, and Dryden transmission stations, as well as the Bruce Special Protection System end-of-life equipment replacement project;
- higher volume of demand work placed in-service associated with equipment failures; and
- higher volume of overhead lines and component replacement work placed in-service; partially offset by
- substantial investments in major development projects placed in-service in 2017, including Leamington and Holland transmission stations; and
- assets placed in-service in the fourth quarter of 2017 for station sustainment investments, including OverBrook, Hanmer, and Leaside transmission stations.

The increase in distribution assets placed in-service during the fourth quarter was primarily due to the following:

- timing of investments placed in-service for system capability reinforcement projects;
- cumulative investments in the Advanced Distribution System project placed in-service in 2018; and
- cumulative investments in distribution generation connection projects placed in-service in 2018; partially offset by
- the completion of the Company's website redesign project to improve customer service and operational efficiencies; and
- timing of demand work on large joint-use and line relocation projects.

### Capital Investments

The increase in transmission capital investments during the fourth quarter was primarily due to the following:

- higher volume of overhead lines refurbishments and replacements;
- higher volume of demand work associated with equipment failures;
- higher volume of work required to adhere to the NERC Cyber Security standards;
- timing of project work on major development projects, including the Niagara Reinforcement, Lake Superior Link, and East-West Tie Connection projects, as well as work at Clarington and Holland transmission stations; and
- higher volume of spare transformer purchases; partially offset by
- lower volume of transmission station refurbishments and replacements work.

The increase in distribution capital investments during the fourth quarter was primarily due to the following:

- higher spend on joint use and line relocation projects due to timing of capital contributions; and
- increased volume of emergency power and storm restorations work due to higher storm activity in 2018.

## HYDRO ONE HOLDINGS LIMITED – UNAUDITED 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 November 23, 2018. 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, 2018 and December 31, 2017 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.

For the year ended December 31 (millions of dollars, unaudited)	Hydro One Limited		HOHL		Subsidiaries of Hydro One Limited, other than HOHL		Consolidating Adjustments		Total Consolidated Amounts of Hydro One Limited	
	2018	2017	2018	2017	2018	2017	2018	2017	2018	2017
	Revenue	12	16	—	—	6,243	6,053	(105)	(79)	6,150
Net Income (Loss) Attributable to Common Shareholders	(74)	(43)	22	(3)	47	745	(84)	(41)	(89)	658

As at December 31 (millions of dollars, unaudited)	Hydro One Limited		HOHL		Subsidiaries of Hydro One Limited, other than HOHL		Consolidating Adjustments		Total Consolidated Amounts of Hydro One Limited	
	2018	2017	2018	2017	2018	2017	2018	2017	2018	2017
	Current Assets	159	117	22	—	2,054	1,444	(744)	(542)	1,491
Non-Current Assets	5,799	6,423	—	—	41,597	41,745	(23,230)	(23,486)	24,166	24,682
Current Liabilities	97	83	—	3	4,391	3,933	(1,460)	(1,279)	3,028	2,740
Non-Current Liabilities	1,516	1,514	3	—	22,373	21,403	(10,906)	(10,209)	12,986	12,708

## FORWARD-LOOKING STATEMENTS AND INFORMATION

The Company's oral and written public communications, including this document, often contain forward-looking statements that are based on current expectations, estimates, forecasts and projections about the Company's business and the industry, regulatory and economic environments in which it operates, and include beliefs and assumptions made by the management of the Company. Such statements include, but are not limited to, statements regarding: the Company's transmission and distribution rate applications, including resulting decisions, rates and expected impacts and timing; the Company's liquidity and capital resources and operational requirements; the Operating Credit Facilities; expectations regarding the Company's financing activities; the Company's maturing debt; ongoing and planned projects and initiatives, including expected results and completion dates; expected future capital investments, including expected timing and investment plans; contractual obligations and other commercial commitments; expectations regarding the deferred tax asset; the Appeal; the OEB; the Exemptive Relief; NRLP and the Niagara Reinforcement Project, the Lake Superior Link Project, and related regulatory applications; the Company's share capital and conversion of outstanding awards under the share grant plans and the LTIP; collective agreements; the pension plan, future pension contributions, valuations and expected impacts; impacts of OEB treatment of post-employment benefit costs; dividends; credit ratings and related risks; Hydro One's strategy; effect of interest rates; non-GAAP measures; critical accounting estimates, including environmental liabilities, regulatory assets and liabilities, and employee future benefits; occupational

rights; internal control over financial reporting and disclosure; recent accounting-related guidance; the Universal Base Shelf Prospectus; the US Debt Shelf Prospectus; the Demand Facility; the Company's acquisitions and mergers, including Orillia Power and Peterborough Distribution; expected outcomes and impacts relating to the termination of the Merger; the Urgent Priorities Act, the Accountability Act, and anticipated impacts; Hydro One's new compensation framework; expectations relating to executive compensation and potential impacts on Hydro One; anticipated and potential senior management departures and possible impacts; retention arrangements; the Company's ability to attract and retain qualified officers; risk associated with acquisitions; anticipated impact of measures related to accelerated investment initiatives; climate change; cyber and data security; expectations related to work force demographics; class action litigation, including litigation relating to the Merger; foreign exchange risk; the Province's ownership of Hydro One, and conflicts that may arise between the Province and Hydro One from time to time; government actions and the potential impacts on Hydro One and its business; future sales of shares of Hydro One; and reputational, public opinion and political risk. Words such as "expect", "anticipate", "intend", "attempt", "may", "plan", "will", "believe", "seek", "estimate", "goal", "aim", "target", and variations of such words and similar expressions are intended to identify such forward-looking statements. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking statements. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking statements, except as required by law.

## Amended Management's Discussion and Analysis

These forward-looking statements are based on a variety of factors and assumptions including, but not limited to, the following: no unforeseen changes in the legislative and operating framework for Ontario's electricity market 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; and no significant event occurring outside the ordinary course of business. These assumptions are based on information currently available to the Company, including information obtained from third party sources. Actual results may differ materially from those predicted by such forward-looking statements. While Hydro One does not know what impact any of these differences may have, the Company's business, results of operations, financial condition and credit stability may be materially adversely affected. Factors that could cause actual results or outcomes to differ materially from the results expressed or implied by forward-looking statements include, among other things:

- risks associated with the Province's share ownership of Hydro One and other relationships with the Province, including potential conflicts of interest that may arise between Hydro One, the Province and related parties;
- regulatory risks and risks relating to Hydro One's revenues, including risks relating to rate orders, actual performance against forecasts and capital expenditures, or denials of applications;
- the risk that the Company may be unable to comply with regulatory and legislative requirements or that the Company may incur additional costs for compliance that are not recoverable through rates;
- the risk of exposure of the Company's facilities to the effects of severe weather conditions, natural disasters or other unexpected occurrences for which the Company is uninsured or for which the Company could be subject to claims for damage;
- public opposition to and delays or denials of the requisite approvals and accommodations for the Company's planned projects;
- risks associated with the Province exercising further legislative and regulatory powers in the implementation of the Urgent Priorities Act and the Accountability Act;
- the risk that Hydro One may incur significant costs associated with transferring assets located on reserves (as defined in the Indian Act (Canada));
- the risks associated with information system security and maintaining a complex IT system infrastructure;
- the risk of labour disputes and inability to negotiate appropriate collective agreements on acceptable terms consistent with the Company's rate decisions;
- the risks related to the Company's work force demographic and its potential inability to attract and retain qualified personnel;
- risk that the Company is not able to arrange sufficient cost-effective financing to repay maturing debt and to fund capital expenditures;
- the risk of a credit rating downgrade and its impact on the Company's funding and liquidity;
- risks associated with fluctuations in interest rates and failure to manage exposure to credit risk;
- the risk that the Company may not be able to execute plans for capital projects necessary to maintain the performance of the Company's assets or to carry out projects in a timely manner;
- the risk of non-compliance with environmental regulations or failure to mitigate significant health and safety risks and inability to recover environmental expenditures in rate applications;
- the risk that assumptions that form the basis of the Company's recorded environmental liabilities and related regulatory assets may change;
- the risk of not being able to recover the Company's pension expenditures in future rates and uncertainty regarding the future regulatory treatment of pension, other post-employment benefits and post-retirement benefits costs;
- the potential that Hydro One may incur significant expenses to replace functions currently outsourced if agreements are terminated or expire before a new service provider is selected;
- the risks associated with economic uncertainty and financial market volatility;
- the inability to prepare financial statements using US GAAP;
- the impact of the ownership by the Province of lands underlying the Company's transmission system; and
- the risk related to the impact of the 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 "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](http://www.sedar.com) and the Company's website at [www.HydroOne.com/Investors](http://www.HydroOne.com/Investors).

## Management's Report

The Amended 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 Amended 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 Amended 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 Amended Consolidated Financial Statements. The preparation of the Amended 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, 2018. 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 Amended 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 fulfills its responsibilities for financial reporting and internal control over reporting and disclosure. The Audit Committee of Hydro One met periodically with management, the internal auditors and the external auditors to satisfy itself that each group had properly discharged its respective responsibility and to review the Amended 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:



**Paul Dobson**  
Acting President and  
Chief Executive Officer



**Christopher Lopez**  
Acting Chief Financial Officer

# Report of Independent Registered Public Accounting Firm

## To the Shareholders and Board of Directors of Hydro One Limited

### Opinion on the Amended Consolidated Financial Statements

We have audited the accompanying amended consolidated balance sheet of Hydro One Limited (the Company) as of December 31, 2018, the related amended consolidated statements of operations and comprehensive income, changes in equity, and cash flows for the year then ended, and the related amended notes (collectively, the amended consolidated financial statements). In our opinion, the amended consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows for the year then ended, in conformity with US generally accepted accounting principles.

### Basis for Opinion

These amended consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these amended consolidated financial statements based on our audit. 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 US federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit 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 audit, 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 audit included performing procedures to assess the risks of material misstatement of the amended 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 amended consolidated financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the amended consolidated financial statements. We believe that our audit provides a reasonable basis for our opinion.



Chartered Professional Accountants, Licensed Public Accountants

We have served as the Company's auditor since 2008

Toronto, Canada  
March 25, 2019

# Independent Auditors' Report

## To the Shareholders and Board of Directors of Hydro One Limited

We have audited the accompanying consolidated financial statements of Hydro One Limited, which comprise the consolidated balance sheet as at December 31, 2017, the consolidated statements of operations and comprehensive income, changes in equity, and cash flows for the year then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

## Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with US generally accepted accounting principles, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

## Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audit. We conducted our audit in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

## Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Hydro One Limited as at December 31, 2017, and its consolidated results of operations and its consolidated cash flows for the year then ended in accordance with US generally accepted accounting principles.



Chartered Professional Accountants, Licensed Public Accountants

Toronto, Canada  
March 25, 2019

## Amended Consolidated Statements of Operations and Comprehensive Income (Loss)

Year ended December 31 (millions of Canadian dollars, except per share amounts)	2018	2017
<b>Revenues</b>		
Distribution (includes \$280 related party revenues; 2017 – \$284) (Note 27)	4,422	4,366
Transmission (includes \$1,617 related party revenues; 2017 – \$1,523) (Note 27)	1,686	1,578
Other	42	46
	6,150	5,990
<b>Costs</b>		
Purchased power (includes \$1,648 related party costs; 2017 – \$1,594) (Note 27)	2,899	2,875
Operation, maintenance and administration (Note 27)	1,105	1,066
Depreciation, amortization and asset removal costs (Note 5)	837	817
	4,841	4,758
<b>Income before financing charges and income taxes</b>	1,309	1,232
Financing charges (Note 6)	459	439
<b>Income before income taxes</b>	850	793
Income taxes (Note 7)	915	111
<b>Net income (loss)</b>	(65)	682
Other comprehensive income	4	1
<b>Comprehensive income (loss)</b>	(61)	683
<b>Net income (loss) attributable to:</b>		
Noncontrolling interest (Note 26)	6	6
Preferred shareholders	18	18
Common shareholders	(89)	658
	(65)	682
<b>Comprehensive income attributable to:</b>		
Noncontrolling interest (Note 26)	6	6
Preferred shareholders	18	18
Common shareholders	(85)	659
	(61)	683
<b>Earnings per common share (Note 24)</b>		
Basic	\$ (0.15)	\$ 1.11
Diluted	\$ (0.15)	\$ 1.10
<b>Dividends per common share declared (Note 23)</b>	\$ 0.91	\$ 0.87

See accompanying notes to Amended Consolidated Financial Statements.

# Amended Consolidated Balance Sheets

December 31 (millions of Canadian dollars)	2018	2017
<b>Assets</b>		
Current assets:		
Cash and cash equivalents	483	25
Accounts receivable (Note 8)	628	636
Due from related parties (Note 27)	255	253
Other current assets (Note 9)	125	105
	1,491	1,019
Property, plant and equipment (Note 10)	20,687	19,947
Other long-term assets:		
Regulatory assets (Note 12)	1,721	3,049
Deferred income tax assets (Note 7)	1,018	987
Intangible assets (Note 11)	410	369
Goodwill	325	325
Other assets	5	5
	3,479	4,735
<b>Total assets</b>	<b>25,657</b>	<b>25,701</b>
<b>Liabilities</b>		
Current liabilities:		
Short-term notes payable (Note 15)	1,252	926
Long-term debt payable within one year (Notes 15, 17)	731	752
Accounts payable and other current liabilities (Note 13)	956	905
Due to related parties (Note 27)	89	157
	3,028	2,740
Long-term liabilities:		
Long-term debt (includes \$845 measured at fair value; 2017 – \$541) (Notes 15, 17)	9,978	9,315
Convertible debentures (Notes 16, 17)	489	487
Regulatory liabilities (Note 12)	326	128
Deferred income tax liabilities (Note 7)	58	71
Other long-term liabilities (Note 14)	2,135	2,707
	12,986	12,708
<b>Total liabilities</b>	<b>16,014</b>	<b>15,448</b>
<i>Contingencies and Commitments</i> (Notes 29, 30)		
<i>Subsequent Events</i> (Note 4, 16, 17, 32)		
Noncontrolling interest subject to redemption (Note 26)	21	22
<b>Equity</b>		
Common shares (Note 22)	5,643	5,631
Preferred shares (Note 22)	418	418
Additional paid-in capital (Note 25)	56	49
Retained earnings	3,459	4,090
Accumulated other comprehensive loss	(3)	(7)
Hydro One shareholders' equity	9,573	10,181
Noncontrolling interest (Note 26)	49	50
<b>Total equity</b>	<b>9,622</b>	<b>10,231</b>
	<b>25,657</b>	<b>25,701</b>

See accompanying notes to Amended Consolidated Financial Statements.

On behalf of the Board of Directors:



Tom Woods  
Chair



William Sheffield  
Chair, Audit Committee

## Amended Consolidated Statements of Changes in Equity

Year ended December 31, 2018 (millions of Canadian dollars)	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholders' Equity	Non- controlling Interest (Note 26)	Total Equity
January 1, 2018	5,631	418	49	4,090	(7)	10,181	50	10,231
Net income (loss)	—	—	—	(71)	—	(71)	4	(67)
Other comprehensive income	—	—	—	—	4	4	—	4
Distributions to noncontrolling interest	—	—	—	—	—	—	(5)	(5)
Dividends on preferred shares	—	—	—	(18)	—	(18)	—	(18)
Dividends on common shares	—	—	—	(542)	—	(542)	—	(542)
Common shares issued	12	—	(12)	—	—	—	—	—
Stock-based compensation (Note 25)	—	—	19	—	—	19	—	19
<b>December 31, 2018</b>	<b>5,643</b>	<b>418</b>	<b>56</b>	<b>3,459</b>	<b>(3)</b>	<b>9,573</b>	<b>49</b>	<b>9,622</b>
Year ended December 31, 2017 (millions of Canadian dollars)	Common Shares	Preferred Shares	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Hydro One Shareholders' Equity	Non- controlling Interest (Note 26)	Total Equity
January 1, 2017	5,623	418	34	3,950	(8)	10,017	50	10,067
Net income	—	—	—	676	—	676	4	680
Other comprehensive income	—	—	—	—	1	1	—	1
Distributions to noncontrolling interest	—	—	—	—	—	—	(4)	(4)
Dividends on preferred shares	—	—	—	(18)	—	(18)	—	(18)
Dividends on common shares	—	—	—	(518)	—	(518)	—	(518)
Common shares issued	8	—	(8)	—	—	—	—	—
Stock-based compensation (Note 25)	—	—	23	—	—	23	—	23
<b>December 31, 2017</b>	<b>5,631</b>	<b>418</b>	<b>49</b>	<b>4,090</b>	<b>(7)</b>	<b>10,181</b>	<b>50</b>	<b>10,231</b>

See accompanying notes to Amended Consolidated Financial Statements.

## Amended Consolidated Statements of Cash Flows

Year ended December 31 (millions of Canadian dollars)	2018	2017
<b>Operating activities</b>		
Net income (loss)	(65)	682
Environmental expenditures	(22)	(24)
Adjustments for non-cash items:		
Depreciation and amortization (Note 5)	747	727
Regulatory assets and liabilities	35	112
Deferred income taxes	890	85
Unrealized loss (gain) on foreign exchange contract	(25)	3
Other	38	18
Changes in non-cash balances related to operations (Note 28)	(23)	113
<b>Net cash from operating activities</b>	<b>1,575</b>	<b>1,716</b>
<b>Financing activities</b>		
Long-term debt issued	1,400	—
Long-term debt repaid	(753)	(602)
Short-term notes issued	4,242	3,795
Short-term notes repaid	(3,916)	(3,338)
Convertible debentures issued (Note 16)	—	513
Dividends paid	(560)	(536)
Distributions paid to noncontrolling interest	(8)	(6)
Other (Note 16)	(6)	(27)
<b>Net cash from (used in) financing activities</b>	<b>399</b>	<b>(201)</b>
<b>Investing activities</b>		
Capital expenditures (Note 28)		
Property, plant and equipment	(1,418)	(1,467)
Intangible assets	(120)	(80)
Capital contributions received (Note 28)	7	9
Other	15	(2)
<b>Net cash used in investing activities</b>	<b>(1,516)</b>	<b>(1,540)</b>
<b>Net change in cash and cash equivalents</b>	<b>458</b>	<b>(25)</b>
Cash and cash equivalents, beginning of year	25	50
<b>Cash and cash equivalents, end of year</b>	<b>483</b>	<b>25</b>

See accompanying notes to Amended Consolidated Financial Statements.

# Notes to Amended Consolidated Financial Statements

For the years ended December 31, 2018 and 2017

## 1. DESCRIPTION OF THE BUSINESS

Hydro One Limited (Hydro One or the Company) was incorporated on August 31, 2015, under the *Business Corporations Act* (Ontario). On October 31, 2015, the Company acquired Hydro One Inc., a company previously wholly-owned by the Province of Ontario (Province). The acquisition of Hydro One Inc. by Hydro One was accounted for as a common control transaction and Hydro One is a continuation of business operations of Hydro One Inc. At December 31, 2018, the Province held approximately 47.4% (2017 – 47.4%) 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) in respect of the Bruce-to-Milton transmission line. Hydro One's distribution business consists of the distribution system operated by Hydro One Inc.'s subsidiaries, Hydro One Networks and Hydro One Remote Communities Inc. (Hydro One Remote Communities).

### Ontario Energy Board (OEB) March 7, 2019 Decisions and Amended Consolidated Financial Statements

Subsequent to year end, 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 requirements dated September 28, 2017 (Original Decision) 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* (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.

The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under United States (US) Generally Accepted Accounting Principles (GAAP) and as such the Company is required to update the consolidated financial statements previously issued on February 20, 2019, to reflect the subsequent event in connection with filing its annual report on Form 40-F with the US Securities and Exchange Commission, so that they reflect events to the date of approval of the Form 40-F. As a result, the financial impact of this OEB decision has been reflected in these amended consolidated financial statements, as more fully discussed in Note 12 – Regulatory Assets and Liabilities.

### Transmission

In December 2017, the OEB approved Hydro One Networks' 2018 rates revenue requirement of \$1,511 million. See Note 12 – Regulatory Assets and Liabilities for additional information.

In December 2015, the OEB approved B2M LP's 2015-2019 rates revenue requirements of \$39 million, \$36 million, \$37 million, \$38 million and \$37 million for the respective years. On May 10, 2018, the OEB issued its decision and rate order on B2M LP's 2018 transmission application reflecting revenue requirement of \$36 million, effective January 1, 2018.

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. In September 2017, the OEB issued its decision and Order on HOSSM's 2017 transmission rate application, denying the requested revenue requirement. HOSSM's 2016 approved revenue requirement of \$41 million remained in effect for 2017 and 2018.

### Distribution

In March 2017, Hydro One Networks filed an application with the OEB for 2018-2022 distribution rates. The requested revenue requirements, updated in June 2018, are \$1,514 million for 2018, \$1,561 million for 2019, \$1,607 million for 2020, \$1,681 million for 2021, and \$1,722 million for 2022. The OEB decision was received on March 7, 2019. See Note 32(D) – Subsequent Events – OEB Regulatory Decisions.

On November 17, 2017, Hydro One filed with the OEB a request for 2018 interim rates based on 2017 OEB-approved rates, adjusted for an updated load forecast. On December 1, 2017, the OEB denied this request and set interim 2018 rates based on 2017 OEB-approved rates with no adjustments.

On August 28, 2017, Hydro One Remote Communities filed an application with the OEB seeking approval of its 2018 revenue requirement of \$57 million and electricity rates effective May 1, 2018. On March 19, 2018, the OEB approved the settlement agreement related to the 2018 rates application reached by Hydro One Remote Communities and the intervenors in the rate proceeding. On March 26, 2018, a draft rate order was filed with the OEB for 2018 rates. The OEB approved the draft rate order on April 12, 2018, and the new rates were implemented effective May 1, 2018.

## 2. SIGNIFICANT ACCOUNTING POLICIES

### Basis of Consolidation

These Amended Consolidated Financial Statements (Consolidated Financial Statements) include the accounts of the Company and its subsidiaries. Intercompany transactions and balances have been eliminated.

### Basis of Accounting

These Consolidated Financial Statements are prepared and presented in accordance with US 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.

## Notes to Amended Consolidated Financial Statements

Management evaluates these estimates on an ongoing basis based upon historical experience, current conditions, and assumptions believed to be reasonable at the time the assumptions are made, with any adjustments being recognized in results of operations in the period they arise. Significant estimates relate to regulatory assets and regulatory liabilities, environmental liabilities, pension benefits, post-retirement and post-employment benefits, asset retirement obligations, goodwill and asset impairments, contingencies, unbilled revenues, and deferred income tax assets and liabilities. Actual results may differ significantly from these estimates.

### 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 Type I subsequent event.

### 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

The Company adopted Accounting Standard Codification (ASC) 606 – *Revenue from Contracts with Customers* on January 1, 2018 using the retrospective method, without the election of any practical expedients. There was no material impact to the Company's revenue recognition policy as a result of adopting ASC 606, and no adjustments were made to prior period reported financial statements amounts.

### Nature of Revenues

Transmission revenues predominantly consist of transmission tariffs, which are collected through OEB-approved Uniform Transmission Rates (UTR) and the monthly peak demand for electricity across Hydro One's high-voltage network. OEB-approved UTR is 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. Overdue amounts related to regulated billings bear interest at OEB-approved rates. The allowance for doubtful accounts reflects the Company's best estimate of losses on billed accounts receivable balances. The Company estimates the allowance for doubtful accounts on billed accounts receivable by applying internally developed loss rates to the outstanding receivable balances by aging category. Loss rates applied to the billed accounts receivable balances are based on historical overdue balances, customer payments and write-offs. Accounts receivable are written-off against the allowance when they are deemed uncollectible. The allowance for doubtful accounts is affected by changes in volume, prices and economic conditions.

### Noncontrolling interest

Noncontrolling interest represents the portion of equity ownership in subsidiaries that is not attributable to shareholders of Hydro One. Noncontrolling interest is initially recorded at fair value and subsequently the amount is adjusted for the proportionate share of net income and other comprehensive income (OCI) attributable to the noncontrolling interest and any dividends or distributions paid to the noncontrolling interest.

If a transaction results in the acquisition of all, or part, of a noncontrolling interest in a subsidiary, the acquisition of the noncontrolling interest is accounted for as an equity transaction. No gain or loss is recognized in consolidated net income or comprehensive income as a result of changes in the noncontrolling interest, unless a change results in the loss of control by the Company.

### Income Taxes

Current and deferred income taxes are computed based on the tax rates and tax laws enacted as at the balance sheet date. Tax benefits associated with income tax positions are recorded only when the more-likely-than-not recognition threshold is satisfied and are measured at the largest amount of benefit that has a greater than 50% likelihood of being realized upon settlement. Management evaluates each position based solely on the technical merits and facts and circumstances of the position, assuming the position will be examined by a taxing authority having full knowledge of all relevant information. Significant management judgment is required to determine recognition thresholds and the related amount of tax benefits to be recognized in the Consolidated Financial Statements. Management re-evaluates tax positions each period using new information about recognition or measurement as it becomes available.

### Deferred Income Taxes

Deferred income taxes are provided for using the liability method. Under this method, deferred income tax 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 Consolidated Statements of Operations and Comprehensive Income.

Management reassesses the deferred income tax assets at each balance sheet date and reduces the amount to the extent that it is more-likely-than-not that the deferred income tax asset will not be realized. Previously unrecognized deferred income tax assets are reassessed at each balance sheet date and are recognized to the extent that it has become more-likely-than-not that the tax benefit will be realized.

As approved by the regulator, the Company's Canadian subsidiaries recover income tax expense in customer rates based on income taxes that are currently payable, except for certain regulatory balances for which deferred income tax expense is recovered from, or refunded to, customers in current rates, as prescribed by the regulator. The Company records regulatory assets and liabilities associated with deferred income tax assets and liabilities that will be included in the rate-setting process.

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.

### Materials and Supplies

Materials and supplies represent consumables, small spare parts and construction materials held for internal construction and maintenance of property, plant and equipment. These assets are carried at average cost less any impairments recorded.

### Property, Plant and Equipment

Property, plant and equipment is recorded at original cost, net of customer contributions, and any accumulated impairment losses. The cost of additions, including betterments and replacement asset components, is included on the Consolidated Balance Sheets as property, plant and equipment.

The original cost of property, plant and equipment includes direct materials, direct labour (including employee benefits), contracted services, attributable capitalized financing costs, asset retirement costs, and direct and indirect overheads that are related to the capital project or program. Indirect overheads include a portion of corporate costs such as finance, treasury, human resources, information technology and executive costs. Overhead costs, including corporate functions and field services costs, are capitalized on a fully allocated basis, consistent with an OEB-approved methodology.

Property, plant and equipment in service consists of transmission, distribution, communication, administration and service assets and land easements. Property, plant and equipment also includes future use assets, such as land, major components and spare parts, and capitalized project development costs associated with deferred capital projects.

### Transmission

Transmission assets include assets used for the transmission of high-voltage electricity, such as transmission lines, support structures, foundations, insulators, connecting hardware and grounding systems, and assets used to step up the voltage of electricity from generating stations for transmission and to step down voltages for distribution, including transformers, circuit breakers and switches.

### Distribution

Distribution assets include assets related to the distribution of low-voltage electricity, including lines, poles, switches, transformers, protective devices and metering systems.

### Communication

Communication assets include fibre optic and microwave radio systems, optical ground wire, towers, telephone equipment and associated buildings.

### Administration and Service

Administration and service assets include administrative buildings, personal computers, transport and work equipment, tools and other minor assets.

### Easements

Easements include statutory rights of use for transmission corridors and abutting lands granted under the *Reliable Energy and Consumer Protection Act, 2002*, as well as other land access rights.

### Intangible Assets

Intangible assets separately acquired or internally developed are measured on initial recognition at cost, which comprises purchased software, direct labour (including employee benefits), consulting, engineering, overheads and attributable capitalized financing charges. Following initial recognition, intangible assets are carried at cost, net of any accumulated amortization and accumulated impairment losses. The Company's intangible assets primarily represent major computer applications.

### Capitalized Financing Costs

Capitalized financing costs represent interest costs attributable to the construction of property, plant and equipment or development of intangible assets. The financing cost of attributable borrowed funds is capitalized as part of the acquisition cost of such assets. The capitalized financing costs are a reduction of financing charges recognized in the Consolidated Statements of Operations and Comprehensive Income. Capitalized financing costs are calculated using the Company's weighted average effective cost of debt.

### Construction and Development in Progress

Construction and development in progress consists of the capitalized cost of constructed assets that are not yet complete and which have not yet been placed in service.

**Depreciation and Amortization**

The cost of property, plant and equipment and intangible assets is depreciated or amortized on a straight-line basis based on the estimated remaining service life of each asset category, except for transport and work equipment, which is depreciated on a declining balance basis.

The Company periodically initiates an external independent review of its property, plant and equipment and intangible asset depreciation and

amortization rates, as required by the OEB. Any changes arising from OEB approval of such a review are implemented on a remaining service life basis, consistent with their inclusion in electricity rates. The most recent reviews resulted in changes to rates effective January 1, 2015 and January 1, 2017 for Hydro One Networks’ distribution and transmission businesses, respectively. A summary of average service lives and depreciation and amortization rates for the various classes of assets is included below:

	Average Service Life	Rate Range	Rate Average
Property, plant and equipment:			
Transmission	55 years	1% – 3%	2%
Distribution	46 years	1% – 7%	2%
Communication	16 years	1% – 15%	6%
Administration and service	20 years	1% – 20%	6%
Intangible assets	10 years	10%	10%

In accordance with group depreciation practices, the original cost of property, plant and equipment, or major components thereof, and intangible assets that are normally retired, is charged to accumulated depreciation, with no gain or loss being reflected in results of operations. Where a disposition of property, plant and equipment occurs through sale, a gain or loss is calculated based on proceeds and such gain or loss is included in depreciation expense.

**Acquisitions and Goodwill**

The Company accounts for business acquisitions using the acquisition method of accounting and, accordingly, the assets and liabilities of the acquired entities are primarily measured at their estimated fair value at the date of acquisition. Costs associated with pending acquisitions are expensed as incurred. Goodwill represents the cost of acquired companies that is in excess of the fair value of the net identifiable assets acquired at the acquisition date. Goodwill is not included in rate base.

Goodwill is evaluated for impairment on an annual basis, or more frequently if circumstances require. The Company performs a qualitative assessment to determine whether it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount. If the Company determines, as a result of its qualitative assessment, that it is not more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, no further testing is required. If the Company determines, as a result of its qualitative assessment, that it is more-likely-than-not that the fair value of the applicable reporting unit is less than its carrying amount, a goodwill impairment assessment is performed using a two-step, fair value-based test. The first step compares the fair value of the applicable reporting unit to its carrying amount, including goodwill. If the carrying amount of the applicable reporting unit exceeds its fair value, a second step is performed. The second step requires an allocation of fair value to the individual assets and liabilities using purchase price allocation in order to determine the implied fair value of goodwill. If the implied fair value of goodwill is less than the carrying amount, an impairment loss is recorded as a reduction to goodwill and as a charge to results of operations.

Based on assessment performed as at September 30, 2018, the Company has concluded that goodwill was not impaired at December 31, 2018.

**Long-Lived Asset Impairment**

When circumstances indicate the carrying value of long-lived assets may not be recoverable, the Company evaluates whether the carrying value of such assets, excluding goodwill, has been impaired. For such long-lived assets, the Company evaluates whether impairment may exist by estimating future estimated undiscounted cash flows expected to result from the use and eventual disposition of the asset. When alternative courses of action to recover the carrying amount of a long-lived asset are under consideration, a probability-weighted approach is used to develop estimates of future undiscounted cash flows. If the carrying value of the long-lived asset is not recoverable based on the estimated future undiscounted cash flows, an impairment loss is recorded, measured as the excess of the carrying value of the asset over its fair value. As a result, the asset’s carrying value is adjusted to its estimated fair value.

Within its regulated business, the carrying costs of most of Hydro One’s long-lived assets are included in rate base where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

Hydro One regularly monitors the assets of its unregulated Hydro One Telecom subsidiary for indications of impairment. Management assesses the fair value of such long-lived assets using commonly accepted techniques. Techniques used to determine fair value include, but are not limited to, the use of recent third-party comparable sales for reference and internally developed discounted cash flow analysis. Significant changes in market conditions, changes to the condition of an asset, or a change in management’s intent to utilize the asset are generally viewed by management as triggering events to reassess the cash flows related to these long-lived assets. As at December 31, 2018 and 2017, no asset impairment had been recorded for assets within either the Company’s regulated or unregulated businesses.

### Costs of Arranging Debt Financing

For financial liabilities classified as other than held-for-trading and for convertible debentures, the Company defers the external transaction costs related to obtaining financing and presents such amounts net of related debt or convertible debentures on the Consolidated Balance Sheets. Deferred issuance costs are amortized over the contractual life of the related debt or convertible debentures on an effective-interest basis and the amortization is included within financing charges in the Consolidated Statements of Operations and Comprehensive Income. Transaction costs for items classified as held-for-trading are expensed immediately.

### Comprehensive Income

Comprehensive income is comprised of net income and OCI. Hydro One presents net income and OCI in a single continuous Consolidated Statement of Operations and Comprehensive Income.

### Financial Assets and Liabilities

All financial assets and liabilities are classified into one of the following five categories: held-to-maturity; loans and receivables; held-for-trading; other liabilities; or available-for-sale. Financial assets and liabilities classified as held-for-trading are measured at fair value. All other financial assets and liabilities are measured at amortized cost, except accounts receivable and amounts due from related parties, which are measured at the lower of cost or fair value. Accounts receivable and amounts due from related parties are classified as loans and receivables. The Company considers the carrying amounts of accounts receivable and amounts due from related parties to be reasonable estimates of fair value because of the short time to maturity of these instruments. Provisions for impaired accounts receivable are recognized as adjustments to the allowance for doubtful accounts and are recognized when there is objective evidence that the Company will not be able to collect amounts according to the original terms. All financial instrument transactions are recorded at trade date.

Derivative instruments are measured at fair value. Gains and losses from fair valuation are included within financing charges in the period in which they arise. The Company determines the classification of its financial assets and liabilities at the date of initial recognition. The Company designates certain of its financial assets and liabilities to be held at fair value, when it is consistent with the Company's risk management policy disclosed in Note 17 – Fair Value of Financial Instruments and Risk Management.

### Derivative Instruments and Hedge Accounting

The Company closely monitors the risks associated with changes in interest rates on its operations and, where appropriate, uses various instruments to hedge these risks. Certain of these derivative instruments qualify for hedge accounting and are designated as accounting hedges, while others either do not qualify as hedges or have not been designated as hedges (hereinafter referred to as undesignated contracts) as they are part of economic hedging relationships.

The accounting guidance for derivative instruments requires the recognition of all derivative instruments not identified as meeting the normal purchase and sale exemption as either assets or liabilities recorded at fair value on the Consolidated Balance Sheets. For derivative instruments that qualify for hedge accounting, the Company may elect to designate such derivative instruments as either cash flow hedges or fair value hedges. The Company offsets fair value amounts recognized on its Consolidated Balance Sheets related to derivative instruments executed with the same counterparty under the same master netting agreement.

For derivative instruments that qualify for hedge accounting and which are designated as cash flow hedges, the effective portion of any gain or loss, net of tax, is reported as a component of accumulated OCI (AOCI) and is reclassified to results of operations in the same period or periods during which the hedged transaction affects results of operations. Any gains or losses on the derivative instrument that represent either hedge ineffectiveness or hedge components excluded from the assessment of effectiveness are recognized in results of operations. For fair value hedges, changes in fair value of both the derivative instrument and the underlying hedged exposure are recognized in the Consolidated Statements of Operations and Comprehensive Income in the current period. The gain or loss on the derivative instrument is included in the same line item as the offsetting gain or loss on the hedged item in the Consolidated Statements of Operations and Comprehensive Income. The changes in fair value of the undesignated derivative instruments are reflected in results of operations.

Embedded derivative instruments are separated from their host contracts and are carried at fair value on the Consolidated Balance Sheets when: (a) the economic characteristics and risks of the embedded derivative are not clearly and closely related to the economic characteristics and risks of the host contract; (b) the hybrid instrument is not measured at fair value, with changes in fair value recognized in results of operations each period; and (c) the embedded derivative itself meets the definition of a derivative. The Company does not engage in derivative trading or speculative activities and had no embedded derivatives that required bifurcation at December 31, 2018 or 2017.

Hydro One periodically develops hedging strategies taking into account risk management objectives. At the inception of a hedging relationship where the Company has elected to apply hedge accounting, Hydro One formally documents the relationship between the hedged item and the hedging instrument, the related risk management objective, the nature of the specific risk exposure being hedged, and the method for assessing the effectiveness of the hedging relationship. The Company also assesses, both at the inception of the hedge and on a quarterly basis, whether the hedging instruments are effective in offsetting changes in fair values or cash flows of the hedged items.

### Employee Future Benefits

Employee future benefits provided by Hydro One include pension, post-retirement and post-employment benefits. The costs of the Company's pension, post-retirement and post-employment benefit plans are recorded over the periods during which employees render service.

The Company recognizes the funded status of its defined benefit pension, post-retirement and post-employment plans on its Consolidated Balance Sheets and subsequently recognizes the changes in funded status at the end of each reporting year. Defined benefit pension, post-retirement and post-employment plans are considered to be underfunded when the projected benefit obligation (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 as well as corporate and government debt securities, are fair valued at the end of each year. Hydro One records a regulatory asset equal to the net underfunded PBO for its pension plan. Defined benefit pension costs are attributed to labour costs and a portion directly related to acquisition and development of capital assets not exceeding the service cost component of accrual basis defined benefit pension costs 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.

### 3. NEW ACCOUNTING PRONOUNCEMENTS

The following tables present Accounting Standards Updates (ASUs) issued by the Financial Accounting Standards Board that are applicable to Hydro One:

#### Recently Adopted Accounting Guidance

Guidance	Date issued	Description	Effective date	Impact on Hydro One
ASC 606	May 2014 – November 2017	ASC 606 <i>Revenue from Contracts with Customers</i> replaced ASC 605 <i>Revenue Recognition</i> . ASC 606 provides guidance on revenue recognition relating to the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods and services.	January 1, 2018	On January 1, 2018, Hydro One adopted ASC 606 using the retrospective method, without the election of any practical expedients. Upon adoption, there was no material impact to the Company's revenue recognition policy and no adjustments were made to prior period reported financial statements amounts. The Company has included the disclosure requirements of ASC 606 for annual and interim periods in the year of adoption.
ASU 2017-07	March 2017	Service cost components of net benefit cost associated with defined benefit plans are required to be reported in the same line as other compensation costs arising from services rendered by the Company's employees. All other components of net benefit cost are to be presented in the income statement separately from the service cost component. Only the service cost component is eligible for capitalization where applicable.	January 1, 2018	Hydro One applied for a regulatory asset to maintain the capitalization of post-employment benefit related costs and as such, there is no material impact upon adoption. See Note 2 – Significant Accounting Policies and Note 12 – Regulatory Assets and Liabilities.

#### Recently Issued Accounting Guidance Not Yet Adopted

Guidance	Date issued	Description	Effective date	Impact on Hydro One
2016-02 2018-01 2018-10 2018-11 2018-20	February 2016 – December 2018	Lessees are required to recognize the rights and obligations resulting from operating leases as assets (right to use the underlying asset for the term of the lease) and liabilities (obligation to make future lease payments) on the balance sheet. ASU 2018-01 permits an entity to elect an optional practical expedient to not evaluate under ASC 842 land easements that exist or expired before the entity's adoption of ASC 842 and that were not previously accounted for as leases under ASC 840. ASU 2018-10 amends narrow aspects of ASC 842. ASU 2018-11 provides entities with an additional and option transition method in adopting ASC 842. ASU 2018-11 also permits lessors to elect an optional practical expedient to not separate non-lease components from the associated lease component by underlying asset classes. ASU 2018-20 provides relief to lessors that have lease contracts that either require lessees to pay lessor costs directly to a third party or require lessees to reimburse lessors for costs paid by lessors directly to third parties.	January 1, 2019	Hydro One reviewed its existing leases and other contracts that are within the scope of ASC 842. Apart from the existing leases, no other contracts contained lease arrangements. Upon adoption in the first quarter of 2019, the Company will utilize the modified retrospective transition approach using the effective date of January 1, 2019 as its date of initial application. As a result, comparatives will not be updated. The Company will elect the package of practical expedients and the land easement practical expedient upon adoption. The impact to Hydro One's financial statements will be the recognition of approximately \$27 million Right-of-Use (ROU) assets and corresponding lease obligations on the Consolidated Balance Sheet. The ROU assets and lease obligations represent the present value of the Company's remaining minimum lease payments for leases with terms greater than 12 months. Discount rates used in calculating the ROU assets and lease obligations correspond to the Company's incremental borrowing rate.

## Notes to Amended Consolidated Financial Statements

Guidance	Date issued	Description	Effective date	Impact on Hydro One
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
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	Under assessment
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
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, 2020	Under assessment

## 4. BUSINESS COMBINATION

### Avista Corporation Purchase Agreement

In July 2017, Hydro One reached an agreement to acquire Avista Corporation (Merger) for approximately \$6.7 billion in an all-cash transaction. Avista Corporation is an investor-owned utility providing electric generation, transmission, and distribution services. It is headquartered in Spokane, Washington, with service areas in Washington, Idaho, Oregon, Montana and Alaska. The closing of the Merger was subject to receipt of certain regulatory and government approvals, and the satisfaction of customary closing conditions.

The costs related to the acquisition totalling \$69 million (2017 – \$42 million) have been expensed through the consolidated statements of operations. These costs, net of unrealized gains on the foreign exchange contract of \$25 million in the year ended December 31, 2018 and a loss of \$3 million in the year ended December 31, 2017, resulted in net costs of \$44 million and \$45 million, respectively being included in earnings.

On December 5, 2018, the Washington Utilities and Transportation Commission (Washington UTC) issued an order denying the Merger. On December 17, 2018, Hydro One filed a petition requesting the Washington UTC to reconsider its December 5, 2018 order denying the Merger. On January 3, 2019, the Idaho Public Utilities Commission denied Hydro One's application to acquire Avista Corporation. On January 8, 2019, the Washington UTC issued a notice of denial of Hydro One's petition for reconsideration of Washington UTC's December 5, 2018 order denying the Merger. On January 14, 2019, the Oregon Public Utility Commission issued a notice of abeyance until Hydro One and Avista Corporation have sought a reversal of the two denial decisions.

On January 23, 2019, Hydro One and Avista Corporation announced that the companies have mutually agreed to terminate the Merger agreement. As a result of the termination of the Merger agreement, on January 24, 2019, Hydro One paid a US\$103 million termination fee to Avista Corporation as required by the Merger agreement. On January 24, 2019, the Company cancelled the \$1.0 billion non-revolving equity bridge credit facility and on January 25, 2019, Hydro One terminated the US\$2.6 billion non-revolving debt bridge credit facility (Acquisition Credit Facilities). No amounts have been drawn on the Acquisition Credit Facilities. On February 1, 2019, Hydro One entered into a credit agreement for a \$170 million unsecured demand operating credit facility (Demand Facility) for the purpose of funding the payment of the termination fee and other Merger related costs. On February 8, 2019, Hydro One redeemed the convertible debentures and paid the holders of the Instalment Receipts \$513 million (\$333 per \$1,000

principal amount) plus accrued and unpaid interest of \$7 million. The redemption of the convertible debentures was paid with cash on hand. As a result of the termination of the Merger agreement, no payment is due or receivable by Hydro One on the foreign exchange contract.

The following amounts related to the termination of the Merger agreement will be recorded by the Company in its 2019 first quarter financial statements:

- \$138 million OM&A costs for payment of the US\$103 million termination fee;
- \$22 million financing charges, due to revaluation of the foreign-exchange contract to \$nil and reversal of previously recorded gains;
- repayment of \$513 million convertible debentures and related interest of \$7 million; and
- \$24 million financing charges, due to derecognition of the deferred financing costs related to convertible debentures.

See Note 16 – Convertible Debentures and Note 17 – Fair Value of Financial Instruments and Risk Management for details of the convertible debentures and the foreign exchange contract, respectively.

### Orillia Power Purchase Agreement

In August 2016, the Company reached an agreement to acquire Orillia Power Distribution Corporation (Orillia Power), an electricity distribution company located in Simcoe County, Ontario, from the City of Orillia for approximately \$41 million, including the assumption of approximately \$15 million in outstanding indebtedness and regulatory liabilities, subject to closing adjustments and regulatory approval by the OEB. In September 2016, Hydro One filed an application with the OEB to acquire Orillia Power, which was denied by the OEB on April 12, 2018. On September 26, 2018, Hydro One filed a new application with the OEB for approval to acquire Orillia Power.

### Peterborough Distribution Purchase Agreement

On July 31, 2018, Hydro One reached an agreement to acquire the business and distribution assets of Peterborough Distribution Inc. (Peterborough Distribution), an electricity distribution company located in east central Ontario, from the City of Peterborough for approximately \$105 million. The acquisition is conditional upon the satisfaction of customary closing conditions and approval by the OEB and the Competition Bureau. On October 12, 2018, the Company filed an application with the OEB for approval of the acquisition. On November 14, 2018, the Competition Bureau issued no action letter, meaning that transaction can proceed from the Competition Bureau's position.

## 5. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 (millions of dollars)	2018	2017
Depreciation of property, plant and equipment	654	641
Amortization of intangible assets	71	62
Amortization of regulatory assets	22	24
Depreciation and amortization	747	727
Asset removal costs	90	90
	837	817

## Notes to Amended Consolidated Financial Statements

### 6. FINANCING CHARGES

Year ended December 31 (millions of dollars)	2018	2017
Interest on long-term debt	447	450
Interest on convertible debentures	62	24
Interest on short-term notes	14	6
Unrealized loss (gain) on foreign exchange contract (Note 17)	(25)	3
Other	21	14
Less: Interest capitalized on construction and development in progress	(53)	(56)
Interest earned on cash and cash equivalents	(7)	(2)
	459	439

### 7. INCOME TAXES

As a rate regulated utility company, the Company's 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)	2018	2017
Income before income taxes	850	793
Income taxes at statutory rate of 26.5% (2017 – 26.5%)	225	210
Increase (decrease) resulting from:		
Net temporary differences recoverable in future rates charged to customers:		
Capital cost allowance in excess of depreciation and amortization	(68)	(55)
Overheads capitalized for accounting but deducted for tax purposes	(20)	(17)
Interest capitalized for accounting but deducted for tax purposes	(14)	(15)
Pension contributions in excess of pension expense	(11)	(13)
Environmental expenditures	(6)	(6)
Other	(9)	3
Net temporary differences	(128)	(103)
Net permanent differences	1	4
Write-off of unregulated deferred income tax asset (Notes 12, 32)	885	—
Non-recurring tax recovery relating to deferred tax asset sharing <sup>1</sup> (Notes 12, 32)	(68)	—
Total income taxes	915	111
Effective income tax rate	107.6%	14.0%

1 This represents the reversal of cumulative deferred tax expenses recorded in 2017 and 2018 relating to temporary differences that are now being allocated to ratepayers. For rate-setting purposes, the deferred income tax expenses or recovery relating to temporary differences that will be included in the rate-setting process are recorded as regulatory assets and liabilities on the balance sheet.

The major components of income tax expense are as follows:

Year ended December 31 (millions of dollars)	2018	2017
Current income taxes	25	26
Deferred income taxes	890	85
Total income taxes	915	111

## Notes to Amended Consolidated Financial Statements

### Deferred Income Tax Assets and Liabilities

Deferred income tax assets and liabilities expected to be included in the rate-setting process are offset by regulatory assets and liabilities to reflect the anticipated recovery or disposition of these balances within future electricity rates. Deferred income tax assets and liabilities arise from differences between the tax basis and the carrying amounts of the assets and liabilities. At December 31, 2018 and 2017, deferred income tax assets and liabilities consisted of the following:

December 31 (millions of dollars)	2018	2017
<b>Deferred income tax assets</b>		
Post-retirement and post-employment benefits expense in excess of cash payments	526	561
Non-capital losses	302	255
Non-depreciable capital property	271	271
Pension obligations	197	354
Investment in subsidiaries	86	84
Tax credit carryforwards	71	49
Environmental expenditures	59	71
Depreciation and amortization in excess of capital cost allowance	20	125
Other	24	23
	1,556	1,793
Less: valuation allowance	(366)	(364)
Total deferred income tax assets	1,190	1,429
<b>Deferred income tax liabilities</b>		
Capital cost allowance in excess of depreciation and amortization	9	75
Regulatory amounts that are not recognized for tax purposes	188	411
Goodwill	10	10
Other	23	17
Total deferred income tax liabilities	230	513
Net deferred income tax assets	960	916

The net deferred income tax assets are presented on the Consolidated Balance Sheets as follows:

December 31 (millions of dollars)	2018	2017
Long-term:		
Deferred income tax assets	1,018	987
Deferred income tax liabilities	(58)	(71)
Net deferred income tax assets	960	916

The valuation allowance for deferred tax assets as at December 31, 2018 was \$366 million (2017 – \$364 million). The valuation allowance primarily relates to temporary differences for non-depreciable assets and investments in subsidiaries. As of December 31, 2018 and 2017, 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)	2018	2017
2034	2	2
2035	221	222
2036	551	560
2037	172	175
2038	192	—
Total losses	1,138	959

## Notes to Amended Consolidated Financial Statements

### 8. ACCOUNTS RECEIVABLE

December 31 (millions of dollars)	2018	2017
Accounts receivable – billed	292	298
Accounts receivable – unbilled	357	367
Accounts receivable, gross	649	665
Allowance for doubtful accounts	(21)	(29)
Accounts receivable, net	628	636

The following table shows the movements in the allowance for doubtful accounts for the years ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)	2018	2017
Allowance for doubtful accounts – beginning	(29)	(35)
Write-offs	25	25
Additions to allowance for doubtful accounts	(17)	(19)
Allowance for doubtful accounts – ending	(21)	(29)

### 9. OTHER CURRENT ASSETS

December 31 (millions of dollars)	2018	2017
Regulatory assets (Note 12)	42	46
Prepaid expenses and other assets	41	41
Derivative instrument – foreign exchange contract (Note 17)	22	—
Materials and supplies	20	18
	125	105

### 10. PROPERTY, PLANT AND EQUIPMENT

December 31, 2018 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	16,559	5,449	766	11,876
Distribution	10,580	3,561	75	7,094
Communication	1,306	922	48	432
Administration and service	1,548	893	58	713
Easements	647	75	—	572
	30,640	10,900	947	20,687

December 31, 2017 (millions of dollars)	Property, Plant and Equipment	Accumulated Depreciation	Construction in Progress	Total
Transmission	15,509	5,162	989	11,336
Distribution	10,213	3,513	149	6,849
Communication	1,266	853	31	444
Administration and service	1,561	857	46	750
Easements	638	70	—	568
	29,187	10,455	1,215	19,947

Financing charges capitalized on property, plant and equipment under construction were \$51 million in 2018 (2017 – \$54 million).

## Notes to Amended Consolidated Financial Statements

### 11. INTANGIBLE ASSETS

December 31, 2018 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	790	440	60	410
Other	5	5	—	—
	795	445	60	410

December 31, 2017 (millions of dollars)	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	698	370	41	369
Other	5	5	—	—
	703	375	41	369

Financing charges capitalized to intangible assets under development were \$2 million in 2018 (2017 – \$2 million). The estimated annual amortization expense for intangible assets is as follows: 2019 – \$67 million; 2020 – \$50 million; 2021 – \$48 million; 2022 – \$46 million; and 2023 – \$35 million.

### 12. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One has recorded the following regulatory assets and liabilities:

December 31 (millions of dollars)	2018	2017
<b>Regulatory assets:</b>		
Deferred income tax regulatory asset	908	1,762
Pension benefit regulatory asset	547	981
Environmental	165	196
Foregone revenue deferral	—	23
Stock-based compensation	43	40
Post-retirement and post-employment benefits non-service cost	39	—
Debt premium	22	27
Distribution system code exemption	10	10
B2M LP start-up costs	2	4
Post-retirement and post-employment benefits	—	36
Other	27	16
Total regulatory assets	1,763	3,095
Less: current portion	(42)	(46)
	1,721	3,049
<b>Regulatory liabilities:</b>		
Post-retirement and post-employment benefits	130	—
Pension cost differential	55	23
Green Energy expenditure variance	52	60
Retail settlement variance account	39	—
External revenue variance	26	46
2015-2017 rate rider	6	6
Deferred income tax regulatory liability	86	5
Conservation and Demand Management (CDM) deferral variance	—	28
Other	23	17
Total regulatory liabilities	417	185
Less: current portion	(91)	(57)
	326	128

### Deferred Income Tax Regulatory Asset and Liability

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The 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 2018 income tax expense would have been lower by approximately \$686 million (2017 – higher by \$113 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* (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 result in an impairment of a portion of Hydro One Networks' transmission deferred income tax regulatory asset. If the OEB were to apply the same calculation for sharing in Hydro One Networks' 2018-2022 distribution rates, it would also result in an additional impairment of a portion of Hydro One Networks' 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 Divisional Court of Ontario (Appeal). In both cases, the Company's position is that the OEB made errors of fact and law in its determination of allocation of the tax savings between the shareholders and ratepayers. 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 Decision relating to the deferred tax asset to an OEB panel for reconsideration.

Subsequent to year end, 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 of this subsequent event that requires adjustment in the 2018 financial statements, the Company has recognized an impairment charge of Hydro One Networks' distribution deferred income tax regulatory asset of \$474 million and Hydro One Networks' transmission deferred income tax regulatory asset of \$558 million, an increase in deferred income tax regulatory liability of \$81 million, and a decrease in the foregone revenue deferral regulatory asset of \$68 million. After recognition of the related \$314 million deferred tax asset, the Company has recorded an \$867 million one-time decrease in net income as a reversal of revenues of \$68 million, and charge to deferred tax expense of \$799 million. Notwithstanding the recognition of the effects of the decision in the financial statements, the Company is currently considering its options under the Appeal.

### 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, OCI would have been higher by \$435 million (2017 – lower by \$80 million) and OM&A expenses would have been higher by \$1 million (2017 – \$1 million).

### 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 2018, the environmental regulatory asset decreased by \$15 million (2017 – increased by \$8 million) to reflect related changes in the Company's 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 xi and the timing of recovery of all of Hydro One's actual environmental expenditures. In the absence of rate-regulated accounting, 2018 OM&A expenses would have been lower by \$15 million (2017 – higher by \$8 million). In addition, 2018 amortization expense would have been lower by \$22 million (2017 – \$24 million), and 2018 financing charges would have been higher by \$6 million (2017 – \$8 million).

### Foregone Revenue Deferral

As part of its September 2017 decision on Hydro One Networks' transmission rate application for 2017 and 2018 rates, the OEB approved the foregone revenue account to record the difference between revenue earned under the rates approved as part of the decision, effective January 1, 2017, and revenue earned under the interim rates until the approved 2017 rates were implemented. The OEB approved a similar account for B2M LP in June 2017 to record the difference between revenue earned under the newly approved rates, effective January 1, 2017, and the revenue recorded under the interim 2017 rates. The balances of these accounts were returned to or recovered from ratepayers, respectively, over a one-year period ending December 31, 2018. As part of its May 2018 decision, the OEB also directed B2M LP to record in this account any revenue collected in 2018 in excess of the final approved 2018 B2M LP revenue requirement.

### 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, 2018 OM&A expenses would have been higher by \$1 million (2017 – \$8 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.

### Post-Retirement and Post-Employment Benefits

The Company recognizes the net unfunded status of post-retirement and post-employment obligations on the Consolidated Balance Sheets with an incremental offset to the associated regulatory assets. A regulatory asset is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to 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 liability, to the extent of the remeasurement adjustment. In the absence of rate-regulated accounting, 2018 OCI would have been higher by \$166 million (2017 – \$207 million).

### Post-Retirement and Post-Employment Benefits – Non-Service Cost

Hydro One applied to the OEB for a regulatory asset 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 for Hydro One Networks' Transmission Business. It is expected that the regulatory asset application for Hydro One Networks' Distribution business will be considered as part of Hydro One Networks' application for 2018-2022 distribution rates, OEB approval of which is currently pending. Hydro One 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.

### 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.

### 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. There were no additions to this regulatory account in 2018 or 2017. The remaining balance in this account at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

### B2M LP Start-up Costs

In December 2015, OEB issued its decision on B2M LP's application for 2015-2019 and as part of the decision approved the recovery of \$8 million of start-up costs relating to B2M LP. The costs are being recovered over a four-year period which began in 2016, in accordance with the OEB decision.

### Pension Cost Differential

A pension cost differential account was established for Hydro One Networks' transmission and distribution businesses to track the difference between the actual pension expenses incurred and estimated pension costs approved by the OEB. In September 2017, the OEB approved the disposition of the transmission business portion of the total pension cost differential account as at December 31, 2015, including accrued interest, which was recovered over a two-year period ended December 31, 2018. The distribution business portion of the balance as at December 31, 2016, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application. In the absence of rate-regulated accounting, 2018 revenue would have been higher by \$29 million (2017 – \$24 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.

### 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 balance as at December 31, 2014, including accrued interest, was requested for recovery through the 2018-2022 distribution rate application.

### External Revenue Variance

In May 2009, the OEB approved forecasted amounts related to export service revenue, external revenue from secondary land use, and external revenue from station maintenance and engineering and construction work. In November 2012, the OEB again approved forecasted amounts related to these revenue categories and extended the scope to encompass all other external revenues. 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 external revenue variance account balance reflects the excess of actual external revenues compared to the OEB-approved forecasted amounts.

### 2015-2017 Rate Rider

In March 2015, as part of its decision on Hydro One Networks' distribution rate application for 2015-2019, the OEB approved the disposition of certain deferral and variance accounts, including RSVAs and accrued interest. The 2015-2017 Rate Rider account included the balances approved for disposition by the OEB and was disposed of in accordance with the OEB decision over a 32-month period ended December 31, 2017. The balance remaining in the account represents an over-collection to be returned to ratepayers in a future rate application and has not been requested in the current distribution rate application.

## Notes to Amended Consolidated Financial Statements

### CDM Deferral Variance Account

As part of Hydro One Networks' application for 2013 and 2014 transmission rates, Hydro One agreed to establish a new regulatory deferral variance account to track the impact of actual CDM and demand response results on the load forecast compared to the estimated load forecast included in the revenue requirement. The balance in the CDM deferral variance account

related to the actual 2013 and 2014 CDM and demand response results on load forecasts, which are inputs in the UTR, compared to the amounts included in 2013 and 2014 revenue requirements, respectively. The balance of the account at December 31, 2015, including interest, was approved for disposition in the 2017-2018 transmission rate decision and returned to customers over a 2-year period ended December 31, 2018.

### 13. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

December 31 (millions of dollars)	2018	2017
Accounts payable	179	177
Accrued liabilities	590	572
Accrued interest	96	99
Regulatory liabilities (Note 12)	91	57
	<b>956</b>	<b>905</b>

### 14. OTHER LONG-TERM LIABILITIES

December 31 (millions of dollars)	2018	2017
Post-retirement and post-employment benefit liability (Note 19)	1,417	1,519
Pension benefit liability (Note 19)	547	981
Environmental liabilities (Note 20)	139	168
Long-term accounts payable	12	13
Asset retirement obligations (Note 21)	10	9
Other liabilities	10	17
	<b>2,135</b>	<b>2,707</b>

### 15. DEBT AND CREDIT AGREEMENTS

#### Short-Term Notes and Credit Facilities

Hydro One meets its short-term liquidity requirements in part through the issuance of commercial paper under Hydro One Inc.'s Commercial Paper Program which has a maximum authorized amount of \$1.5 billion. These short-term notes are denominated in Canadian dollars with varying maturities up to 365 days. The Commercial Paper Program is supported by Hydro One Inc.'s committed revolving credit facilities totalling \$2.3 billion.

At December 31, 2018, Hydro One's consolidated committed, unsecured and undrawn credit facilities (Operating Credit Facilities) totalling \$2,550 million consisted of the following:

(millions of dollars)	Maturity	Total Amount	Amount Drawn
<b>Hydro One Inc.</b>			
Revolving standby credit facility	June 2022	2,300	—
<b>Hydro One</b>			
Five-year senior, revolving term credit facility	November 2021	250	—
<b>Total</b>		<b>2,550</b>	<b>—</b>

The Company may use the credit facilities for working capital and general corporate purposes. If used, interest on the credit facilities would apply based on Canadian benchmark rates. The obligation of each lender to make any credit extension under its credit facility is subject to various conditions including that no event of default has occurred or would result from such credit extension.

#### 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, 2018, no debt securities have been issued by HOHL.

## Notes to Amended Consolidated Financial Statements

### Long-Term Debt

The following table presents long-term debt outstanding at December 31, 2018 and 2017:

December 31 (millions of dollars)	2018	2017
2.78% Series 28 notes due 2018	—	750
Floating-rate Series 31 notes due 2019 <sup>1</sup>	228	228
1.48% Series 37 notes due 2019 <sup>2</sup>	500	500
4.40% Series 20 notes due 2020	300	300
1.62% Series 33 notes due 2020 <sup>2</sup>	350	350
1.84% Series 34 notes due 2021	500	500
2.57% Series 39 notes due 2021 <sup>2</sup>	300	—
3.20% Series 25 notes due 2022	600	600
2.97% Series 40 notes due 2025	350	—
2.77% Series 35 notes due 2026	500	500
7.35% Debentures due 2030	400	400
6.93% Series 2 notes due 2032	500	500
6.35% Series 4 notes due 2034	385	385
5.36% Series 9 notes due 2036	600	600
4.89% Series 12 notes due 2037	400	400
6.03% Series 17 notes due 2039	300	300
5.49% Series 18 notes due 2040	500	500
4.39% Series 23 notes due 2041	300	300
6.59% Series 5 notes due 2043	315	315
4.59% Series 29 notes due 2043	435	435
4.17% Series 32 notes due 2044	350	350
5.00% Series 11 notes due 2046	325	325
3.91% Series 36 notes due 2046	350	350
3.72% Series 38 notes due 2047	450	450
3.63% Series 41 notes due 2049	750	—
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
<b>Hydro One Inc. long-term debt (a)</b>	<b>10,573</b>	<b>9,923</b>
6.6% Senior Secured Bonds due 2023 (Principal amount – \$107 million)	129	136
4.6% Note Payable due 2023 (Principal amount – \$36 million)	39	40
<b>HOSSM long-term debt (b)</b>	<b>168</b>	<b>176</b>
	<b>10,741</b>	<b>10,099</b>
Add: Net unamortized debt premiums	13	14
Add: Unrealized mark-to-market gain <sup>2</sup>	(5)	(9)
Less: Deferred debt issuance costs	(40)	(37)
<b>Total long-term debt</b>	<b>10,709</b>	<b>10,067</b>

1 The interest rates of the floating-rate notes are referenced to the three-month Canadian dollar bankers' acceptance rate, plus a margin.

2 The unrealized mark-to-market net gain relates to \$50 million of the Series 33 notes due 2020, \$500 million Series 37 notes due 2019, and \$300 million Series 39 notes due 2021. The unrealized mark-to-market net gain is offset by a \$5 million (2017 – \$9 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.

## Notes to Amended Consolidated Financial Statements

### (a) Hydro One Inc. long-term debt

At December 31, 2018, long-term debt of \$10,573 million (2017 – \$9,923 million) was outstanding, the majority of which was issued under Hydro One Inc.'s Medium Term Note (MTN) Program. The maximum authorized principal amount of notes issuable under the current MTN Program prospectus filed in March 2018 is \$4.0 billion. At December 31, 2018, \$2.6 billion remained available for issuance until April 2020.

In 2018, Hydro One Inc. issued long-term debt totalling \$1.4 billion (2017 – \$nil) and repaid long-term debt of \$750 million (2017 – \$600 million) under its MTN Program.

### (b) HOSSM long-term debt

At December 31, 2018, long-term debt of \$168 million (2017 – \$176 million), with a principal amount of \$143 million (2017 – \$146 million) was issued by HOSSM. In 2018, no long-term debt was issued (2017 – \$nil), and \$3 million (2017 – \$2 million) of long-term debt was repaid.

The total long-term debt is presented on the consolidated balance sheets as follows:

December 31 (millions of dollars)	2018	2017
Current liabilities:		
Long-term debt payable within one year	731	752
Long-term liabilities:		
Long-term debt	9,978	9,315
<b>Total long-term debt</b>	<b>10,709</b>	<b>10,067</b>

## 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 (%)
2019	731	448	1.9
2020	653	429	2.9
2021	803	411	2.1
2022	603	393	3.2
2023	131	379	6.1
	2,921	2,060	2.6
2024-2028	850	1,806	2.9
2029 and thereafter	6,945	4,315	5.1
	10,716	8,181	4.2

## 16. CONVERTIBLE DEBENTURES

As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), on February 8, 2019, Hydro One redeemed the Convertible Debentures and paid the holders of the instalment receipts \$513 million (\$333 per \$1,000 principal amount) plus accrued and unpaid interest of \$7 million.

The following table presents the change in convertible debentures during the years ended December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)	2018	2017
Carrying value – beginning	487	—
Receipt of Initial Instalment, net of deferred financing costs	—	486
Amortization of deferred financing costs	2	1
Carrying value – ending	489	487
Face value – ending	513	513

On August 9, 2017, in connection with the Merger (see Note 4 – Business Combinations), the Company completed the sale of \$1,540 million aggregate principal amount of 4.00% convertible unsecured subordinated debentures (Convertible Debentures) represented by instalment receipts, which included the exercise in full of the over-allotment option granted to the underwriters to purchase an additional \$140 million aggregate principal amount of the Convertible Debentures (Debenture Offering).

The Convertible Debentures were sold on an instalment basis at a price of \$1,000 per Convertible Debenture, of which \$333 (Initial Instalment) was paid on closing of the Debenture Offering and the remaining \$667 (Final Instalment) was payable on a date (Final Instalment Date) to be fixed by the Company following satisfaction of conditions precedent to the closing of the acquisition of Avista Corporation. The gross proceeds received from the Initial Instalment were \$513 million. The Company incurred financing costs of \$27 million, which were being amortized to financing charges over approximately 10 years, the contractual term of the Convertible Debentures, using the effective interest rate method.

The Convertible Debentures maturity date was September 30, 2027. A coupon rate of 4% was paid on the \$1,540 million aggregate principal amount of the Convertible Debentures, and based on the carrying value of the Initial Instalment, this translated into an effective annual yield of 12%. After the Final Instalment Date, the interest rate would be 0%. The interest expense recorded in 2018 was \$62 million (2017 – \$24 million).

At the option of the holders and provided that payment of the Final Instalment had been made, each Convertible Debenture would be convertible into common shares of the Company at any time on or after the Final Instalment Date, but prior to the earlier of maturity or redemption by the Company, at a conversion price of \$21.40 per common share, being a conversion rate of 46.7290 common shares per \$1,000 principal amount of Convertible Debentures.

The conversion feature met the definition of a Beneficial Conversion Feature (BCF), with an intrinsic value of approximately \$92 million at the date of issuance. Due to the contingency associated with the debentureholders' ability to exercise the conversion, the BCF has not been recognized, and as a result of the subsequent redemption of the Convertible Debentures on February 8, 2019, there will be no recognition.

### Fair Value Measurements of Long-Term Debt

The fair values and carrying values of the Company's long-term debt at December 31, 2018 and 2017 are as follows:

December 31 (millions of dollars)	2018	2018	2017	2017
	Carrying Value	Fair Value	Carrying Value	Fair Value
Long-term debt measured at fair value:				
\$50 million of MTN Series 33 notes	49	49	49	49
\$500 million MTN Series 37 notes	495	495	492	492
\$300 million MTN Series 39 notes	301	301	—	—
Other notes and debentures	9,864	10,820	9,526	11,027
Long-term debt, including current portion	10,709	11,665	10,067	11,568

### 17. FAIR VALUE OF FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

Fair value is considered to be the exchange price in an orderly transaction between market participants to sell an asset or transfer a liability at the measurement date. The fair value definition focuses on an exit price, which is the price that would be received in the sale of an asset or the amount that would be paid to transfer a liability.

Hydro One classifies its fair value measurements based on the following hierarchy, as prescribed by the accounting guidance for fair value, which prioritizes the inputs to valuation techniques used to measure fair value into three levels:

Level 1 inputs are unadjusted quoted prices in active markets for identical assets or liabilities that Hydro One has the ability to access. An active market for the asset or liability is one in which transactions for the asset or liability occur with sufficient frequency and volume to provide ongoing pricing information.

Level 2 inputs are those other than quoted market prices that are observable, either directly or indirectly, for an asset or liability. Level 2 inputs include, but are not limited to, quoted prices for similar assets or liabilities in an active market, quoted prices for identical or similar assets or liabilities in markets that are not active and inputs other than quoted market prices that are observable for the asset or liability, such as interest-rate curves and yield curves observable at commonly quoted intervals, volatilities, credit risk and default rates. A Level 2 measurement cannot have more than an insignificant portion of the valuation based on unobservable inputs.

Level 3 inputs are any fair value measurements that include unobservable inputs for the asset or liability for more than an insignificant portion of the valuation. A Level 3 measurement may be based primarily on Level 2 inputs.

### Non-Derivative Financial Assets and Liabilities

At December 31, 2018 and 2017, 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.

## Notes to Amended Consolidated Financial Statements

### Fair Value Measurements of Derivative Instruments

At December 31, 2018, Hydro One Inc. had interest-rate swaps with a total notional amount of \$850 million (2017 – \$550 million) that were used to convert fixed-rate debt to floating-rate debt. These swaps are classified as fair value hedges. Hydro One Inc.'s fair value hedge exposure was approximately 8% (2017 – 6%) of its total long-term debt. At December 31, 2018, Hydro One Inc. had the following interest-rate swaps designated as fair value hedges:

- a \$50 million fixed-to-floating interest-rate swap agreement to convert \$50 million of the \$350 million MTN Series 33 notes maturing April 30, 2020 into three-month variable rate debt;
- two \$125 million and one \$250 million fixed-to-floating interest-rate swap agreements to convert the \$500 million MTN Series 37 notes maturing November 18, 2019 into three-month variable rate debt; and
- 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.

At December 31, 2018 and 2017, the Company had no interest-rate swaps classified as undesignated contracts.

In October 2017, the Company entered into a deal-contingent foreign exchange forward contract (foreign exchange contract) to convert \$1.4 billion Canadian to US dollars at an initial forward rate of 1.27486 Canadian per 1.00 US dollars, and a range up to 1.28735 Canadian per 1.00 US dollars based on the settlement date. The contract 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 is an economic hedge and does 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 occur. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), no payment is due or payable by Hydro One on the foreign exchange contract.

### Fair Value Hierarchy

The fair value hierarchy of financial assets and liabilities at December 31, 2018 and 2017 is as follows:

December 31, 2018 (millions of dollars)	Carrying Value	Fair Value	Level 1	Level 2	Level 3
<b>Assets:</b>					
Cash and cash equivalents	483	483	483	—	—
Derivative instrument					
Foreign exchange contract	22	22	—	—	22
	505	505	483	—	22
<b>Liabilities:</b>					
Short-term notes payable	1,252	1,252	1,252	—	—
Long-term debt, including current portion	10,709	11,665	—	11,665	—
Convertible debentures	489	491	491	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	5	5	—	5	—
	12,455	13,413	1,743	11,670	—
<b>December 31, 2017 (millions of dollars)</b>					
<b>Assets:</b>					
Cash and cash equivalents	25	25	25	—	—
	25	25	25	—	—
<b>Liabilities:</b>					
Short-term notes payable	926	926	926	—	—
Long-term debt, including current portion	10,067	11,568	—	11,568	—
Convertible debentures	487	574	574	—	—
Derivative instruments					
Fair value hedges – interest-rate swaps	9	9	—	9	—
Foreign exchange contract	3	3	—	—	3
	11,492	13,080	1,500	11,577	3

## Notes to Amended Consolidated Financial Statements

Cash and cash equivalents include cash and short-term investments. The carrying values are representative of fair value because of the short-term nature of these instruments.

The fair value of the hedged portion of the long-term debt is primarily based on the present value of future cash flows using a swap yield curve to determine the assumption for interest rates. The fair value of the unhedged portion of the long-term debt is based on unadjusted period-end market prices for the same or similar debt of the same remaining maturities.

The fair value of the convertible debentures is based on their closing price on December 31, 2018, as posted on the Toronto Stock Exchange.

The Company uses derivative instruments as an economic hedge for foreign exchange risk. The value of the foreign exchange contract is derived using valuation models commonly used for derivatives. These valuation models require a variety of inputs, including contractual terms, forward price yield curves, probability of closing the Merger, and the contract settlement date. The Company's valuation models also reflect measurements for credit risk. The fair value of the foreign exchange contract includes significant unobservable inputs, and therefore has been classified accordingly as Level 3. The significant unobservable inputs used in the fair value measurement of the foreign exchange contract relates to the assessment of probability of closing the Merger and the contract settlement date.

### Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2018 and 2017.

Year ended December 31 (millions of dollars)	2018	2017
Fair value of asset (liability) – beginning	(3)	—
Unrealized gain (loss) on foreign exchange contract included in financing charges	25	(3)
Fair value of asset (liability) – ending	22	(3)

There were no transfers between any of the fair value levels during the years ended December 31, 2018 or 2017.

### Risk Management

Exposure to market risk, credit risk and liquidity risk arises in the normal course of the Company's business.

#### Market Risk

Market risk refers primarily to the risk of loss which results from changes in costs, foreign exchange rates and interest rates. The Company is exposed to fluctuations in interest rates, as its regulated return on equity is derived using a formulaic approach that takes anticipated interest rates into account. The Company is not currently exposed to material commodity price risk.

The Company uses a combination of fixed and variable-rate debt to manage the mix of its debt portfolio. The Company also uses derivative financial instruments to manage interest-rate risk. The Company utilizes interest-rate swaps, which are typically designated as fair value hedges, as a means to manage its interest rate exposure to achieve a lower cost of debt. The Company may also utilize interest-rate derivative instruments to lock in interest-rate levels in anticipation of future financing.

A hypothetical 100 basis points increase in interest rates associated with variable-rate debt would not have resulted in a significant decrease in Hydro One's net income for the years ended December 31, 2018 and 2017.

The Company was exposed to foreign exchange fluctuations as a result of entering into a foreign exchange contract. This agreement was intended to mitigate the foreign currency risk related to the portion of the Avista Corporation acquisition purchase price financed with the issuance of Convertible Debentures. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), no payment is due or receivable by Hydro One on the foreign exchange contract.

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, 2018 and 2017 was not material.

#### Credit Risk

Financial assets create a risk that a counterparty will fail to discharge an obligation, causing a financial loss. At December 31, 2018 and 2017, 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, 2018 and 2017, there was no material accounts receivable balance due from any single customer.

At December 31, 2018, the Company's provision for bad debts was \$21 million (2017 – \$29 million). Adjustments and write-offs are determined on the basis of a review of overdue accounts, taking into consideration historical experience. At December 31, 2018, approximately 5% (2017 – 5%) of the Company's net accounts receivable were outstanding for more than 60 days.

## Notes to Amended Consolidated Financial Statements

Hydro One manages its counterparty credit risk through various techniques including: entering into transactions with highly rated counterparties; limiting total exposure levels with individual counterparties; entering into master agreements which enable net settlement and the contractual right of offset; and monitoring the financial condition of counterparties. The Company monitors current credit exposure to counterparties both on an individual and an aggregate basis. The Company's credit risk for accounts receivable is limited to the carrying amounts on the Consolidated Balance Sheets.

Derivative financial instruments result in exposure to credit risk since there is a risk of counterparty default. The credit exposure of derivative contracts, before collateral, is represented by the fair value of contracts at the reporting date. At December 31, 2018 and 2017, the counterparty credit risk exposure on the fair value of these interest-rate swap contracts was not material. At December 31, 2018, Hydro One's credit exposure for all derivative instruments, and applicable payables and receivables, had a credit rating of investment grade, with four financial institutions as the counterparties.

### Liquidity Risk

Liquidity risk refers to the Company's ability to meet its financial obligations as they come due. Hydro One meets its short-term 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, Operating Credit Facilities, and anticipated levels of funds from operations are expected to be sufficient to fund normal operating requirements.

On June 18, 2018, Hydro One filed a short form base shelf prospectus (Universal Base Shelf Prospectus) with securities regulatory authorities in Canada to replace the universal base shelf prospectus that expired on April 30, 2018. The Universal Base Shelf Prospectus allows Hydro One to offer, from time to time in one or more public offerings, up to \$4.0 billion of debt, equity or other securities, or any combination thereof, during the 25-month period ending on July 18, 2020. On November 23, 2018, 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 for the purposes of, but not limited to, funding a portion of the cash purchase price of the Merger. The US Debt Shelf Prospectus allows HOHL to offer, from time to time in one or more public offerings, up to US\$3.0 billion of debt securities, unconditionally guaranteed by Hydro One, during the 25-month period ending on December 23, 2020. At December 31, 2018, no securities have been issued under the Universal Base Shelf Prospectus or the US Debt Shelf Prospectus.

## 18. CAPITAL MANAGEMENT

The Company's objectives with respect to its capital structure are to maintain effective access to capital on a long-term basis at reasonable rates, and to deliver appropriate financial returns. In order to ensure ongoing access to capital, the Company targets to maintain strong credit quality. At December 31, 2018 and 2017, the Company's capital structure was as follows:

December 31 (millions of dollars)	2018	2017
Long-term debt payable within one year	731	752
Short-term notes payable	1,252	926
Less: cash and cash equivalents	(483)	(25)
	1,500	1,653
Long-term debt	9,978	9,315
Convertible debentures	489	487
Preferred shares	418	418
Common shares	5,643	5,631
Retained earnings	3,459	4,090
<b>Total capital</b>	<b>21,487</b>	<b>21,594</b>

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, 2018, the Company was in compliance with all financial covenants and limitations associated with the outstanding borrowings and credit facilities.

## 19. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS

Hydro One has a defined benefit pension plan (Pension Plan), a 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. Hydro One contributions to the DC Plan for the year ended December 31, 2018 were \$1 million (2017 – \$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. Annual Pension Plan contributions for 2018 were \$75 million (2017 – \$87 million). Estimated annual Pension Plan contributions for the years 2019, 2020, 2021, 2022, 2023 and 2024 are approximately \$78 million, \$77 million, \$78 million, \$79 million, \$81 million and \$83 million, respectively. The most recent actuarial valuation was performed effective December 31, 2017, and the next actuarial valuation will be performed no later than effective December 31, 2020. Contributions are payable one month in arrears. All of the contributions are expected to be in the form of cash.

The Supplemental Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan 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, post-retirement and post-employment benefit obligations is generally recognized over the expected average remaining service period of the employees. The measurement date for the Plans is December 31.

The following tables provide the components of the unfunded status of the Company's Plans at December 31, 2018 and 2017:

Year ended December 31 (millions of dollars)	Pension Benefits		Post-Retirement and Post-Employment Benefits	
	2018	2017	2018	2017
<b>Change in projected benefit obligation</b>				
Projected benefit obligation, beginning of year	8,258	7,774	1,565	1,690
Current service cost	176	147	50	49
Employee contributions	52	49	—	—
Interest cost	282	304	54	67
Benefits paid	(362)	(368)	(49)	(44)
Net actuarial loss (gain)	(654)	352	(158)	(197)
Recognition of prior service	—	—	3	—
Projected benefit obligation, end of year	7,752	8,258	1,465	1,565
<b>Change in plan assets</b>				
Fair value of plan assets, beginning of year	7,277	6,874	—	—
Actual return on plan assets	190	662	—	—
Benefits paid	(362)	(368)	(49)	(34)
Employer contributions	75	87	49	34
Employee contributions	52	49	—	—
Administrative expenses	(27)	(27)	—	—
Fair value of plan assets, end of year	7,205	7,277	—	—
Unfunded status	547	981	1,465	1,565

## Notes to Amended Consolidated Financial Statements

Hydro One presents its benefit obligations and plan assets net on its Consolidated Balance Sheets as follows:

December 31 (millions of dollars)	2018	Pension Benefits 2017	Post-Retirement and Post-Employment Benefits	
			2018	2017
Other assets <sup>1</sup>	3	1	—	—
Accrued liabilities	—	—	55	53
Pension benefit liability	547	981	—	—
Post-retirement and post-employment benefit liability <sup>2</sup>	—	—	1,417	1,519
<b>Net unfunded status</b>	<b>544</b>	<b>980</b>	<b>1,472</b>	<b>1,572</b>

1 Represents the funded status of HOSSM defined benefit pension plan.

2 Includes \$7 million (2017 – \$7 million) relating to HOSSM post-employment benefit plans.

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:

December 31 (millions of dollars)	2018	2017
PBO	7,752	8,258
ABO	7,144	7,614
Fair value of plan assets	7,205	7,277

On an ABO basis, the Pension Plan was funded at 101% at December 31, 2018 (2017 – 96%). On a PBO basis, the Pension Plan was funded at 93% at December 31, 2018 (2017 – 88%). The ABO differs from the PBO in that the ABO includes no assumption about future compensation levels.

### Components of Net Periodic Benefit Costs

The following table provides the components of the net periodic benefit costs for the years ended December 31, 2018 and 2017 for the Pension Plan:

Year ended December 31 (millions of dollars)	2018	2017
Current service cost	176	147
Interest cost	282	304
Expected return on plan assets, net of expenses	(467)	(442)
Amortization of actuarial losses	84	79
<b>Net periodic benefit costs</b>	<b>75</b>	<b>88</b>
<b>Charged to results of operations<sup>1</sup></b>	<b>32</b>	<b>39</b>

1 The Company accounts for pension costs consistent with their inclusion in OEB-approved rates. During the year ended December 31, 2018, pension costs of \$75 million (2017 – \$87 million) were attributed to labour, of which \$32 million (2017 – \$39 million) was charged to operations, and \$43 million (2017 – \$48 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, 2018 and 2017 for the post-retirement and post-employment benefit plans:

Year ended December 31 (millions of dollars)	2018	2017
Current service cost	50	49
Interest cost	53	67
Amortization of actuarial losses	15	16
Recognition of prior service	3	—
<b>Net periodic benefit costs</b>	<b>121</b>	<b>132</b>
<b>Charged to results of operations</b>	<b>52</b>	<b>59</b>

## Notes to Amended Consolidated Financial Statements

### 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, 2018 and 2017:

Year ended December 31	Pension Benefits		Post-Retirement and Post-Employment Benefits	
	2018	2017	2018	2017
<b>Significant assumptions:</b>				
Weighted average discount rate	3.90%	3.40%	4.00%	3.40%
Rate of compensation scale escalation (long-term)	2.50%	2.50%	2.50%	2.50%
Rate of cost of living increase	2.00%	2.00%	2.00%	2.00%
Rate of increase in health care cost trends <sup>1</sup>	—	—	4.04%	4.04%

<sup>1</sup> 5.19% per annum in 2019, grading down to 4.04% per annum in and after 2031 (2017 – 5.26% per annum in 2018, 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, 2018 and 2017.

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	2018	2017
<b>Pension Benefits:</b>		
Weighted average expected rate of return on plan assets	6.50%	6.50%
Weighted average discount rate	3.40%	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
<b>Post-Retirement and Post-Employment Benefits:</b>		
Weighted average discount rate	3.40%	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)	15.5	15.2
Rate of increase in health care cost trends <sup>1</sup>	4.04%	4.36%

<sup>1</sup> 5.26% per annum in 2018, grading down to 4.04% per annum in and after 2031 (2017 – 6.25% per annum in 2017, grading down to 4.36% per annum in and after 2031).

The discount rate used to determine the current year pension obligation and the subsequent year's net periodic benefit costs is based on a yield curve approach. Under the yield curve approach, expected future benefit payments for each plan are discounted by a rate on a third-party bond yield curve corresponding to each duration. The yield curve is based on "AA" long-term corporate bonds. A single discount rate is calculated that would yield the same present value as the sum of the discounted cash flows.

The effect of a 1% change in health care cost trends on the PBO for the post-retirement and post-employment benefits at December 31, 2018 and 2017 is as follows:

December 31 (millions of dollars)	2018	2017
<b>Projected benefit obligation:</b>		
Effect of a 1% increase in health care cost trends	230	250
Effect of a 1% decrease in health care cost trends	(175)	(189)

## Notes to Amended Consolidated Financial Statements

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, 2018 and 2017 is as follows:

Year ended December 31 (millions of dollars)	2018	2017
<b>Service cost and interest cost:</b>		
Effect of a 1% increase in health care cost trends	23	29
Effect of a 1% decrease in health care cost trends	(16)	(20)

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, 2018 and 2017:

December 31, 2018				December 31, 2017			
Life expectancy at 65 for a member currently at		Life expectancy at 65 for a member currently at		Life expectancy at 65 for a member currently at		Life expectancy at 65 for a member currently at	
Age 65	Age 45						
Male	Female	Male	Female	Male	Female	Male	Female
22	25	23	25	22	24	23	24

### Estimated Future Benefit Payments

At December 31, 2018, estimated future benefit payments to the participants of the Plans were:

(millions of dollars)	Pension Benefits	Post-Retirement and Post-Employment Benefits
2019	335	56
2020	343	58
2021	352	59
2022	360	60
2023	367	61
2024 through to 2028	1,915	326
Total estimated future benefit payments through to 2028	3,672	620

### Components of Regulatory Assets

A portion of actuarial gains and losses and prior service costs is recorded within regulatory assets on Hydro One's Consolidated Balance Sheets to reflect the expected regulatory inclusion of these amounts in future rates, which would otherwise be recorded in OCI. The following table provides the actuarial gains and losses and prior service costs recorded within regulatory assets:

Year ended December 31 (millions of dollars)	2018	2017
<b>Pension Benefits:</b>		
Actuarial loss (gain) for the year	(350)	159
Amortization of actuarial losses	(84)	(79)
	(434)	80
<b>Post-Retirement and Post-Employment Benefits:</b>		
Actuarial loss (gain) for the year	(158)	(197)
Amortization of actuarial losses	(15)	(16)
Amortization of prior service cost	(3)	—
Amounts not subject to regulatory treatment	10	6
	(166)	(207)

## Notes to Amended Consolidated Financial Statements

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, 2018 and 2017:

Year ended December 31 (millions of dollars)	2018	2017
<b>Pension Benefits:</b>		
Actuarial loss	547	981
<b>Post-Retirement and Post-Employment Benefits:</b>		
Actuarial loss (gain)	(130)	36

The following table provides the components of regulatory assets at December 31 that are expected to be amortized as components of net periodic benefit costs in the following year:

December 31 (millions of dollars)	Pension Benefits		Post-Retirement and Post-Employment Benefits	
	2018	2017	2018	2017
Actuarial loss (gain)	55	84	(1)	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 due. As part of this ongoing evaluation, Hydro One may make changes to its targeted asset allocation and investment strategy. The Pension Plan is managed at a net asset level. The main objective of the Pension Plan is to sustain a certain level of net assets in order to meet the pension obligations of the Company. The Pension Plan fulfills its primary objective by adhering to specific investment policies outlined in its Summary of Investment Policies

and Procedures (SIPP), which is reviewed and approved by the Human Resource Committee of Hydro One's Board of Directors. The Company manages net assets by engaging knowledgeable external investment managers who are charged with the responsibility of investing existing funds and new funds (current year's employee and employer contributions) in accordance with the approved SIPP. The performance of the managers is monitored through a governance structure. Increases in net assets are a direct result of investment income generated by investments held by the Pension Plan and contributions to the Pension Plan by eligible employees and by the Company. The main use of net assets is for benefit payments to eligible Pension Plan members.

#### Pension Plan Asset Mix

At December 31, 2018, the Pension Plan target asset allocations and weighted average asset allocations were as follows:

	Target Allocation (%)	Pension Plan Assets (%)
Equity securities	45	50
Debt securities	35	41
Other <sup>1</sup>	20	9
	100	100

<sup>1</sup> Other investments include real estate and infrastructure investments.

At December 31, 2018, the Pension Plan held \$18 million (2017 – \$11 million) Hydro One corporate bonds and \$546 million (2017 – \$415 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, 2018 and 2017. 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, 2018 and 2017, 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.

## Notes to Amended Consolidated Financial Statements

### 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, 2018 and 2017:

December 31, 2018 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	—	21	651	672
Cash and cash equivalents	210	—	—	210
Short-term securities	—	78	—	78
Derivative instruments	—	(7)	—	(7)
Corporate shares – Canadian	115	—	—	115
Corporate shares – Foreign	3,222	183	—	3,405
Bonds and debentures – Canadian	—	2,506	—	2,506
Bonds and debentures – Foreign	—	197	—	197
<b>Total fair value of plan assets<sup>1</sup></b>	<b>3,547</b>	<b>2,978</b>	<b>651</b>	<b>7,176</b>

<sup>1</sup> At December 31, 2018, the total fair value of Pension Plan assets and liabilities excludes \$35 million of interest and dividends receivable, \$10 million of pension administration expenses payable, \$6 million of sold investments receivable, and \$2 million of purchased investments payable.

December 31, 2017 (millions of dollars)	Level 1	Level 2	Level 3	Total
Pooled funds	—	16	549	565
Cash and cash equivalents	153	—	—	153
Short-term securities	—	109	—	109
Derivative instruments	—	5	—	5
Corporate shares – Canadian	921	—	—	921
Corporate shares – Foreign	3,307	125	—	3,432
Bonds and debentures – Canadian	—	1,879	—	1,879
Bonds and debentures – Foreign	—	194	—	194
<b>Total fair value of plan assets<sup>1</sup></b>	<b>4,381</b>	<b>2,328</b>	<b>549</b>	<b>7,258</b>

<sup>1</sup> At December 31, 2017, the total fair value of Pension Plan assets and liabilities excludes \$28 million of interest and dividends receivable, \$10 million of pension administration expenses payable, \$1 million of sold investments receivable, and \$1 million of purchased investments payable.

See Note 17 – Fair Value of Financial Instruments and Risk Management for a description of levels within the fair value hierarchy.

### Changes in the Fair Value of Financial Instruments Classified in Level 3

The following table summarizes the changes in fair value of financial instruments classified in Level 3 for the years ended December 31, 2018 and 2017. 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)	2018	2017
Fair value, beginning of year	549	425
Realized and unrealized gains (losses)	59	(31)
Purchases	90	171
Sales and disbursements	(47)	(16)
<b>Fair value, end of year</b>	<b>651</b>	<b>549</b>

There were no significant transfers between any of the fair value levels during the years ended December 31, 2018 and 2017.

### Valuation Techniques Used to Determine Fair Value

Pooled funds mainly consist of private equity, real estate and infrastructure investments. Private equity investments represent private equity funds that invest in operating companies that are not publicly traded on a stock exchange. Investment strategies in private equity include limited partnerships in businesses that are characterized by high internal growth and operational

efficiencies, venture capital, leveraged buyouts and special situations such as distressed investments. Real estate and infrastructure investments represent funds that invest in real assets which are not publicly traded on a stock exchange. Investment strategies in real estate include limited partnerships that seek to generate a total return through income and capital growth by investing primarily in global and Canadian limited partnerships. Investment strategies in infrastructure include limited partnerships in core infrastructure assets focusing on assets that generate stable, long-term cash flows and deliver incremental returns relative to conventional fixed-income investments.

## Notes to Amended Consolidated Financial Statements

Private equity, real estate and infrastructure valuations are reported by the fund manager and are based on the valuation of the underlying investments which includes inputs such as cost, operating results, discounted future cash flows and market-based comparable data. Since these valuation inputs are not highly observable, private equity and infrastructure investments have been categorized as Level 3 within pooled funds.

Cash equivalents consist of demand cash deposits held with banks and cash held by the investment managers. Cash equivalents are categorized as Level 1.

Short-term securities are valued at cost plus accrued interest, which approximates fair value due to their short-term nature. Short-term securities are categorized as Level 2.

Derivative instruments are used to hedge the Pension Plan's foreign currency exposure back to Canadian dollars. The notional principal amount of contracts outstanding as at December 31, 2018 was \$299 million

(2017 – \$279 million), the most significant currencies being hedged against the Canadian dollar are the United States dollar, Euro, and Japanese Yen. The net realized loss on contracts for the year ended December 31, 2018 was \$7 million (2017 – \$1 million net realized gain). The terms to maturity of the forward exchange contracts at December 31, 2018 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.

## 20. ENVIRONMENTAL LIABILITIES

The following tables show the movements in environmental liabilities for the years ended December 31, 2018 and 2017:

Year ended December 31, 2018 (millions of dollars)	PCB	LAR	Total
Environmental liabilities – beginning	134	62	196
Interest accretion	5	1	6
Expenditures	(16)	(6)	(22)
Revaluation adjustment	(15)	—	(15)
Environmental liabilities – ending	108	57	165
Less: current portion	(15)	(11)	(26)
	93	46	139

Year ended December 31, 2017 (millions of dollars)	PCB	LAR	Total
Environmental liabilities – beginning	143	61	204
Interest accretion	6	2	8
Expenditures	(16)	(8)	(24)
Revaluation adjustment	1	7	8
Environmental liabilities – ending	134	62	196
Less: current portion	(20)	(8)	(28)
	114	54	168

The following tables show the reconciliation between the undiscounted basis of the environmental liabilities and the amount recognized on the Consolidated Balance Sheets after factoring in the discount rate:

December 31, 2018 (millions of dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	118	58	176
Less: discounting environmental liabilities to present value	(10)	(1)	(11)
Discounted environmental liabilities	108	57	165

December 31, 2017 (millions of dollars)	PCB	LAR	Total
Undiscounted environmental liabilities	142	64	206
Less: discounting environmental liabilities to present value	(8)	(2)	(10)
Discounted environmental liabilities	134	62	196

## Notes to Amended Consolidated Financial Statements

At December 31, 2018, the estimated future environmental expenditures were as follows:

(millions of dollars)

2019	26
2020	29
2021	32
2022	31
2023	28
Thereafter	30
	176

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 in concentrations of less than 2 ppm.

The Company's best estimate of the total estimated future expenditures to comply with current PCB regulations is \$118 million (2017 – \$142 million). These expenditures are expected to be incurred over the period from 2019 to 2024. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2018 to decrease the PCB environmental liability by \$15 million (2017 – increase by \$1 million).

### LAR

The Company's best estimate of the total estimated future expenditures to complete its LAR program is \$58 million (2017 – \$64 million). These expenditures are expected to be incurred over the period from 2019 to 2044. As a result of its annual review of environmental liabilities, no revaluation adjustment to the LAR environmental liability was recorded in 2018 (2017 – revaluation adjustment was recorded to increase the LAR environmental liability by \$7 million).

## 21. ASSET RETIREMENT OBLIGATIONS

Hydro One records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

In determining the amounts to be recorded as asset retirement obligations, the Company estimates the current fair value for completing required work and makes assumptions as to when the future expenditures will actually be incurred, in order to generate future cash flow information. A long-term inflation assumption of approximately 2% has been used to express these current cost estimates as estimated future expenditures. Future expenditures have been discounted using factors ranging from approximately 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

## Notes to Amended Consolidated Financial Statements

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 2018 to increase the asset retirement liability by \$1 million (2017 – \$nil).

At December 31, 2018, Hydro One had recorded asset retirement obligations of \$10 million (2017 – \$9 million), primarily consisting of the estimated future expenditures associated with the removal and disposal of asbestos-containing materials installed in some of its facilities. The amount of interest recorded is nominal.

The following tables present the changes to common shares during the years ended December 31, 2018 and 2017:

Year ended December 31, 2018 (number of shares)	Ownership by		Total
	Public	Province	
Common shares – beginning	312,974,063	282,412,648	595,386,711
Common shares issued – share grants <sup>1</sup>	481,460	—	481,460
Common shares issued – LTIP <sup>2</sup>	70,804	—	70,804
Common shares – ending	313,526,327	282,412,648	595,938,975
	52.6%	47.4%	100%

1 In 2018, Hydro One issued from treasury 481,460 common shares in accordance with provisions of the Power Workers' Union (PWU) and the Society Share Grant Plans.

2 In 2018, Hydro One issued from treasury 70,804 common shares in accordance with provisions of the LTIP.

Year ended December 31, 2017 (number of shares)	Ownership by		Total
	Public	Province	
Common shares – beginning	178,196,340	416,803,660	595,000,000
Secondary offering <sup>1</sup>	120,000,000	(120,000,000)	—
Common shares issued – share grants <sup>2</sup>	371,611	—	371,611
Common shares issued – LTIP <sup>3</sup>	15,100	—	15,100
Sale of common shares <sup>4</sup>	14,391,012	(14,391,012)	—
Common shares – ending	312,974,063	282,412,648	595,386,711
	52.6%	47.4%	100%

1 In May 2017, Hydro One announced the closing of a secondary offering by the Province, on a bought deal basis, of 120 million common shares of Hydro One on the Toronto Stock Exchange. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

2 In 2017, Hydro One issued from treasury 371,611 common shares in accordance with provisions of the PWU Share Grant Plan.

3 In 2017, Hydro One issued from treasury 15,100 common shares in accordance with provisions of the LTIP.

4 In December 2017, the Province sold 14,391,012 common shares of Hydro One to OFN Power Holdings LP, a limited partnership wholly-owned by Ontario First Nations Sovereign Wealth LP, which is in turn owned by 129 First Nations in Ontario. Hydro One did not receive any of the proceeds from the sale of the common shares by the Province.

### Preferred Shares

The Company is authorized to issue an unlimited number of preferred shares, issuable in series. At December 31, 2018 and 2017, two series of preferred shares were authorized for issuance: the Series 1 preferred shares and the Series 2 preferred shares. At December 31, 2018 and 2017, the Company had 16,720,000 Series 1 preferred shares and no Series 2 preferred shares issued and outstanding.

Hydro One may from time to time issue preferred shares in one or more series. Prior to issuing shares in a series, the Hydro One Board of Directors is required to fix the number of shares in the series and determine the

## 22. SHARE CAPITAL

### Common Shares

The Company is authorized to issue an unlimited number of common shares. At December 31, 2018, the Company had 595,938,975 (2017 – 595,386,711) 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.

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.

## Notes to Amended Consolidated Financial Statements

For the period commencing from the date of issue of the Series 1 preferred shares and ending on and including November 19, 2020, the holders of Series 1 preferred shares are entitled to receive fixed cumulative preferential dividends of \$1.0625 per share per year, if and when declared by the Board of Directors, payable quarterly. The dividend rate will reset on November 20, 2020 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 3.53%. The Series 1 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One on November 20, 2020 and on November 20 of every fifth year thereafter at a redemption price equal to \$25.00 for each Series 1 preferred share redeemed, plus any accrued or unpaid dividends. The holders of Series 1 preferred shares will have the right, at their option, on November 20, 2020 and on November 20 of every fifth year thereafter, to convert all or any of their Series 1 preferred shares into Series 2 preferred shares on a one-for-one basis, subject to certain restrictions on conversion. At December 31, 2018, no preferred share dividends were in arrears.

The holders of Series 2 preferred shares will be entitled to receive quarterly floating rate cumulative dividends, if and when declared by the Board of Directors, at a rate equal to the sum of the then three-month Government of Canada treasury bill rate and 3.53% as reset quarterly. The Series 2 preferred shares will not be redeemable by Hydro One prior to November 20, 2020, but will be redeemable by Hydro One at a redemption price equal to \$25.00 for each Series 2 preferred share redeemed, if redeemed on November 20, 2025 or on November 20

of every fifth year thereafter, or \$25.50 for each Series 2 preferred share redeemed, if redeemed on any other date after November 20, 2020, in each case plus any accrued or unpaid dividends. The holders of Series 2 preferred shares will have the right, at their option, on November 20, 2025 and on November 20 of every fifth year thereafter, to convert all or any of their Series 2 preferred shares into Series 1 preferred shares on a one-for-one basis, subject to certain restrictions on conversion.

### Share Ownership Restrictions

The *Electricity Act* imposes share ownership restrictions on securities of Hydro One carrying a voting right (Voting Securities). These restrictions provide that no person or company (or combination of persons or companies acting jointly or in concert) may beneficially own or exercise control or direction over more than 10% of any class or series of Voting Securities, including common shares of the Company (Share Ownership Restrictions). The Share Ownership Restrictions do not apply to Voting Securities held by the Province, nor to an underwriter who holds Voting Securities solely for the purpose of distributing those securities to purchasers who comply with the Share Ownership Restrictions.

## 23. DIVIDENDS

In 2018, preferred share dividends in the amount of \$18 million (2017 – \$18 million) and common share dividends in the amount of \$542 million (2017 – \$518 million) were declared.

## 24. EARNINGS PER COMMON SHARE

Basic earnings per common share (EPS) is calculated by dividing net income (loss) attributable to common shareholders of Hydro One by the weighted-average number of common shares outstanding.

Diluted EPS is calculated by dividing net income (loss) 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	2018	2017
Net income (loss) attributable to common shareholders (millions of dollars)	(89)	658
Weighted average number of shares		
Basic	595,756,470	595,287,586
Effect of dilutive stock-based compensation plans	2,147,473	2,234,665
Diluted	597,903,943	597,522,251
EPS		
Basic	\$ (0.15)	\$ 1.11
Diluted	\$ (0.15)	\$ 1.10

The common shares contingently issuable as a result of the Convertible Debentures are not included in diluted EPS as conditions for closing the Merger were not met as at December 31, 2018. As a result of the termination of the Merger agreement (see Note 4 – Business Combinations), the Convertible Debentures were redeemed on February 8, 2019.

## 25. STOCK-BASED COMPENSATION

### Share Grant Plans

Hydro One has two share grant plans (Share Grant Plans), one for the benefit of certain members of the PWU (PWU Share Grant Plan) and one for the benefit of certain members of the Society (formerly the Society of Energy Professionals) (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

## Notes to Amended Consolidated Financial Statements

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 2018, 481,460 common shares were issued under the Share Grant Plans (2017 – 371,611). Total share based compensation recognized during 2018 was \$12 million (2017 – \$17 million) and was recorded as a regulatory asset.

A summary of share grant activity under the Share Grant Plans during years ended December 31, 2018 and 2017 is presented below:

	Share Grants (number of common shares)	Weighted- Average Price
Year ended December 31, 2018		
Share grants outstanding – beginning	4,825,732	\$ 20.50
Vested and issued <sup>1</sup>	(481,460)	—
Forfeited	(110,117)	\$ 20.50
Share grants outstanding – ending	4,234,155	\$ 20.50
1 In 2018, Hydro One issued from treasury 481,460 common shares to eligible employees in accordance with provisions of the PWU and the Society Share Grant Plans.		
Year ended December 31, 2017		
Share grants outstanding – beginning	5,334,415	\$ 20.50
Vested and issued <sup>1</sup>	(371,611)	—
Forfeited	(137,072)	\$ 20.50
Share grants outstanding – ending	4,825,732	\$ 20.50
1 In 2017, Hydro One issued from treasury 371,611 common shares to eligible employees in accordance with provisions of the PWU Share Grant Plan.		

### 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 Director' DSU Plan during the years ended December 31, 2018 and 2017 is presented below:

Year ended December 31 (number of DSUs)	2018	2017
DSUs outstanding – beginning	187,090	99,083
Granted	82,375	88,007
Settled	(222,768)	—
DSUs outstanding – ending	46,697	187,090

## Notes to Amended Consolidated Financial Statements

For the year ended December 31, 2018, an expense of \$1 million (2017 – \$2 million) was recognized in earnings with respect to the Directors' DSU Plan. At December 31, 2018, a liability of \$1 million (2017 – \$4 million) related to Directors' DSUs has been recorded at the December 31, 2018 closing price of the Company's common shares of \$20.25. This liability is included in long-term accounts payable and other liabilities on the Consolidated Balance Sheets.

DSUs related to the Company's former Board of Directors were settled at the June 29, 2018 (last business day in June 2018) closing price of the Company's common shares of \$20.04, with an amount of approximately \$5 million paid during the fourth quarter of 2018.

A summary of DSU awards activity under the Management DSU Plan during the years ended December 31, 2018 and 2017 is presented below:

Year ended December 31 (number of DSUs)	2018	2017
DSUs outstanding – beginning	67,829	–
Granted	40,467	68,897
Paid	–	(1,068)
DSUs outstanding – ending	108,296	67,829

For the year ended December 31, 2018, an expense of \$1 million (2017 – \$2 million) was recognized in earnings with respect to the Management DSU Plan. At December 31, 2018, a liability of \$2 million (2017 – \$2 million) consisted of the following:

- \$1 million recorded at the June 29, 2018 (last business day in June 2018) closing price of the Company's common shares of \$20.04 (2017 – \$22.40) related to previously awarded Management DSUs to the Company's former President and Chief Executive Officer (CEO) included in accounts payable and other current liabilities (2017 – \$1 million included in long-term accounts payable and other liabilities; and
- \$1 million recorded at the December 31, 2018 closing price of the Company's common shares of \$20.25 (2017 – \$22.40) related to other Management DSUs included in long-term accounts payable and other liabilities (2017 – \$1 million).

### 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.

### PSUs and RSUs

A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2018 and 2017 is presented below:

Year ended December 31 (number of units)	PSUs		RSUs	
	2018	2017	2018	2017
Units outstanding – beginning	429,980	230,600	393,430	254,150
Granted	445,120	303,240	345,790	242,860
Vested and issued	(123)	(609)	(106,591)	(14,079)
Forfeited	(31,767)	(103,251)	(31,849)	(89,501)
Settled	(238,030)	–	(158,310)	–
Units outstanding – ending	605,180	429,980	442,470	393,430

### 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.

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 2018, Company contributions made under the ESOP were \$2 million (2017 – \$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.

## Notes to Amended Consolidated Financial Statements

The grant date total fair value of the awards granted in 2018 was \$16 million (2017 – \$13 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2018 was \$15 million (2017 – \$6 million). The expense recognized in 2018 included \$5 million related to previously awarded PSUs and RSUs to the Company's former President and CEO for which costs had not previously been recognized. These awards, consisting of 238,030 PSUs and 158,310 RSUs, were settled in 2018 through a one-time cash settlement arrangement.

### Stock Options

The Company is authorized to grant stock options under its LTIP to certain eligible employees. During 2018, the Company granted 1,450,880 stock options (2017 – nil). The stock options granted are exercisable for a period not to exceed seven years from the date of grant and vest evenly over a three-year period on each anniversary of 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 <sup>1</sup>	\$	20.70
Grant date fair value per option	\$	1.66
Valuation assumptions:		
Expected dividend yield <sup>2</sup>		3.78%
Expected volatility <sup>3</sup>		15.01%
Risk-free interest rate <sup>4</sup>		2.00%
Expected option term <sup>5</sup>		4.5 years

<sup>1</sup> Hydro One common share price on the date of the grant.

<sup>2</sup> Based on dividend and Hydro One common share price on the date of the grant.

<sup>3</sup> Based on average daily volatility of peer entities for a 4.5-year term.

<sup>4</sup> Based on bond yield for an equivalent Canadian government bond.

<sup>5</sup> Determined using the option term and the vesting period.

A summary of stock options activity during 2018 and 2017 is presented below:

Year ended December 31 (number of stock options)	2018	2017
Stock options outstanding – beginning	–	–
Granted <sup>1</sup>	1,450,880	–
Cancelled <sup>2</sup>	(500,970)	–
Stock options outstanding – ending <sup>1</sup>	949,910	–

<sup>1</sup> All stock options granted and outstanding at December 31, 2018 are non-vested.

<sup>2</sup> During 2018, 500,970 stock options previously awarded to the Company's former President and CEO were cancelled. The unrecognized compensation expense related to the cancelled stock options was \$1 million.

The compensation expense related to stock options recognized by the Company during 2018 was \$1 million. At December 31, 2018, there was \$1 million of unrecognized compensation expense related to stock options not yet vested, which is expected to be recognized over a weighted-average period of approximately three years.

## 26. NONCONTROLLING INTEREST

On December 16, 2014, transmission assets totalling \$526 million were transferred from Hydro One Networks to B2M LP. This was financed by 60% debt (\$316 million) and 40% equity (\$210 million). On December 17, 2014, the 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.

## Notes to Amended Consolidated Financial Statements

The following tables show the movements in noncontrolling interest during the years ended December 31, 2018 and 2017:

Year ended December 31, 2018 (millions of dollars)	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	22	50	72
Distributions to noncontrolling interest	(3)	(5)	(8)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	21	49	70

Year ended December 31, 2017 (millions of dollars)	Temporary Equity	Equity	Total
Noncontrolling interest – beginning	22	50	72
Distributions to noncontrolling interest	(2)	(4)	(6)
Net income attributable to noncontrolling interest	2	4	6
Noncontrolling interest – ending	22	50	72

## 27. RELATED PARTY TRANSACTIONS

The Province is a shareholder of Hydro One with approximately 47.4% ownership at December 31, 2018. The Independent Electricity System Operator (IESO), Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB, are related parties to Hydro One because they are controlled or significantly influenced by the Province.

Year ended December 31 (millions of dollars)

Related Party	Transaction	2018	2017
<b>Province</b>	Dividends paid	275	301
<b>IESO</b>	Power purchased	1,636	1,583
	Revenues for transmission services	1,615	1,521
	Amounts related to electricity rebates	477	357
	Distribution revenues related to rural rate protection	239	247
	Distribution revenues related to the supply of electricity to remote northern communities	35	32
	Funding received related to CDM programs	62	59
<b>OPG</b>	Power purchased	10	9
	Revenues related to provision of services and supply of electricity	9	8
	Costs related to the purchase of services	—	1
<b>OEFC</b>	Power purchased from power contracts administered by the OEFC	2	2
<b>OEB</b>	OEB fees	8	8

Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code. Outstanding balances at period end are interest-free and settled in cash.

## 28. CONSOLIDATED STATEMENTS OF CASH FLOWS

The changes in non-cash balances related to operations consist of the following:

Year ended December 31 (millions of dollars)	2018	2017
Accounts receivable	11	195
Due from related parties	(2)	(95)
Other assets	2	8
Accounts payable	2	7
Accrued liabilities	17	(89)
Due to related parties	(68)	10
Accrued interest	(3)	(6)
Long-term accounts payable and other liabilities	(7)	(2)
Post-retirement and post-employment benefit liability	25	85
	<b>(23)</b>	<b>113</b>

## Notes to Amended Consolidated Financial Statements

### 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, 2018 and 2017. The reconciling items include net change in accruals and capitalized depreciation.

Year ended December 31, 2018 (millions of dollars)	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,454)	(121)	(1,575)
Reconciling items	36	1	37
Cash outflow for capital expenditures	(1,418)	(120)	(1,538)

Year ended December 31, 2017 (millions of dollars)	Property, Plant and Equipment	Intangible Assets	Total
Capital investments	(1,493)	(74)	(1,567)
Reconciling items	26	(6)	20
Cash outflow for capital expenditures	(1,467)	(80)	(1,547)

### Capital Contributions

Hydro One enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One. Once the connection

facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One will periodically reassess the estimated of load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to fixed assets in service. In 2018, capital contributions from these reassessments totalled \$7 million (2017 – \$9 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)	2018	2017
Net interest paid	519	475
Income taxes paid	17	12

## 29. CONTINGENCIES

### Legal Proceedings

Hydro One is involved in various lawsuits and claims in the normal course of business. In the opinion of management, the outcome of such matters will not have a material adverse effect on the Company's consolidated financial position, results of operations or cash flows.

Hydro One Inc., Hydro One Networks, Hydro One Remote Communities, and Norfolk Power Distribution Inc. are defendants in a class action suit in which the representative plaintiff is seeking up to \$125 million in damages related to allegations of improper billing practices. The action was commenced in the Superior Court of Ontario on September 9, 2015. The plaintiff's motion for certification was dismissed by the court in November 2017. The plaintiff appealed the court's decision to the Divisional Court. The appeal was heard in October 2018; the Divisional Court dismissed the appeal in December 2018; and in January 2019, the plaintiff applied for leave to appeal to the Ontario Court of Appeal.

To date, four putative class action lawsuits were filed by purported Avista Corporation shareholders in relation to the Merger. First, *Fink v. Morris, et al.*, was filed in Washington state court and the amended complaint names as defendants Avista Corporation's directors, Hydro One, Olympus Holding Corp., Olympus Corp., and Bank of America Merrill Lynch. The suit alleges

that Avista Corporation's directors breached their fiduciary duties in relation to the Merger, aided and abetted by Hydro One, Olympus Holding Corp., Olympus Corp. and Bank of America Merrill Lynch. The Washington state court issued an order staying the litigation until after the Merger has closed. Counsel for the plaintiffs in *Fink* has informally indicated that, in light of the termination of the Merger, the lawsuit will be dismissed, but no formal dismissal papers have been filed with the court at this time. Second, *Jenß v. Avista Corp., et al.*, *Samuel v. Avista Corp., et al.*, and *Sharpenter v. Avista Corp., et al.*, were each filed in the US District Court for the Eastern District of Washington and named as defendants Avista Corporation and its directors; *Sharpenter* also named Hydro One, Olympus Holding Corp., and Olympus Corp. The lawsuits alleged that the preliminary proxy statement omitted material facts necessary to make the statements therein not false or misleading. *Jenß*, *Samuel*, and *Sharpenter* were all voluntarily dismissed by the respective plaintiffs with no consideration paid by any of the defendants.

### 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.

## Notes to Amended Consolidated Financial Statements

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 2018, the Company paid approximately \$2 million (2017 – \$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.

### 30. COMMITMENTS

The following table presents a summary of Hydro One's commitments under leases, outsourcing and other agreements due in the next 5 years and thereafter:

December 31, 2018 (millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Outsourcing and other agreements	161	104	29	2	3	11
Long-term software/meter agreement	17	16	2	1	2	1
Operating lease commitments	7	11	4	1	1	4

#### Outsourcing Agreements

Hydro One has agreements with Inergi LP (Inergi) for the provision of back office and IT outsourcing services, including settlements, source to pay services, pay operations services, information technology and finance and accounting services. The agreement expires on February 28, 2021 for information technology services, on October 31, 2021 for supply chain services, and on December 31, 2019 for the remaining back-office services.

On March 1, 2018, Hydro One insourced its customer service operations, which had been previously outsourced to Inergi and Vertex Customer Management (Canada) Limited since 2002.

Brookfield Global Integrated Solutions (formerly Brookfield Johnson Controls Canada LP) (Brookfield) provides services to Hydro One, including facilities management and execution of certain capital projects as deemed required by the Company. The agreement with Brookfield for these services expires in December 2024, 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, but Hydro One has the option to renew for an additional term of five years at its sole discretion.

#### Operating Leases

Hydro One is committed as lessee to irrevocable operating lease contracts for buildings used in administrative and service-related functions and storing telecommunications equipment. These leases have typical terms of between three and five years, but several leases have lesser or greater terms to address special circumstances and/or opportunities. Renewal options, which are generally prevalent in most leases, have similar terms of three to five years. All leases include a clause to enable upward revision of the rental charge on an annual basis or on renewal according to prevailing market conditions or pre-established rents. There are no restrictions placed upon Hydro One by entering into these leases. During the year ended December 31, 2018, the Company made lease payments totalling \$12 million (2017 – \$12 million).

#### Other Commitments

The following table presents a summary of Hydro One's other commercial commitments by year of expiry in the next 5 years and thereafter:

December 31, 2018 (millions of dollars)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter
Operating Credit Facilities	—	—	250	2,300	—	—
Letters of credit <sup>1</sup>	182	—	—	—	—	—
Guarantees <sup>2</sup>	325	—	—	—	—	—

1 Letters of credit consist of letters of credit totalling \$163 million related to retirement compensation arrangements, a \$13 million letter of credit provided to the IESO for prudential support, \$5 million in letters of credit to satisfy debt service requirements, and \$1 million in letters of credit for various operating purposes.

2 Guarantees consist of prudential support provided to the IESO by Hydro One Inc. on behalf of its subsidiaries.

## Notes to Amended Consolidated Financial Statements

### 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.

## 31. SEGMENTED REPORTING

Hydro One has three reportable segments:

- The Transmission Segment, which comprises the transmission of high voltage electricity across the province, interconnecting more than 70 local distribution companies and certain large directly connected industrial customers throughout the Ontario electricity grid;
- The Distribution Segment, which comprises the delivery of electricity to end customers and certain other municipal electricity distributors; and
- Other Segment, which includes certain corporate activities and the operations of the Company's telecommunications business.

The designation of segments has been based on a combination of regulatory status and the nature of the services provided. Operating segments of the Company are determined based on information used by the chief operating decision maker in deciding how to allocate resources and evaluate the performance of each of the segments. The Company evaluates segment performance based on income before financing charges and income taxes from continuing operations (excluding certain allocated corporate governance costs).

Year ended December 31, 2018 (millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	1,686	4,422	42	6,150
Purchased power	—	2,899	—	2,899
Operation, maintenance and administration	409	602	94	1,105
Depreciation and amortization	435	395	7	837
<b>Income (loss) before financing charges and income taxes</b>	<b>842</b>	<b>526</b>	<b>(59)</b>	<b>1,309</b>
<b>Capital investments</b>	<b>985</b>	<b>577</b>	<b>13</b>	<b>1,575</b>

Year ended December 31, 2017 (millions of dollars)	Transmission	Distribution	Other	Consolidated
Revenues	1,578	4,366	46	5,990
Purchased power	—	2,875	—	2,875
Operation, maintenance and administration	375	593	98	1,066
Depreciation and amortization	420	390	7	817
<b>Income (loss) before financing charges and income taxes</b>	<b>783</b>	<b>508</b>	<b>(59)</b>	<b>1,232</b>
<b>Capital investments</b>	<b>968</b>	<b>588</b>	<b>11</b>	<b>1,567</b>

### Total Assets by Segment:

December 31 (millions of dollars)	2018	2017
Transmission	13,973	13,608
Distribution	9,325	9,259
Other	2,359	2,834
<b>Total assets</b>	<b>25,657</b>	<b>25,701</b>

### Total Goodwill by Segment:

December 31 (millions of dollars)	2018	2017
Transmission	157	157
Distribution	168	168
<b>Total goodwill</b>	<b>325</b>	<b>325</b>

All revenues, assets and substantially all costs, as the case may be, are earned, held or incurred in Canada.

## 32. SUBSEQUENT EVENTS

### (A) Dividends

On February 20, 2019, preferred share dividends of \$5 million and common share dividends of \$137 million (\$0.23 per common share) were declared.

### (B) LTIP

On January 29, 2019, Hydro One issued from treasury 1,905 common shares in accordance with provisions of the LTIP.

### (C) Lake Superior Link Project

On February 15, 2018, Hydro One filed an application with the OEB to construct a transmission line (East-West Tie Line) in northwestern Ontario (Lake Superior Link Project). During 2018, the Company capitalized costs totaling approximately \$11 million associated with this project. On February 11, 2019, the OEB awarded the project to a competitor, as directed by the Province on January 30, 2019. As a result, in the first quarter of 2019, Hydro One recognized an impairment loss of approximately \$11 million associated with previously capitalized costs related to this project.

### (D) OEB Regulatory Decisions

#### Deferred Income Tax Regulatory Asset

Subsequent to year end, on March 7, 2019, the OEB issued a decision on its reconsideration of its Original Decision 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* (Ontario) to tax payments under the federal and provincial tax regime. The OEB's Original Decision concluded that these benefits should not accrue entirely to Hydro One shareholders and that a portion should be shared with ratepayers. The OEB has concluded that the Original Decision was reasonable and should be upheld. The March 7, 2019 OEB decision has been determined to be a Type I subsequent event under US GAAP and as such the Company is required to update the consolidated financial statements to reflect the subsequent event in connection with filing its annual report on Form 40-F with the US Securities and Exchange Commission, so that they reflect events to the date of approval of the Form 40-F. As a result, the financial impact of this OEB decision has been reflected in these amended consolidated financial statements, as more fully discussed in Note 12 – Regulatory Assets and Liabilities.

#### Hydro One Networks' 2018-2022 Distribution Rates

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. This aspect of the decision has been reflected in the adjustments discussed in Note 12 – Regulatory Assets and Liabilities. The other impacts from the OEB decision for Hydro One Networks' 2018-2022 distribution rates will be reflected prospectively in 2019.

# Board of Directors and Senior Leadership Team

## Board of Directors



1. **Tom Woods**, B.A.Sc., MBA, ICD.D  
Former Head of Canadian Corporate Banking, CFO, CRO, Vice Chair CIBC, Director Bank of America Corporation and Alberta Investment Management Corporation, Chair, Unity Health Toronto
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**, LL.M., 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., LL.M.  
Chancellor, Simon Fraser University, Former Canadian President Weyerhaeuser Company Limited, Former Director Nevsun Resources LTD
5. **David Hay**, LL.B., 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. **Timothy Hodgson**, MBA, FCPA, ICD.D  
Managing Partner Alignvest Management Corporation, Former Special Advisor to Bank of Canada Governor Mark Carney, Former

- CEO Goldman Sachs Canada, Director Public Sector Pension Investment Board (PSP Investments), Director MEG Energy, Director Alignvest Acquisition II Corporation
7. **Jessica McDonald**, ICD.D  
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
8. **Russel Robertson**, FCPA, FCA, ICD.D  
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
9. **William Sheffield**, B.Sc., MBA, ICD.D  
Director, Former CEO Sappi Fine Papers, Director, Houston Wire & Cable Company, Director, Velan Inc., Former Board Member OPG
10. **Melissa Sonberg**, B.Sc., MHA, ICD.D  
Adjunct Professor, 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

## Senior Leadership Team



11. **Paul Dobson**  
Acting President and CEO
12. **Jason Fitzsimmons**  
Chief Corporate Affairs and Customer Care Officer
13. **Greg Kiraly**  
Chief Operating Officer
14. **Chris Lopez**  
Acting Chief Financial Officer
15. **Judy McKellar**  
EVP, Chief Human Resources Officer
16. **Patrick Meneley**  
EVP, Chief Corporate Development Officer
17. **James (Jamie) Scarlett**  
EVP, Chief Legal Officer

For detailed biographical information of Hydro One Limited Board members and senior leadership, go to [www.HydroOne.com/Investors](http://www.HydroOne.com/Investors).

The biographical information of Hydro One Limited Board members is based on information available to management as of March 8, 2019.

# Corporate and Shareholder Information

## Corporate Offices

483 Bay Street, South Tower  
Toronto, ON  
M5G 2P5  
1.416.345.5000  
www.HydroOne.com

## Customer Inquiries

Customer Service:  
1.888.664.9376 or  
CustomerCommunications@HydroOne.com  
Report an Emergency (24 hours):  
1.800.434.1235

## Shareholder Services

If you are a registered shareholder and have inquiries regarding your account, wish to change your name or address, or have questions about dividends, duplicate mailings, lost stock certificates, share transfers or estate settlements, contact our transfer agent and registrar:

Computershare Trust Company of Canada  
100 University Avenue, 8th Floor  
Toronto, ON  
M5J 2Y1  
1.514.982.7555 or 1.800.564.6253  
service@computershare.com

## Institutional Investors and Analysts

Institutional investors, securities analysts and others requiring additional financial information can visit [www.HydroOne.com/Investors](http://www.HydroOne.com/Investors) or contact us at: 1.416.345.6867  
Investor.Relations@HydroOne.com or  
Omar.Javed@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/OurCommitment](http://www.HydroOne.com/OurCommitment) or email [CSR@HydroOne.com](mailto:CSR@HydroOne.com).

## Stock Exchange Listing

Toronto Stock Exchange (TSX): H  
(CUSIP #448811208)



## Independent Auditors

KPMG LLP

## Equity Index Inclusions

Dow Jones Select Utilities (Canada) Index  
FTSE All-World Index Series  
MSCI World (Canada) Index  
S&P/TSX Composite Index  
S&P/TSX Utilities Index  
S&P/TSX Composite Dividend Index  
S&P/TSX Composite Low Volatility Index  
S&P/TSX Composite High Dividend Index

## Debt Securities

For details of the public debt securities of Hydro One and its subsidiaries, please refer to the "Debt Information" section under [www.HydroOne.com/Investors](http://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](http://www.HydroOne.com/Investors) where you will find additional information about our business, including events and presentations, news releases, regulatory filings, governance practices, corporate social responsibility 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

### 2019 Expected Dividend Dates \*

Record Date	Payment Date
March 13, 2019	March 29, 2019
June 12, 2019	June 28, 2019
September 12, 2019	September 30, 2019
December 11, 2019	December 31, 2019

\*Subject to Board approval

Unless indicated otherwise, all common share dividends paid by Hydro One are designated as "eligible" dividends for the purposes of the *Income Tax Act* (Canada) and any similar provincial legislation.

## Dividend Reinvestment Plan (DRIP)

Hydro One offers a convenient dividend reinvestment program for eligible shareholders to purchase additional Hydro One shares by reinvesting their cash dividends without incurring brokerage or administration fees. For plan information and enrolment materials or to learn more about the Hydro One DRIP, visit [www.HydroOne.com/DRIP](http://www.HydroOne.com/DRIP) or Computershare Trust Company of Canada at [www.InvestorCentre.com/HydroOne](http://www.InvestorCentre.com/HydroOne).

## Regulatory Stakeholders

Hydro One is committed to understanding the interests of maintaining and enhancing long-term relationships with its regulatory stakeholders.



Provincial Government,  
Ministry of Energy  
Policy, legislation, regulations



Ontario Energy Board (OEB)  
Independent electric utility price  
and service quality regulation



Independent Electricity System Operator  
Wholesale power market rules,  
intermediary, North American  
reliability standards



Canada  
National Energy Board  
Federal regulator, international  
power lines and substations



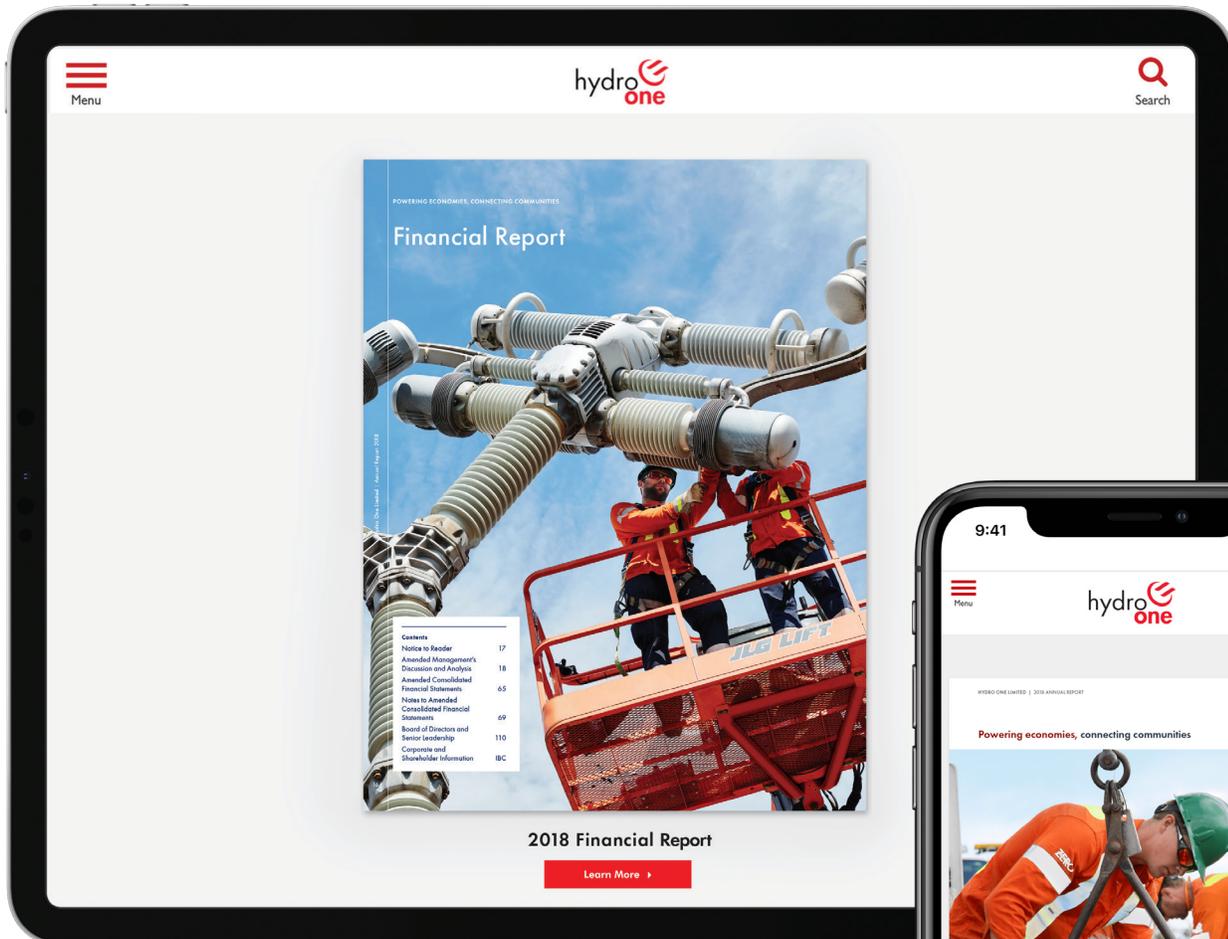
North American Electric  
Reliability Corporation  
Continent-wide bulk power reliability  
standards, certification, monitoring

For more information, visit:  
[www.HydroOne.com/Regulatory](http://www.HydroOne.com/Regulatory)



## Mixed Sources

Product group from well-managed  
forests, controlled sources and  
recycled wood or fiber  
[www.fsc.org](http://www.fsc.org) Cert no. XXX-XXX-000  
© 1996 Forest Stewardship Council



## 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](http://www.HydroOne.com)



FOLLOW HYDRO ONE



1 **DRAFT ISSUES LIST**

2  
3 **A. GENERAL**

- 4 1. Has B2M LP responded appropriately to all relevant Ontario Energy Board  
5 (“OEB”) directions from previous proceedings?  
6 2. Are all elements of the proposed revenue requirement and their associated total  
7 bill impacts reasonable?  
8

9 **B. REVENUE CAP APPLICATION**

- 10 3. Is the proposed Incentive Rate Methodology consistent with the OEB’s *Rate*  
11 *Handbook*?  
12 4. Are the proposed industry-specific inflation factor and the proposed productivity  
13 factor appropriate?  
14 5. Are the proposed annual updates appropriate?  
15 6. Is the proposed Earnings Sharing Mechanism appropriate?  
16

17 **C. TRANSMISSION SYSTEM PLAN**

- 18 7. Does the investment planning process consider appropriate planning criteria?  
19 Does it adequately address the condition of the transmission system assets?  
20

21 **D. PERFORMANCE**

- 22 8. Is the proposed monitoring and reporting of performance adequate?  
23

24 **E. OPERATIONS MAINTENANCE & ADMINISTRATION COSTS**

- 25 9. Are the proposed spending levels for OM&A in 2020 appropriate, including  
26 consideration of factors such as system reliability and asset condition?  
27 10. Are the amounts proposed to be included in the revenue requirement for income  
28 taxes appropriate?

Witness: Kathleen Burke

1           11. Is the proposed depreciation expense appropriate?  
2

3           **F. RATE BASE & COST OF CAPITAL**

4           12. Are the amounts proposed for rate base and capital structure reasonable?

5           13. Is the forecast of long-term debt appropriate?

6           14. Is the 2021 update of the cost of long-term debt appropriate?  
7

8           **G. DEFERRAL/VARIANCE ACCOUNTS**

9           15. Are the proposed amounts, disposition and continuance of existing deferral and  
10           variance accounts appropriate?

11          16. Are the proposed new deferral and variance accounts appropriate?  
12

13          **H. COST ALLOCATION**

14          17. Is the proposed cost allocation appropriate?

**LIST OF WITNESSES**

1

2

3 To be filed behind this tab if the OEB determines that an oral hearing is required.

**CURRICULA VITAE**

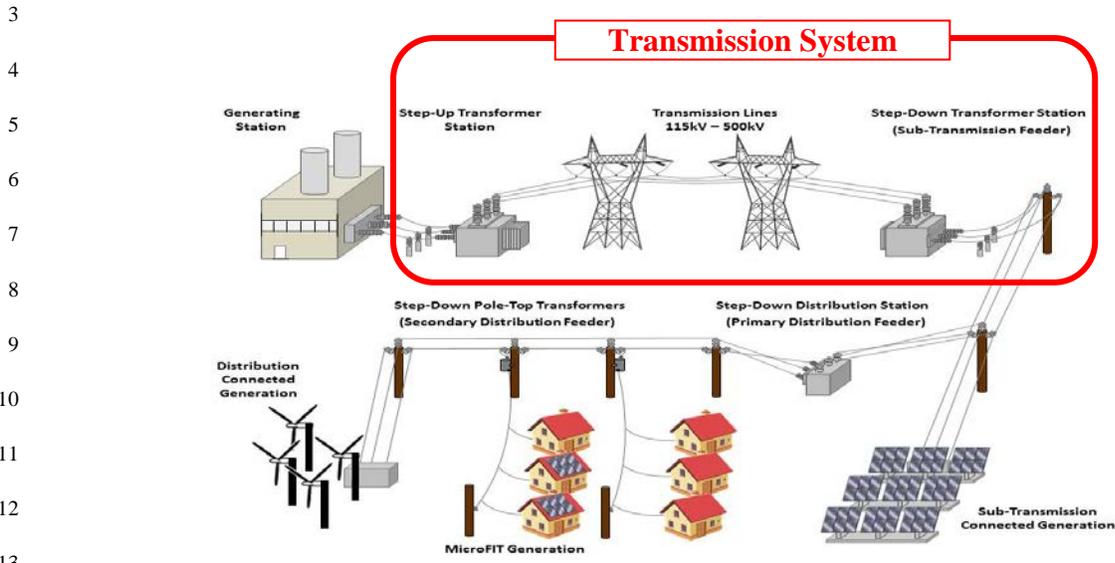
1

2

3 Curricula Vitae information will be filed prior to the oral hearing.



1 B2M LP transmission assets are limited to an individual 500kV double circuit  
2 transmission line, as presented in the following section.



14 **Figure 1 - Simplified Transmission System**

15  
16 **3. DESCRIPTION OF B2M LP TRANSMISSION ASSETS**

17  
18 B2M LP's transmission assets are comprise solely one 500kV double circuit transmission  
19 line, known as Circuit B560V and Circuit B561M, which has a combined capacity of  
20 approximately 3,000 MW.

21  
22 The route of B2M LP's 500kV double circuit transmission line runs parallel to a pre-  
23 existing 500kV double circuit transmission line between the Bruce Power Complex and  
24 Milton SS, as depicted in the map in Figure 2 below, passing through Bruce, Grey,  
25 Wellington, and Dufferin counties; the regional municipality of Halton; and the  
26 municipalities of Kincardine, Brockton, Hanover, West Grey, Southgate, Wellington  
27 North, Erin, East Luther Grand Valley, East Garafraxa, Halton Hills and Milton.

1 B2M LP's assets include the new double circuit line from Bruce Power Complex at  
2 Kincardine to a point near Highway 7 just east of Acton, where the new double circuit  
3 joins a short section of pre-existing 500kV double circuit line which carries on from  
4 Highway 7 south to Milton SS. Each circuit is approximately 176 km in length, and they  
5 form a contiguous line from Bruce Power Complex to Milton SS. HONI owns the  
6 terminating stations (Bruce A TS, Bruce B SS, and Milton SS).

7  
8 The demarcation point of each of B2M LP's circuits from Hydro One's transmission  
9 system is:

- 10 • Circuit B560V: terminating at the north end near Bruce A TS at tower #2A,  
11 inclusive, and at the south end at Milton SS at tower #726, inclusive; and
- 12 • Circuit B561M: terminating at the north end near Bruce B SS at tower #2,  
13 inclusive, and at the south end at Milton SS at tower #726, inclusive.

14  
15 The major components of these circuits include overhead conductors, steel support  
16 structures and foundations, insulators, and connecting hardware and grounding systems.  
17 B2M LP also has rights to HONI's existing transmission corridor on which the circuits  
18 are located. A summary of B2M LP's key assets are provided in Table 1. For a further  
19 description of B2M's transmission assets, please refer to B2M's first Transmission  
20 System Plan presented in Attachment 1 of Exhibit B, Tab 1, Schedule 3.

21  
22 **Table 1 - Asset Summary**

<b>B2M LP Assets</b>	
Fixed Assets (Net Book Value)	\$498 Million*
Transmission System Voltages	500kV
Overhead Transmission Lines	352 circuit km
Steel Support Structures	710 towers
Line Insulators	5,100 strings

23 *\*Value as of December 31, 2018 as documented in Exhibit C, Tab 2, Schedule 4.*

Witness: Donna Jablonsky

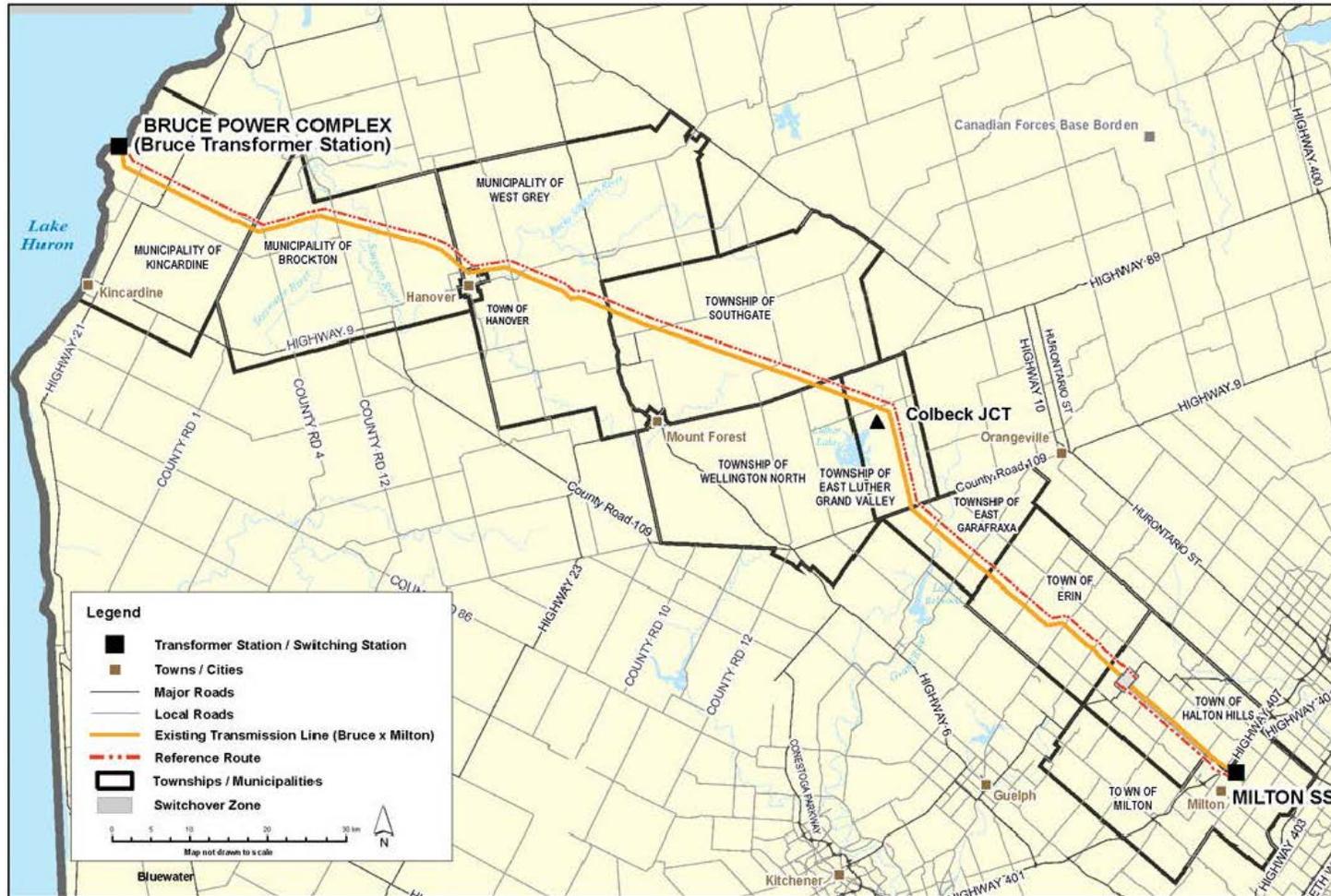


Figure 2 - Transmission System Map

1 **4. ELECTRICITY INDUSTRY AND REGULATORY FRAMEWORK**

2  
3 B2M LP is subject to direction from its owners, OEB decisions, and government  
4 legislation and regulations. Each of these sources has the potential to be a driver for  
5 change affecting B2M LP policies, processes and work programs. When new legislation  
6 or regulations are passed and when OEB decisions are released, B2M LP responds by  
7 developing appropriate programs or initiatives to implement the required changes in a  
8 cost-effective fashion.

9  
10 The following provides a summary of the key electricity legislation and regulation,  
11 industry standards and guidelines and other relevant legislation that governs and drives  
12 B2M LP's transmission business.

13  
14 **4.1 INDUSTRY AND REGULATORY ENVIRONMENT IN ONTARIO**

15  
16 Within the Ontario electricity industry, the Ministry of Energy, Northern Development  
17 and Mines sets legislative and regulatory requirements through changes to the *Electricity*  
18 *Act, 1998* and the *Ontario Energy Board Act, 1998*.

19  
20 The OEB sets transmission rates, issues codes and licences, and grants approval for  
21 construction of new transmission lines greater than two kilometres. The Transmission  
22 System Code ("TSC"), issued by the OEB, sets out the obligations of electricity  
23 transmitters regarding their customers. The TSC also addresses standards for the  
24 operation, maintenance, management and expansion of transmission systems. B2M LP is  
25 bound by the terms of its transmission licence to adhere to the requirements of the TSC  
26 and is required to operate and maintain its system in accordance with "good utility  
27 practice". The TSC and the Independent Electricity Operator's (IESO's) Market Rules  
28 also require all customers directly connected to the transmission system to enter into a

Witness: Donna Jablonsky

1 connection agreement with their transmitter. Direct customer connections to the 500kV  
2 system in Ontario are very rare. At the present time, B2M LP does not have any  
3 customers that are directly connected to its assets. B2M LP will establish agreements  
4 with transmission customers if required in the future.

5  
6 The IESO administers the electricity market and directs the operation of the power  
7 system in Ontario while ensuring that its extensive planning, conservation, market and  
8 procurement capabilities serve the province's long-term needs. The IESO-controlled grid  
9 provides the infrastructure for transmitting large volumes of electrical energy from major  
10 generation sources to major load centres. The B2M LP transmission assets provide  
11 transmission capacity, which the IESO makes available to market participants.

## 12 13 **4.2 NORTH AMERICAN RELIABILITY FRAMEWORK**

14  
15 The National Electric Reliability Council ("NERC") was established in the United States  
16 in 1968, in response to the 1965 blackout, to ensure the reliability of the North American  
17 bulk power system. NERC is subject to oversight by governmental authorities in Canada  
18 and the United States. NERC develops and enforces reliability standards, monitors the  
19 bulk power system, and assesses and reports on future transmission and generation  
20 adequacy.

21  
22 Following the 2003 Northeast blackout, the *U.S. Energy Policy Act* of 2005 authorized  
23 the creation of a self-regulatory Electricity Reliability Organization ("ERO") that would  
24 span North America. The legislation stated that compliance with reliability standards  
25 would be mandatory and enforceable. In July 2006, NERC was certified as the ERO in  
26 the United States. In October 2006, the OEB signed a Memorandum of Understanding  
27 with NERC recognizing NERC as the ERO in Ontario. According to this Memorandum  
28 of Understanding and the IESO's Market Rules, only the IESO is directly subject to the

Witness: Donna Jablonsky

1 Compliance Monitoring and Enforcing Program of NERC and NPCC in Ontario. The  
2 IESO, through its Market Assessment and Compliance Division, in turn, enforces the  
3 NERC reliability standards and NPCC criteria through the Market Rules.

4  
5 As a licensed transmitter, B2M LP has a regulatory obligation to comply with the  
6 planning, operating, and reliability criteria and standards adopted by NERC and NPCC as  
7 stated in the IESO Market Rules. The IESO is responsible for monitoring and enforcing  
8 the reliability standards in Ontario, where market participants are subject to monetary  
9 sanctions for confirmed violations.

#### 11 **4.3 OTHER RELEVANT LEGISLATION**

##### 13 **4.3.1 ENVIRONMENTAL LEGISLATION**

14 B2M LP is subject to a wide range of federal and provincial legislation, regulation and  
15 standards related to environmental impacts. The following are the major statutes that  
16 govern B2M LP's activities. Many others can apply in specific circumstances, but the  
17 following are applicable to most transmission work:

- 18 *1. Environmental Assessment Act*
- 19 *2. Environmental Protection Act*
- 20 *3. Fisheries Act / Fish and Wildlife Conservation Act, 1997*
- 21 *4. Species at Risk Act / Endangered Species Act, 2007*
- 22 *5. Dangerous Goods Transportation Act*
- 23 *6. Pesticides Act*
- 24 *7. Ontario Water Resources Act*
- 25 *8. Conservation Authorities Act*
- 26 *9. Ontario Heritage Act*
- 27 *10. Forest Fires Prevention Act*
- 28 *11. Public Lands Act*

Witness: Donna Jablonsky

1            *12. Public Transportation and Highway Improvement Act*

2  
3            **4.3.2 SAFETY STANDARDS**

4            Safety is of utmost importance in B2M LP's transmission work activities. B2M LP is  
5            committed to complying with safety standards and regulations following those  
6            established by HONI. The *Occupational Health and Safety Act* requires B2M LP to  
7            comply with industrial design and construction safety regulations, and B2M LP must also  
8            comply with the health regulations of the Ministry of Health under the *Health Protection*  
9            *and Promotion Act*.

10  
11           **4.3.3 INDUSTRY STANDARDS**

12           B2M LP also complies with other relevant national and international standards such as  
13           the Canadian Standards Association ("CSA"), the Institute of Electrical and Electronic  
14           Engineers ("IEEE") and the International Electrotechnical Commission ("IEC") for the  
15           design of its transmission system and equipment.

16  
17           **4.4 COMPLIANCE MATTERS**

18           Pursuant to the Filing Requirements, B2M LP states that there are no outstanding areas of  
19           non-compliance which have had an effect on this Application, and B2M LP is therefore  
20           not seeking any relief to resolve any non-compliance issues.

1  
2  
3  
4  
5  
6  
7  
8  
9  
10  
11  
12  
13  
14  
15  
16  
17  
18  
19  
20  
21  
22  
23  
24

## STRATEGIC PLAN

### 1. INTRODUCTION

B2M LP is a Limited Partnership between Hydro One Indigenous Partnerships GP Inc. (“HOIP”), formerly known as B2M GP Inc., and Hydro One B2M LP Inc. (both affiliates of Hydro One Inc.), and Saugeen Ojibway Nation Finance Corporation (“SON FC”), a corporation owned by, and nominee of, the Chippewas of Saugeen First Nation and Chippewas of Nawash First Nation. This Exhibit provides an overview of B2M LP’s business activities and values utilized in the development of an overall strategy for the company. It also will outline B2M LP’s strategic goals and vision that drives the partnership’s five-year plan as presented in this Application.

### 2. DESCRIPTION OF B2M LP BUSINESS ACTIVITIES

B2M LP is licensed by the Ontario Energy Board (“OEB”) to own, operate and maintain transmission facilities in the Province of Ontario. B2M LP’s business activities consist of the management of its transmission assets to meet reliability standards and satisfy regulatory, environmental, and legal requirements. HOIP, the general partner of B2M LP, is responsible for ensuring that the transmission assets owned by B2M LP are operated and maintained in accordance with these requirements. HOIP will carry out these functions through an operations services and management services agreement with Hydro One Networks Inc. (“HONI”), a copy of which is included as Attachment 1 to Exhibit F, Tab 3, Schedule 1.

Witness: Jeffrey Smith

1    **3.    B2M LP'S VALUES**

2  
3    B2M LP, as part of the Hydro One family of companies, is driven primarily by the values  
4    of health and safety, and stewardship. B2M LP conducts work in an environment that  
5    can be dangerous for both workers and the public. Therefore, safety is of the utmost  
6    importance. The partnership demonstrates sound stewardship in a manner that respects  
7    customers' needs and the environment. B2M LP's strategy and business values must  
8    operate with rates that can balance the financing of investment in infrastructure while  
9    maintaining affordable and reliable service.

10  
11   Furthermore, B2M LP is 34% owned by a partnership of First Nations over whose  
12   traditional territory the transmission line crosses. Respect for Indigenous peoples and  
13   their traditions is another key value of the partnership.

14  
15    **4.    STRATEGIC OBJECTIVES**

16  
17    B2M LP's strategic objectives consist of the following:

- 18       •    Oversee a service level agreement with HONI that supports creating an injury-  
19       free workplace and maintaining public safety;
- 20       •    Foster relationships with the owners of the partnership and the Indigenous  
21       communities;
- 22       •    Maintain a reliable, cost-effective transmission system;
- 23       •    Protect and sustain the environment for future generations;
- 24       •    Maintain a commercial culture that increases value for its owners; and
- 25       •    Achieve productivity improvements and cost effectiveness.

26  
27    The five-year vision associated with B2M LP's strategic objectives is shown in Table 1.  
28    In managing its transmission assets, B2M LP is committed to meeting the OEB's

Witness: Jeffrey Smith

1 Renewed Regulatory Framework (“RRF”) outcomes as demonstrated by the alignment of  
 2 B2M LP’s strategic objectives to the RRF outcomes.

3  
 4

**Table 1 - B2M LP Strategic Objectives**

<b>RRF Outcomes</b>	<b>Strategic Objectives</b>	<b>Five-Year Vision</b>
Customer Focus	Foster Indigenous Relationships	Continue to maintain effective and beneficial relationships.
Operational Effectiveness	Injury-Free	Ensure B2M LP’s operations and management services agreement is executed in accordance with good utility practice for employee and public safety.
	Reliable Transmission	Continue to maintain a reliable transmission system.
	Cost Control	Strive to minimize costs and pass on savings to the customers of the province.
Public Policy Responsiveness	Protecting the Environment	Sustainably manage B2M LP’s environmental footprint.
Financial Performance	Owner’s Value	Achieve the Regulated Return On Equity allowed by the Ontario Energy Board.

5

6 These strategic objectives underpin and drive B2M LP’s business. In the implementation  
 7 of these strategic objectives, B2M LP works directly with HONI to review maintenance  
 8 programs and optimize work plans for efficiency, reliability and safety. The financial  
 9 performance of B2M LP is also closely monitored and the timing of expenditures  
 10 adjusted as required to maintain partner returns at expected levels. Furthermore, B2M LP  
 11 is proposing to track its performance by utilizing a set of outcome measures as  
 12 documented in Exhibit D, Tab 1, Schedule 1 to ensure that B2M LP satisfies its five year  
 13 plan.

14

15 Like other transmitters, B2M LP may face challenges in implementing its plan to achieve  
 16 the objectives listed above. External factors, such as: unforeseen weather events and  
 17 material changes to codes and standards, etc., can cause necessary changes in  
 18 implementation of the plan that may not have been expected at time of planning.  
 19 Resourcing can also affect the timing of work execution. However, the work itself must  
 20 be completed to ensure compliance with regulatory requirements and good utility

Witness: Jeffrey Smith

1 practice, and to ensure that expenses will not lead to deficient returns. The communities  
2 that the Indigenous partners serve are modest entities that are financially unable to sustain  
3 substantial losses of return without affecting the delivery of important services to their  
4 members. Therefore, consistent returns for B2M LP are crucial.



1 the control of the transmitter's ability to manage, such as storms causing damage to its  
2 assets.

3

4 To date, B2M LP has not utilized the z-factor mechanism prescribed in the previous  
5 decision. However, B2M LP will be undertaking a small amount of unplanned capital  
6 expenditures in 2019 to address an insulator defect related to cement expansion that  
7 results in premature and unpredictable failure. Further details about the necessity of this  
8 investment and B2M LP's proposed approach to include this amount into the rate base for  
9 2020 are provided in Exhibit C, Tab 1, Schedule 1.

# Transmission System Plan

---

Historical Period and Bridge Year: 2015-2019

Test Year and Forecast Period: 2020-2024



**B2M | LIMITED PARTNERSHIP**

## Table of Contents

<b>1.0</b>	<b>INTRODUCTION.....</b>	<b>3</b>
<b>2.0</b>	<b>TRANSMISSION SYSTEM PLAN .....</b>	<b>4</b>
2.1	Transmission system plan overview ( <i>OEB Filing Req. 5.2.1</i> ).....	4
2.2	Coordinated planning with third parties ( <i>OEB Filing Req. 5.2.2</i> ).....	6
2.3	Performance measurement for continuous improvement ( <i>OEB Filing Req. 5.2.3</i> ).....	6
2.4	Realized efficiencies due to smart meters ( <i>OEB Filing Req. 5.2.3</i> ) .....	7
<b>3.0</b>	<b>ASSET MANAGEMENT PROCESS .....</b>	<b>8</b>
3.1	Asset management process overview ( <i>OEB Filing Req. 5.3.1</i> ).....	8
3.2	Overview of assets managed ( <i>OEB Filing Req. 5.3.2</i> ) .....	8
3.3	Asset lifecycle optimization policies and practices ( <i>OEB Filing Req. 5.3.3</i> ).....	12
3.4	System capability assessment renewable energy generation ( <i>OEB Filing Req. 5.3.4</i> )...	15
<b>4.0</b>	<b>CAPITAL EXPENDITURE PLAN.....</b>	<b>16</b>
4.1	Capital planning process overview ( <i>OEB Filing Req. 5.4.1</i> ).....	16
4.2	Capital expenditure summary ( <i>OEB Filing Req. 5.4.2</i> ).....	16
4.3	Justifying capital expenditures ( <i>OEB Filing Req. 5.4.3</i> ) .....	17

1 **1.0 INTRODUCTION**

2  
3 B2M Limited Partnership (“B2M LP”) prepared this 2020 to 2024 Transmission System  
4 Plan (“TSP”) in accordance with Chapter 2 of the Ontario Energy Board’s (“OEB”) *Filing Requirements for Electricity Transmission Applications* published on February 11,  
5 2016, with further guidance from Chapter 3 and 5 of the OEB’s *Filing Requirements (Incentive Regulation and Consolidated Distribution System Plan Filing Requirements)*,  
6 revised on July 12, 2018 (together, the “Filing Requirements”).  
7  
8

9  
10 B2M LP submits that this TSP is distinct from most Transmission and Distribution  
11 System Plans submitted to the OEB in that it is not being filed to support any capital  
12 funding. Accordingly, the planning tools, processes, and investments outlined in this TSP  
13 represent the current state of the assets owned by the partnership, and this TSP is  
14 submitted to support the information purposes of ratepayers and stakeholders.

1 **2.0 TRANSMISSION SYSTEM PLAN**

2  
3 **2.1 TRANSMISSION SYSTEM PLAN OVERVIEW (*OEB Filing Req. 5.2.1*)**

4 This section summarizes the key components that make up the integrated TSP and  
5 contextualizes the quantitative and qualitative information provided throughout.

6  
7 **2.1.1 Key Elements of the Plan:**

8 B2M LP transmission assets are limited to the components of a single 500kV double  
9 circuit transmission line. Given the relatively new vintage of this line, no planned capital  
10 spending is required to meet the Applicant's business objectives over the 2020 to 2024  
11 planning period. The absence of capital spending is expected to result in no in-service  
12 additions to grow the rate base of the Applicant during the planning period.

13  
14 The forecast OM&A is a relatively small portion of the rate proposal, representing  
15 approximately 3.5% of revenue requirement. The proposed OM&A will ensure that the  
16 B2M LP assets are operated and maintained in accordance with good utility practice and  
17 reliability standards.

18  
19 **2.1.2 Customers' Preferences and Expectations:**

20 B2M LP's 500kV double circuit transmission line is part of Ontario's bulk electric  
21 system, which helps to ensure the adequacy of supply to the province by connecting to  
22 major generating sources and delivering that power to major load centres in Ontario.  
23 B2M LP has no delivery points and therefore has no customers that it directly serves;  
24 thus, the partnership has not performed any independent customer research.

25  
26 Customer research undertaken by other transmitters (e.g. Hydro One Networks Inc.)  
27 shows that most customers in Ontario want low rates and high reliability. B2M LP's five-  
28 year plan supports these general customer objectives by proposing no planned capital  
29 spending and a minimal OM&A budget required to maintain B2M LP's transmission

Witness: Donna Jablonsky/Jeffrey Smith

1 reliability. B2M LP is renewing its Agreement with Hydro One Networks Inc. (“HONI”)  
2 to continue providing maintenance and operational services on the transmission line for  
3 the next five years. Having this service provider, with its breadth of capabilities and local  
4 knowledge, provides assurance that the assets will be operated and maintained in  
5 accordance with good utility practice and reliability standards.

6  
7 **2.1.3 Anticipated Sources of Efficiencies:**

8 The majority of B2M LP’s OM&A services (accounting for approximately 75% of the  
9 2020 forecast) are provided by HONI through a Service Level Agreement. The  
10 Agreement and the charges therefrom are in accordance with the Affiliate Relationships  
11 Code and are billed on the lower of cost and market price. Efficiencies gained by HONI  
12 are passed through to B2M LP. B2M LP’s asset is a 500kV double circuit transmission  
13 line that is located directly adjacent to a comparable line owned by HONI. Given the  
14 proximity of the assets, there are meaningful efficiencies inherent in having one party,  
15 HONI, plan and perform the work on both lines simultaneously.

16  
17 B2M LP’s controllable costs are minimal but do include certain administrative expenses.  
18 Over the past period, B2M LP has been able to recognize modestly lower costs in such  
19 things as insurance and the Managing Director’s office, which are being passed through  
20 to ratepayers in this Application.

21  
22 **2.1.4 Period Covered and Vintage of Information:**

23 This TSP covers a five-year historical period of 2015 to 2019, and a five-year forecast  
24 period from 2020 to 2024 inclusive. The information contained in this TSP is considered  
25 current as of year-end of 2018, unless otherwise noted.

26  
27 **2.1.5 Important Changes to the Asset Management Process:**

28 B2M LP has not made any changes to the manner in which it manages its assets. B2M  
29 LP continues to retain HONI under a Service Level Agreement to plan and organize the

Witness: Donna Jablonsky/Jeffrey Smith

1 operation and maintenance of the assets and provide certain corporate and administrative  
2 support. B2M LP relies upon HONI's asset management process to develop its plan, as  
3 articulated in Section 3.1 Asset Lifecycle Optimization Policies and Practices below.

4  
5 **2.1.6 Contingencies of Plan:**

6 B2M LP is not proposing a capital plan over the five-year term of this Application;  
7 therefore, there are no contingencies of plan required.

8  
9 **2.1.7 Grid Modernization:**

10 At this time, B2M LP is not implementing any capital plans for future initiatives such as  
11 distributed energy resources, grid modernization or climate change.

12  
13 **2.2 COORDINATED PLANNING WITH THIRD PARTIES** *(OEB Filing Req. 5.2.2)*

14 B2M LP is not a lead transmitter for any of the regional planning regions. B2M LP owns  
15 only one 500kV double circuit transmission line, which is part of the bulk system. The  
16 bulk system planning is under the purview of the Independent Electricity System  
17 Operator ("IESO") and is coordinated as part of that undertaking. If requested, B2M LP  
18 would participate in the bulk system planning process and/or regional bulk system  
19 planning process, as per Section 3C of the Transmission System Code and the OEB  
20 endorsed Planning Process Working Group (the "PPWG") Report, in compliance with  
21 B2M LP's obligations as a licensed transmitter. To date, B2M LP has not received such  
22 a request and is not expecting such a request in the foreseeable future.

23  
24 **2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT**  
25 *(OEB Filing Req. 5.2.3)*

26 B2M LP is proposing to continue to track its performance by utilizing the measures  
27 approved by the OEB in proceeding EB-2015-0026 to ensure that B2M LP is meeting its  
28 five-year plan as described in this Application. The performance measures will be tracked  
29 annually, and the results of this tracking will be reported to the OEB at the next

Witness: Donna Jablonsky/Jeffrey Smith

1 proceeding. Further details on the methods and measures, as well as on the historical  
2 performance and forecast targets, are documented in Exhibit D, Tab 1, Schedule 1.

3

4 **2.4 REALIZED EFFICIENCIES DUE TO SMART METERS (*OEB Filing Req. 5.2.3*)**

5 B2M LP is a licensed transmitter of a 500kV double circuit transmission line but does not  
6 own any operable station assets and does not directly serve any customers. Therefore, the  
7 Applicant has neither deployed nor operationalized any smart meters or related  
8 technologies.

1 **3.0 ASSET MANAGEMENT PROCESS**

2  
3 **3.1 ASSET MANAGEMENT PROCESS OVERVIEW (*OEB Filing Req. 5.3.1*)**

4 B2M LP seeks to identify and prioritize asset maintenance and capital investments in an  
5 optimal way throughout the life cycle of its assets. To achieve this goal, B2M LP works  
6 with HONI to undertake a strategic and methodical asset management process, drawing  
7 upon HONI's extensive expertise and experience to monitor its transmission system  
8 assets, identify and define needs, and determine the optimal timing for investment and  
9 maintenance activities. In doing so, B2M LP strives to ensure that it can continue to  
10 deliver, over the long term, a level of transmission service that is responsive to  
11 operational needs, while also minimizing rate impacts and risks in support of the  
12 company's strategic objectives.

13  
14 **3.2 OVERVIEW OF ASSETS MANAGED (*OEB Filing Req. 5.3.2*)**

15 This section summarizes the detailed characteristics and data on the assets covered by the  
16 asset management process, including service area, system configuration, asset condition,  
17 and asset utilization.

18  
19 **3.2.1 Features of the Service Area (*OEB Filing Req. 5.3.2A*)**

20 B2M LP's 500kV double circuit transmission line passes through Bruce, Grey,  
21 Wellington, and Dufferin counties; the regional municipality of Halton; and the  
22 municipalities of Kincardine, Brockton, Hanover, West Grey, Southgate, Wellington  
23 North, Erin, East Luther Grand Valley, East Garafraxa, Halton Hills and Milton, as noted  
24 in Figure 2 in Exhibit B, Tab 1, Schedule 1. These are primarily rural areas that generally  
25 allow for easy access to perform maintenance activities. However, the climate in these  
26 areas varies by season and is susceptible to a variety of extreme weather conditions, such  
27 as blizzards, hail, ice storms, lightning, thunderstorms, extreme heat and tornadoes.

1 **3.2.2 System Configuration (*OEB Filing Req. 5.3.2B*)**

2 An overview of B2M LP’s 500kV double circuit transmission line (Circuit B560V and  
3 Circuit B561M), including route and demarcation points of each circuit relative to  
4 HONI’s transmission system, is presented in Section 3.0 of Exhibit B, Tab 1, Schedule 1.  
5 Table 1 provides a high-level description and quantity of major transmission assets that  
6 comprise this transmission line.

7  
8 **Table 1: Asset Summary**

<b>Asset Type</b>	<b>Description</b>	<b>Quantity</b>
<b>Conductor</b>	The conductor of an overhead transmission line is the asset responsible for transporting electricity between system nodes.	352 km
<b>Steel Towers</b>	Steel structures elevate transmission lines above the ground, providing clearance from ground objects and separation between the circuit conductors and other line components.	710 structures
<b>Insulators</b>	Insulators provide mechanical support for overhead conductors and must provide electrical isolation between the energized conductors they support and the grounded towers to which they are attached.	5,100 strings

9  
10 These asset types are similar to those on HONI’s transmission system. For further  
11 detailed asset descriptions please refer to HONI’s Transmission Rate Application (EB-  
12 2019-0028) in Exhibit B, Tab 1, Section 1, TSP Section 2.2.2.

13  
14 **3.2.3 Asset Condition (*OEB Filing Req. 5.3.2C*)**

15 This section presents the service profile and condition of B2M LP’s key transmission  
16 assets.

17  
18 **In-Service Profile**

19 The asset profile, as noted in Table 2, provides the average age of the components and the  
20 Expected Service Life (“ESL”). The ESL is defined as the average time duration in years  
21 that an asset can be expected to operate under normal system conditions and is  
22 determined by considering manufacturer guidelines and HONI’s historical asset

Witness: Donna Jablonsky/Jeffrey Smith

1 retirement data. Assets operating beyond ESL generally have a higher likelihood of  
2 failing or being in poor condition.

3  
4 **Table 2: Asset Service Profile**

<b>Asset Type</b>	<b>Quantity</b>	<b>Average Age (years)</b>	<b>Expected Service Life (years)</b>
<b>Conductors</b>	352 km	10	90
<b>Steel Towers</b>	710 towers	10	80
<b>Insulators</b>	5,100 strings	10	70

5  
6 **Condition**

7 The asset condition is noted in Table 3. Asset condition assessments are conducted for  
8 each asset as they reach an individual age threshold, which varies depending on asset  
9 type. Condition assessment results are categorized as:

- 10
- **Low Risk:** Assets have condition test results that indicate “like new” or have not yet reached an age where condition assessment is required.
  - **Fair Risk:** Assets have condition test results that indicate minor deterioration but have not yet reached End of Life (“EOL”). These assets will be scheduled for reassessment at a later date, depending on the level of deterioration indicated by the test results.
  - **High Risk:** Assets have condition test results that indicate EOL and in need of replacement within the plan period.
- 11  
12  
13  
14  
15  
16  
17

18  
19 The term EOL is defined as the likelihood of failure, or loss of an asset’s ability to  
20 provide the intended functionality, wherein the failure or loss of functionality would  
21 cause unacceptable consequences. Therefore, while assets may be operating beyond ESL,  
22 they may not be at EOL. At the same time, as the primary driver of replacement  
23 decisions, asset condition will be verified prior to work being undertaken.

**Table 3: Asset Condition Summary**

<b>Asset Type</b>	<b>Quantity</b>	<b>High Risk</b>	<b>Fair Risk</b>	<b>Low Risk</b>
<b>Conductors</b>	352 km	0%	0%	100%
<b>Steel Towers</b>	710 towers	0%	0%	100%
<b>Insulators</b>	5,100 strings	10%	0%	90%

The majority of the assets B2M LP's assets were in-serviced in 2012; therefore, little degradation has occurred, and these assets are considered to have a low condition risk. However, there is a population of insulators on the pre-existing structures that have been determined to be defective, and due to their condition they are considered high risk, as represented in Table 3.

This insulator defect is related to the porcelain insulators manufactured by Canadian Ohio Brass ("COB") and Canadian Porcelain ("CP") between 1965 and 1982 that suffer from a phenomenon known as cement expansion or cement growth. The purpose of the cement is to bond the pin to the porcelain. Cement expansion creates radial cracks in the cement and porcelain shell, resulting in two possible failure modes:

- Mechanical Failure: where the pin separates from the porcelain causing a conductor drop; and/or,
- Electrical Failure: where the cracked porcelain reduces insulating properties.

Insulators suffering from cement expansion are expected to fail prematurely and unpredictably, since failure is influenced by mechanical load and environmental conditions. This topic is discussed extensively in HONI's Transmission Rate Application (EB-2019-0082) in Exhibit B, Tab 1, Schedule 1, TSP Section 2.2.2.4.

The existence of the defective insulators on the small, older portion of B2M LP's line was brought to B2M LP's attention in early 2019. The decision was made at that time to proceed with the repairs, and the work is forecast to be completed in late 2019.

Witness: Donna Jablonsky/Jeffrey Smith

1 **3.2.4 Asset Utilization (*OEB Filing Req. 5.3.2D*)**

2 B2M LP's 500kV double circuit transmission line, circuits B560V and B561M, have a  
3 combined capacity of approximately 3,000 MW. This 500kV double circuit transmission  
4 line is part of the bulk system and is operated in accordance with the planning criteria as  
5 part of the IESO-controlled grid. The adequacy of the bulk system is assessed by the  
6 IESO as part of the bulk system planning processes in accordance with NERC and NPCC  
7 Standards, including the IESO's Ontario Resource Transmission Assessment Criteria  
8 ("ORTAC"). The bulk system is within acceptable capacity levels.

9  
10 **3.3 ASSET LIFECYCLE OPTIMIZATION POLICIES AND PRACTICES**  
11 **(*OEB Filing Req. 5.3.3*)**

12 As documented in Section 3.1, B2M LP works with HONI to undertake a strategic and  
13 methodical asset management process, drawing upon HONI's extensive expertise and  
14 experience to monitor its transmission system assets. HONI has developed and  
15 implemented asset strategies for various components of the transmission system. The  
16 specific strategies related to overhead transmission line assets are outlined in detail in  
17 HONI's Transmission Rate Application (EB-2019-0082) in Exhibit B, Tab 1, Schedule 1,  
18 TSP Section 2.3.2. The following sections provide an overview of the specific operations  
19 and maintenance activities and replacement strategy applicable to B2M LP.

20  
21 **3.3.1 Routine Operation and Maintenance**

22 On behalf of B2M LP, HONI performs routine operation and maintenance of B2M LP's  
23 transmission assets as follows.

24  
25 **Operating Services:**

26 Operating services include the monitoring and control of the transmission system, in  
27 accordance with the requirements of B2M LP's Transmission Licence and all services  
28 required to fulfill all of B2M LP's obligations under its Connection Agreement and the

1 IESO-B2M LP operating requirements. These services include, but are not limited to, the  
2 following:

- 3 • Alarm/asset monitoring, and minor control;
- 4 • Asset operation and switching;
- 5 • Emergency response to transmission system events;
- 6 • Outage processing;
- 7 • Crew dispatching;
- 8 • Record maintenance; and
- 9 • IT Support of the power system applications used by operators.

10  
11 **Maintenance Services:**

12 The maintenance services include all planned and corrective maintenance services of the  
13 transmission line assets and right-of-way, in accordance with the requirements and  
14 obligations of B2M LP's Transmission Licence. Further details are outlined below.

15  
16 *a) Overhead Transmission Lines*

17 On behalf of B2M LP, HONI routinely inspects the overhead transmission lines by  
18 ground and aerial-based patrols to identify safety and reliability defects. HONI also  
19 undertakes emergency repairs and response to restore power or minor corrective work to  
20 resolve reliability and safety problems with transmission line assets when necessary. As  
21 assets age, separate detailed assessments are also performed on individual conductor and  
22 structure assets to monitor condition and determine when replacement is required based  
23 upon assessed condition.

24  
25 *b) Transmission Right-of-Way*

26 The strip of land that is occupied by a transmission line is referred to as a right-of-way or  
27 a corridor. On behalf of B2M LP, HONI performs regular maintenance to maintain  
28 clearance distances between the energized circuits (B560V and B561M) and the

Witness: Donna Jablonsky/Jeffrey Smith

1 vegetation located on and adjacent to the transmission right-of-way. In Southern Ontario,  
 2 vegetation maintenance is performed on clearing cycles of six years. Cycle lengths have  
 3 been set to ensure that rights-of-way are in good condition and maintain a sustainable  
 4 level of reliability between maintenance cycles. B2M LP's transmission line is also  
 5 subject to NERC Standard FAC-003 entitled '*Transmission Vegetation Management*  
 6 *Reliability Standard*', which currently requires B2M LP to report all vegetation-related  
 7 outages on 500kV circuits within B2M LP's control, though natural disasters and human  
 8 activity such as logging are excluded. If vegetation management issues arise mid-cycle,  
 9 HONI would undertake corrective action to resolve reliability and safety problems.

10

11 A summary of the planned maintenance activities and frequency of maintenance can be  
 12 found in Table 4.

13

14

**Table 4: Summary of Planned Maintenance Activities**

<b>Asset</b>	<b>Maintenance</b>	<b>Frequency</b>	<b>Description</b>
<b>Overhead Transmission Lines</b>	Helicopter Patrol	1 year	High speed patrol to identify major defects on overhead transmission line assets.
	Ground Patrol	5 years	More detailed ground based patrol to identify defects on overhead transmission line assets.
	Thermovision	1 year	Identifies defective transmission line components by detecting their heat signature using infrared cameras.
<b>Transmission Right of Way</b>	Line Clearing	6 years	Consists of trimming tree branches and removing any unhealthy trees on the edge of or adjacent to the right-of-way that have the potential to exceed B2M LP's clearances to the overhead transmission lines.
	Brush Control	6 years	Includes manual cutting, herbicide application and/or mechanical clearing to manage vegetation growth on the right-of-way to ensure adequate clearances and access to B2M LP's overhead transmission lines.
	Condition Patrol	6 years	A mid-cycle working inspection to identify and mitigate any vegetation which requires maintenance prior to the next scheduled line clearing or brush control activity.

Asset	Maintenance	Frequency	Description
	Property Owner Notifications	6 years	Prior to the execution of right-of-ways vegetation maintenance, HONI contacts all required adjacent property owners and external stakeholders to communicate maintenance plans.
	Annual Vegetation Patrol	1 year	In accordance with NERC Standard FAC-003, B2M LP is required to annually inspect all 500kV circuits.

1

2 **3.3.2 Asset Replacement**

3 B2M LP’s planned replacement strategy is the same as HONI’s. Assets are replaced  
 4 based on condition assessments. Once an asset condition is determined to be at EOL, it is  
 5 scheduled and prioritized for replacement. In the case of material unplanned capital  
 6 replacement, B2M LP proposes utilizing a z-factor claim approach in accordance with  
 7 Section 2.8.12 of the OEB Filing Requirements, where appropriate.

8

9 **3.4 SYSTEM CAPABILITY ASSESSMENT RENEWABLE ENERGY**  
 10 **GENERATION (*OEB Filing Req. 5.3.4*)**

11 The B2M LP 500kV double circuit transmission line is operated in accordance with the  
 12 planning criteria as part of the IESO-controlled grid based on the load, generation and  
 13 import patterns. The B2M LP circuits, B560V and B561M, continue to allow the transfer  
 14 of committed generating resource and potential to enable new renewable resource in the  
 15 Bruce area. If new generation requests emerge, the assessment of capacity need or  
 16 limitation and its planning would be under the purview of the IESO as part of the bulk  
 17 system planning. At this time, there is no renewable energy generation connection  
 18 forecast affecting B2M LP’s assets.

**4.0 CAPITAL EXPENDITURE PLAN**

This section provides the details of the overall plan that B2M LP plans to undertake over the 2020 to 2024 period, and other pertinent information regarding the elements of the planning process.

**4.1 CAPITAL PLANNING PROCESS OVERVIEW (OEB Filing Req. 5.4.1)**

On behalf of B2M LP, HONI completes an annual investment planning process to establish a plan that appropriately reflects operational needs, while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets, as discussed in Section 3.3 above. B2M LP’s 2020 to 2024 plan is an output of this asset management framework.

**4.2 CAPITAL EXPENDITURE SUMMARY (OEB Filing Req. 5.4.2)**

Table 5 provides a summary of B2M LP’s Overall Plan. B2M LP is not anticipating the need for any planned capital spending over the five-year horizon. B2M LP is forecasting a modest OM&A budget in the test year. Further details are presented in Exhibit F, Tab 2, Schedule 1.

**Table 5: Overall Plan (\$Millions)**  
*OEB Appendix 2-AB*

OEB Category	Historical															Forecast				
	2015			2016			2017			2018			2019		2020	2021	2022	2023	2024	
	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Act	Var	Plan	Frcst	Var	Test	Test	Test	Test	Test
System Access	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Renewal	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	3.0	0.0	0.0	0.0	0.0	0.0
System Service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total Capital</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>3.0</b>	<b>3.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>	<b>0.0</b>
<b>System OM&amp;A</b>	<b>0.9</b>	<b>0.7</b>	<b>-0.2</b>	<b>0.8</b>	<b>0.8</b>	<b>0.0</b>	<b>0.8</b>	<b>1.0</b>	<b>0.3</b>	<b>2.0</b>	<b>1.1</b>	<b>-0.9</b>	<b>0.8</b>	<b>0.7</b>	<b>-0.1</b>	<b>0.7</b>	*	*	*	*

\*System OM&A includes Operations, Maintenance and Administration expenses related to B2M LP’s Service Level Agreement with HONI. System OM&A for 2021 to 2024 is determined based on the escalation factor identified in Exhibit A, Tab 4, Schedule 1

Witness: Donna Jablonsky/Jeffrey Smith

1 There was an unplanned capital expenditure in 2019 to address the defective insulators,  
2 as noted in Section 3.2.3 of this TSP; further details are provided in Exhibit C, Tab 1,  
3 Schedule 1, Attachment 1.

4

5 **4.3 JUSTIFYING CAPITAL EXPENDITURES (*OEB Filing Req. 5.4.3*)**

6 This section (and corresponding OEB Appendix 2-AA) is not applicable, as B2M LP is  
7 not anticipating the need for any planned capital spending over the five-year horizon.

1 **RATE BASE**

2 **1. INTRODUCTION**

3  
4 This Exhibit provides a comparison of 2018 OEB-approved rate base with the 2018  
5 historic year rate base, as well as a forecast of B2M LP's rate base for the 2020 test year  
6 and a detailed description of each of the components.

7  
8 The rate base underlying the revenue requirement for the Test Year includes a forecast of  
9 net utility plant, calculated on a mid-year average basis. No working capital has been  
10 requested, as discussed in section 4 below.

11  
12 **2. COMPARISON OF RATE BASE TO BOARD APPROVED**

13  
14 Table 1 below compares 2018 costs to the 2018 Rate Base approved by the OEB in its  
15 Decision on B2M LP's 2018 revenue requirement application in EB-2017-0380.

16  
17 **Table 1 - 2018 OEB-approved versus 2018 Historic Year Rate Base (\$ Millions)**

<b>Rate Base Component</b>	<b>2018 Actual</b>	<b>2018 OEB-approved</b>	<b>Variance</b>
Mid-Year Gross Plant	547.7	547.7	0.0
Less: Mid-Year Accumulated Depreciation	(46.6)	(45.3)	(1.2)
<b>Mid-Year Net Utility Plant</b>	<b>501.1</b>	<b>502.4</b>	<b>1.2</b>
Cash Working Capital	0.0	0.0	0.0
Materials & Supply Inventory	0.0	0.0	0.0
<b>Total Rate Base</b>	<b>501.1</b>	<b>502.4</b>	<b>1.2</b>

18  
19 Total rate base in 2018 is in line with the OEB-approved total, within 0.3% of the  
20 amount.

Witness: Joel Jodoin

1     **3.    UTILITY RATE BASE**

2  
3     Utility rate base for the Test year is filed at Exhibit C, Tab 2, Schedule 1. The calculation  
4     of Net Utility Plant is provided at Exhibit C, Tab 2, Schedule 2 and 3.

5  
6     B2M LP's forecast rate base for the 2019 Bridge year and 2020 Test year is shown in  
7     Table 2. The mid-year gross plant balance reflects the forecast capital expenditure  
8     programs and in-service additions.

9  
10                     **Table 2 - Transmission Rate Base (\$ Millions)**

<b>Description</b>	<b>Bridge</b>	<b>Test</b>
	<b>2019</b>	<b>2020</b>
Mid-Year Gross Plant	549.2	550.7
Mid-Year Accumulated Depreciation	(53.7)	(60.8)
<b>Mid-Year Net Plant</b>	495.5	489.9
Cash Working Capital	0.0	0.0
Materials and Supply Inventory	0.0	0.0
<b>Transmission Rate Base</b>	495.5	489.9

11  
12     Table 3 below provides historical and bridge year continuity of total fixed assets. The  
13     growth in gross plant reflects the in-service additions made to B2M LP's rate base in  
14     2019, discussed in Exhibit B, Tab 1, Schedule 3, Exhibit B, Tab 1, Schedule 3,  
15     Attachment 1 from Sections 3.2 through 4.3, and the in-service forecast is outlined in  
16     Section 4 below.

1                   **Table 3 - Continuity of Fixed Assets Summary - Rate Base (\$ Millions)**

<b>Description</b>	<b>Historic Years</b>				
	<b>2015</b>	<b>2016</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>
Opening Gross Asset Balance	547.7	547.7	547.7	547.7	547.7
In-Service Additions	0.0	0.0	0.0	0.0	3.0
Retirements	0.0	0.0	0.0	0.0	0.0
Sales	0.0	0.0	0.0	0.0	0.0
Transfers / Other	0.0	0.0	0.0	0.0	0.0
<b>Closing Gross Asset Balance</b>	<b>547.7</b>	<b>547.7</b>	<b>547.7</b>	<b>547.7</b>	<b>550.7</b>

2

3                   **4. CASH WORKING CAPITAL**

4

5                   In 2013, B2M LP retained Navigant Consulting Inc. to undertake a lead-lag study on its  
6                   working capital requirements. The study found that the flows of revenue and expenses  
7                   substantially offset each other, and the resulting in an approximately zero requirement for  
8                   cash working capital. Further details may be found in B2M LP's previous transmission  
9                   rate application (EB-2015-0026) at Exhibit D1, Tab 1, Schedule 2.

10

11                   B2M LP's expenses and revenues continue to be generally synchronized such that no  
12                   working capital has been requested.

13

14                   **5. IN-SERVICE ADDITIONS**

15

16                   In-service additions represent increases to rate base as a result of capital work being  
17                   declared in-service and ready for use.

18

19                   Table 4 provides an overview of B2M LP's in-service additions over the historical 2015  
20                   to 2018 period, the 2019 Bridge year and the 2020 Test Year.

Witness: Joel Jodoin

1  
2

**Table 4 - In-Service Capital Additions 2015 – 2020 (\$ millions)**

	Historical												Bridge			Test
	2015			2016			2017			2018			2019			2020
	Actual	Plan	Var*	Plan												
<b>System Access</b>	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>System Renewal</b>	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0	0.0	3.0	0.0
<b>System Service</b>	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>General Plant</b>	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
<b>Total</b>	<b>0.0</b>	<b>3.0</b>	<b>0.0</b>	<b>3.0</b>	<b>0.0</b>											

3 \*Var: Variance

1 B2M LP incurred no capital expenditures during 2015 to 2018 because no new assets  
2 were placed in service. In 2019, B2M LP had no OEB-approved capital expenditures.  
3 However, to address defective insulators on the older section of its transmission line,  
4 B2M LP expects to place \$3 million of new assets in-service under the System Renewal  
5 category. Further information justifying this unplanned capital expenditure may be found  
6 at Exhibit B, Tab 1, Schedule 3 Sections 3.2 of the TSP.

7

8 B2M LP has no planned capital expenditures or associated in-service additions forecast in  
9 gross plant for the Test Year. Further information regarding capital expenditures may be  
10 found at Exhibit B, Tab 1, Schedule 3 of the TSP.

**B2M LP**  
 Statement of Average Rate Base  
 Bridge Year (2019) and Test Year (2020)  
 Year Ending December 31  
 (\$ Millions)

Line No.	Particulars	2019	2020
	<u>Electric Utility Plant</u>		
1	Gross plant at cost	\$ 550.7	\$ 550.7
2	Less: accumulated depreciation	(57.3)	(64.3)
3	Net plant for rate base	<u>493.4</u>	<u>486.4</u>
4	Average net plant for rate base	495.5	489.9
5	Construction work in progress	0.0	0.0
6	Average net utility plant	\$ <u>495.5</u>	\$ <u>489.9</u>
	<u>Working Capital</u>		
7	Cash working capital	0.0	0.0
8	Materials and Supplies Inventory	0.0	0.0
9	Total working capital	0.0	0.0
10	Total rate base	\$ <u><u>495.5</u></u>	\$ <u><u>489.9</u></u>

**B2M LP**

Continuity of Property, Plant and Equipment - Accumulated Depreciation  
 Historical (2015, 2016, 2017, 2018), Bridge (2019) & Test (2020) Years  
 Year Ending December 31  
 Total - Gross Balances  
 (\$ Millions)

<u>Line No.</u>	<u>Year</u>	<u>Opening Balance</u>	<u>Additions</u>	<u>Retirements</u>	<u>Sales</u>	<u>Transfers In/Out and Other</u>	<u>Closing Balance</u>	<u>Average</u>
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
<u>Historic</u>								
1	2015	21.3	7.2	0.0	0.0	0.3	28.7	25.0
2	2016	28.7	7.2	0.0	0.0	(0.1)	35.8	32.3
3	2017	35.8	7.2	0.0	0.0	0.0	43.0	39.4
4	2018	43.0	7.2	0.0	0.0	0.0	50.1	46.5
<u>Bridge</u>								
5	2019	50.1	7.2	0.0	0.0	0.0	57.3	53.7
<u>Test</u>								
6	2020	57.3	7.0	0.0	0.0	0.0	64.3	60.8

**B2M LP**  
 Continuity of Property, Plant and Equipment  
 Historical (2015 - 2018), Bridge (2019) & Test (2020) Years  
 Year Ending December 31  
 Total - Gross Balances  
 (\$ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
<u>Historic</u>								
1	2015	547.7	0.0	0.0	0.0	0.0	547.7	547.7
2	2016	547.7	0.0	0.0	0.0	0.0	547.7	547.7
3	2017	547.7	0.0	0.0	0.0	0.0	547.7	547.7
4	2018	547.7	0.0	0.0	0.0	0.0	547.7	547.7
<u>Bridge</u>								
5	2019	547.7	3.0	0.0	0.0	0.0	550.7	549.2
<u>Test</u>								
6	2020	550.7	0.0	0.0	0.0	0.0	550.7	550.7

**Appendix 2-BA  
 Fixed Asset Continuity Schedule <sup>1</sup>**

Accounting Standard USGAAP  
 Year 2015

CCA Class <sup>2</sup>	OEB Account <sup>3</sup>	Description <sup>3</sup>	Cost			Accumulated Depreciation				Net Book Value	
			Opening Balance	Additions <sup>4</sup>	Disposals <sup>6</sup>	Closing Balance	Opening Balance	Additions	Disposals <sup>6</sup>		Closing Balance
12	1610	Intangibles	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	
12	1611	Computer Software (Formally known as Account 1925)	\$ -			\$ -	\$ -		\$ -	\$ -	
CEC	1612	Land Rights (Formally known as Account 1906)	\$ -			\$ -	\$ -		\$ -	\$ -	
	1665	Fuel holders, producers and acc.	\$ -			\$ -	\$ -		\$ -	\$ -	
	1675	Generators	\$ -			\$ -	\$ -		\$ -	\$ -	
N/A	1615	Land	\$ -			\$ -	\$ -		\$ -	\$ -	
1	1620	Buildings and fixtures	\$ -			\$ -	\$ -		\$ -	\$ -	
N/A	1705	Land	\$ 12			\$ 12	\$ -		\$ -	\$ 12	
14.1	1706	Land rights	\$ 99			\$ 99	\$ 3	\$ 4	\$ 7	\$ 93	
1	1708	Buildings and fixtures	\$ 0			\$ 0	\$ 0	\$ -	\$ 0	\$ 0	
47	1715	Station equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1720	Towers and fixtures	\$ 281			\$ 281	\$ 11	\$ 7	\$ 0	\$ 278	
47	1730	Overhead conductors and devices	\$ 143			\$ 143	\$ 7	\$ 10		\$ 126	
47	1735	Underground conduit	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1740	Underground conductors and devices	\$ -			\$ -	\$ -		\$ -	\$ -	
17	1745	Roads and trails	\$ 12			\$ 12	\$ 1	\$ 1		\$ 10	
47	1830	Poles, Towers & Fixtures	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1835	Overhead Conductors & Devices	\$ -			\$ -	\$ -		\$ -	\$ -	
N/A	1905	Land	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1908	Buildings & Fixtures	\$ -			\$ -	\$ -		\$ -	\$ -	
13	1910	Leasehold Improvements	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1915	Office Furniture & Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
10	1920	Computer Equipment - Hardware	\$ -			\$ -	\$ -		\$ -	\$ -	
50	1925	Computer software	\$ -			\$ -	\$ -		\$ -	\$ -	
10	1930	Transportation Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1935	Stores Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1940	Tools, Shop & Garage Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1945	Measurement & Testing Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1950	Power Operated Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1955	Communications Equipment	\$ 0			\$ 0	\$ 0		\$ 0	\$ 0	
8	1960	Miscellaneous Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1970	Load Management Controls Customer Premises	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1975	Load Management Controls Utility Premises	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1980	System Supervisor Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1985	Miscellaneous Fixed Assets	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1990	Other Tangible Property	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1995	Contributions & Grants	\$ -			\$ -	\$ -		\$ -	\$ -	
47	2440	Deferred Revenue <sup>6</sup>	\$ -			\$ -	\$ -		\$ -	\$ -	
		<b>Sub-Total</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 21.3</b>	<b>\$ 7.2</b>	<b>\$ 0.3</b>	<b>\$ 28.8</b>	<b>\$ 518.9</b>
		Less Socialized Renewable Energy Generation Investments(input as negative)									
		Less Other Non Rate-Regulated Utility Assets (input as negative)									
		<b>Total PP&amp;E</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 21.3</b>	<b>\$ 7.2</b>	<b>\$ 0.3</b>	<b>\$ 28.8</b>	<b>\$ 518.9</b>
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable									
		<b>Total</b>							<b>\$ 7</b>		

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation  
 Transportation  
 Stores Equipment  
**Net Depreciation** \$ 7

**Notes:**

- Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum, the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
- The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
- The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
- The additions in column (E) must not include construction work in progress (CWIP)
- Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenue
- The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciated expense, and disclose the amount separately.

**Appendix 2-BA  
 Fixed Asset Continuity Schedule <sup>1</sup>**

Accounting Standard USGAAP  
 Year 2016

CCA Class <sup>2</sup>	OEB Account <sup>3</sup>	Description <sup>3</sup>	Cost			Accumulated Depreciation				Net Book Value	
			Opening Balance	Additions <sup>4</sup>	Disposals <sup>6</sup>	Closing Balance	Opening Balance	Additions	Disposals <sup>6</sup>		Closing Balance
12	1610	Intangibles	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	
12	1611	Computer Software (Formally known as Account 1925)	\$ -			\$ -	\$ -		\$ -	\$ -	
CEC	1612	Land Rights (Formally known as Account 1906)	\$ -			\$ -	\$ -		\$ -	\$ -	
	1665	Fuel holders, producers and acc.	\$ -			\$ -	\$ -		\$ -	\$ -	
	1675	Generators	\$ -			\$ -	\$ -		\$ -	\$ -	
N/A	1615	Land	\$ -			\$ -	\$ -		\$ -	\$ -	
1	1620	Buildings and fixtures	\$ -			\$ -	\$ -		\$ -	\$ -	
N/A	1705	Land	\$ 12			\$ 12	\$ -		\$ -	\$ 12	
14.1	1706	Land rights	\$ 99			\$ 99	\$ 7	\$ 1	\$ 8	\$ 92	
1	1708	Buildings and fixtures	\$ 0			\$ 0	\$ 0	\$ 0	\$ 0	\$ 0	
47	1715	Station equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1720	Towers and fixtures	\$ 281			\$ 281	\$ 4	\$ 4	\$ 0	\$ 274	
47	1730	Overhead conductors and devices	\$ 143			\$ 143	\$ 17	\$ 2		\$ 124	
47	1735	Underground conduit	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1740	Underground conductors and devices	\$ -			\$ -	\$ -		\$ -	\$ -	
17	1745	Roads and trails	\$ 12			\$ 12	\$ 2	\$ 0		\$ 10	
47	1830	Poles, Towers & Fixtures	\$ -			\$ -	\$ -		\$ -	\$ -	
N/A	1905	Land	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1908	Buildings & Fixtures	\$ -			\$ -	\$ -		\$ -	\$ -	
13	1910	Leasehold Improvements	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1915	Office Furniture & Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
10	1920	Computer Equipment - Hardware	\$ -			\$ -	\$ -		\$ -	\$ -	
50	1925	Computer software	\$ -			\$ -	\$ -		\$ -	\$ -	
10	1930	Transportation Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1935	Stores Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1940	Tools, Shop & Garage Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1945	Measurement & Testing Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1950	Power Operated Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1955	Communications Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
8	1960	Miscellaneous Equipment	\$ 0			\$ 0	\$ 0	\$ -	\$ 0	\$ 0	
47	1970	Load Management Controls Customer Premises	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1975	Load Management Controls Utility Premises	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1980	System Supervisor Equipment	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1985	Miscellaneous Fixed Assets	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1990	Other Tangible Property	\$ -			\$ -	\$ -		\$ -	\$ -	
47	1995	Contributions & Grants	\$ -			\$ -	\$ -		\$ -	\$ -	
47	2440	Deferred Revenue <sup>5</sup>	\$ -			\$ -	\$ -		\$ -	\$ -	
		<b>Sub-Total</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 28.8</b>	<b>\$ 7.2</b>	<b>\$ 0.1</b>	<b>\$ 35.8</b>	<b>\$ 511.9</b>
		Less Socialized Renewable Energy Generation Investments(input as negative)								\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)								\$ -	\$ -
		<b>Total PP&amp;E</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 28.8</b>	<b>\$ 7.2</b>	<b>\$ 0.1</b>	<b>\$ 35.8</b>	<b>\$ 511.9</b>
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable									
		<b>Total</b>					<b>\$ 7</b>				

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation  
 Transportation  
 Stores Equipment  
**Net Depreciation** \$ 7

**Notes:**

- Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum, the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
- The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
- The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
- The additions in column (E) must not include construction work in progress (CWIP)
- Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenue
- The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciated expense, and disclose the amount separately.

Appendix 2-BA  
 Fixed Asset Continuity Schedule <sup>1</sup>

Accounting Standard USGAAP  
 Year 2017

CCA Class <sup>2</sup>	OEB Account <sup>3</sup>	Description <sup>3</sup>	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions <sup>4</sup>	Disposals <sup>6</sup>	Closing Balance	Opening Balance	Additions	Disposals <sup>6</sup>	Closing Balance	
12	1610	Intangibles	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
12	1611	Computer Software (Formally known as Account 1925)	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CEC	1612	Land Rights (Formally known as Account 1906)	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
6	1665	Fuel holders, producers and acc.	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	1675	Generators	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
N/A	1615	Land	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
1	1620	Buildings and fixtures	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
N/A	1705	Land	\$ 12			\$ 12	\$ -	\$ -	\$ -	\$ -	\$ 12
14.1	1706	Land rights	\$ 99			\$ 99	\$ 8	\$ 1	\$ 9	\$ -	\$ 91
1	1708	Buildings and fixtures	\$ 0			\$ 0	\$ 0	\$ 0	\$ 0	\$ -	\$ 0
47	1715	Station equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1720	Towers and fixtures	\$ 281			\$ 281	\$ 7	\$ 4	\$ 11	\$ -	\$ 270
47	1730	Overhead conductors and devices	\$ 143			\$ 143	\$ 19	\$ 2	\$ 21	\$ -	\$ 122
47	1735	Underground conduit	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1740	Underground conductors and devices	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	1745	Roads and trails	\$ 12			\$ 12	\$ 2	\$ 0	\$ 2	\$ -	\$ 9
47	1830	Poles, Towers & Fixtures	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
N/A	1905	Land	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1908	Buildings & Fixtures	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
13	1910	Leasehold Improvements	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1915	Office Furniture & Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	1920	Computer Equipment - Hardware	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
50	1925	Computer software	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	1930	Transportation Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1935	Stores Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1940	Tools, Shop & Garage Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1945	Measurement & Testing Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1950	Power Operated Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1955	Communications Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1960	Miscellaneous Equipment	\$ 0			\$ 0	\$ 0	\$ -	\$ 0	\$ -	\$ 0
47	1970	Load Management Controls Customer Premises	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1975	Load Management Controls Utility Premises	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1980	System Supervisor Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1985	Miscellaneous Fixed Assets	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1990	Other Tangible Property	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1995	Contributions & Grants	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	2440	Deferred Revenue <sup>5</sup>	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
		<b>Sub-Total</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 35.8</b>	<b>\$ 7.2</b>	<b>\$ -</b>	<b>\$ 43.0</b>	<b>\$ 504.7</b>
		Less Socialized Renewable Energy Generation Investments(input as negative)								\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)								\$ -	\$ -
		<b>Total PP&amp;E</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 35.8</b>	<b>\$ 7.2</b>	<b>\$ -</b>	<b>\$ 43.0</b>	<b>\$ 504.7</b>
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable									
		<b>Total</b>								<b>7</b>	

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation  
 Transportation  
 Stores Equipment  
**Net Depreciation** \$ 7

Notes:

- Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum, the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
- The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
- The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
- The additions in column (E) must not include construction work in progress (CWIP)
- Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenue
- The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciated expense, and disclose the amount separately.

**Appendix 2-BA  
 Fixed Asset Continuity Schedule <sup>1</sup>**

Accounting Standard USGAAP  
 Year 2018

CCA Class <sup>2</sup>	OEB Account <sup>3</sup>	Description <sup>3</sup>	Cost			Accumulated Depreciation					
			Opening Balance	Additions <sup>4</sup>	Disposals <sup>6</sup>	Closing Balance	Opening Balance	Additions	Disposals <sup>6</sup>	Closing Balance	Net Book Value
12	1610	Intangibles	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
12	1611	Computer Software (Formally known as Account 1925)	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
CEC	1612	Land Rights (Formally known as Account 1906)	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1665	Fuel holders, producers and acc.	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1675	Generators	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
N/A	1615	Land	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
1	1620	Buildings and fixtures	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
N/A	1705	Land	\$ 12			\$ 12	\$ -	\$ -	\$ -	\$ -	\$ 12
14.1	1706	Land rights	\$ 99			\$ 99	\$ 9	\$ 1	\$ 10	\$ -	\$ 90
1	1708	Buildings and fixtures	\$ 0			\$ 0	\$ 0	\$ 0	\$ 0	\$ -	\$ 0
47	1715	Station equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1720	Towers and fixtures	\$ 281			\$ 281	\$ 11	\$ 4	\$ 15	\$ -	\$ 267
47	1730	Overhead conductors and devices	\$ 143			\$ 143	\$ 21	\$ 2	\$ 23	\$ -	\$ 120
47	1735	Underground conduit	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1740	Underground conductors and devices	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
17	1745	Roads and trails	\$ 12			\$ 12	\$ 2	\$ 0	\$ 2	\$ -	\$ 9
N/A	1905	Land	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1908	Buildings & Fixtures	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
13	1910	Leasehold Improvements	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1915	Office Furniture & Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	1920	Computer Equipment - Hardware	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
	1925	Computer software	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
10	1930	Transportation Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1935	Stores Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1940	Tools, Shop & Garage Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1945	Measurement & Testing Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1950	Power Operated Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1955	Communications Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
8	1960	Miscellaneous Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1970	Load Management Controls Customer Premises	\$ 0			\$ 0	\$ 0	\$ -	\$ 0	\$ -	\$ 0
47	1975	Load Management Controls Utility Premises	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1980	System Supervisor Equipment	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1985	Miscellaneous Fixed Assets	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1990	Other Tangible Property	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	1995	Contributions & Grants	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
47	2440	Deferred Revenue <sup>5</sup>	\$ -			\$ -	\$ -	\$ -	\$ -	\$ -	\$ -
		<b>Sub-Total</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 43.0</b>	<b>\$ 7.2</b>	<b>\$ 0.0</b>	<b>\$ 50.1</b>	<b>\$ 498</b>
		Less Socialized Renewable Energy Generation Investments(input as negative)				\$ -				\$ -	\$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				\$ -				\$ -	\$ -
		<b>Total PP&amp;E</b>	<b>\$ 547.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 547.7</b>	<b>\$ 43.0</b>	<b>\$ 7.2</b>	<b>\$ 0.0</b>	<b>\$ 50.1</b>	<b>\$ 498</b>
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable									
		<b>Total</b>								<b>7</b>	

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation  
 Transportation  
 Stores Equipment  
**Net Depreciation** \$ 7

**Notes:**

- Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum, the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
- The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
- The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
- The additions in column (E) must not include construction work in progress (CWIP)
- Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenue
- The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA  
 Fixed Asset Continuity Schedule <sup>1</sup>

Accounting Standard USGAAP  
 Year 2019

CCA Class <sup>2</sup>	OEB Account <sup>3</sup>	Description <sup>3</sup>	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions <sup>4</sup>	Disposals <sup>6</sup>	Closing Balance	Opening Balance	Additions	Disposals <sup>6</sup>	Closing Balance	
12	1610	Intangibles	\$ -			\$ -	\$ -			\$ -	\$ -
12	1611	Computer Software (Formally known as Account 1925)	\$ -			\$ -	\$ -			\$ -	\$ -
CEC	1612	Land Rights (Formally known as Account 1906)	\$ -			\$ -	\$ -			\$ -	\$ -
	1665	Fuel holders, producers and acc.	\$ -			\$ -	\$ -			\$ -	\$ -
	1675	Generators	\$ -			\$ -	\$ -			\$ -	\$ -
N/A	1615	Land	\$ -			\$ -	\$ -			\$ -	\$ -
1	1620	Buildings and fixtures	\$ -			\$ -	\$ -			\$ -	\$ -
N/A	1705	Land	\$ 12	\$ -		\$ 12	\$ -	\$ -		\$ -	\$ 12
14.1	1706	Land rights	\$ 99	\$ -		\$ 99	\$ 10	\$ 1		\$ 10.6	\$ 89
1	1708	Buildings and fixtures	\$ 0	\$ -		\$ 0	\$ 0	\$ 0		\$ 0.0	\$ 0
47	1715	Station equipment	\$ -			\$ -	\$ -			\$ -	\$ -
47	1720	Towers and fixtures	\$ 281	\$ -		\$ 281	\$ 15	\$ 4		\$ 18.5	\$ 263
47	1730	Overhead conductors and devices	\$ 143	\$ 3		\$ 146	\$ 23	\$ 2		\$ 25.5	\$ 121
47	1735	Underground conduit	\$ -			\$ -	\$ -			\$ -	\$ -
47	1740	Underground conductors and devices	\$ -			\$ -	\$ -			\$ -	\$ -
17	1745	Roads and trails	\$ 12	\$ -		\$ 12	\$ 2	\$ 0		\$ 2.7	\$ 9
N/A	1905	Land	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
47	1908	Buildings & Fixtures	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
13	1910	Leasehold Improvements	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1915	Office Furniture & Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
10	1920	Computer Equipment - Hardware	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
	1925	Computer software	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
10	1930	Transportation Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1935	Stores Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1940	Tools, Shop & Garage Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1945	Measurement & Testing Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1950	Power Operated Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1955	Communications Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
8	1960	Miscellaneous Equipment	\$ -	\$ -		\$ -	\$ -			\$ -	\$ -
47	1970	Load Management Controls Customer Premises	\$ 0	\$ -		\$ 0	\$ 0	\$ 0		\$ 0.0	\$ 0
47	1975	Load Management Controls Utility Premises	\$ -			\$ -	\$ -			\$ -	\$ -
47	1980	System Supervisor Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
47	1985	Miscellaneous Fixed Assets	\$ -			\$ -	\$ -			\$ -	\$ -
47	1990	Other Tangible Property	\$ -			\$ -	\$ -			\$ -	\$ -
47	1995	Contributions & Grants	\$ -			\$ -	\$ -			\$ -	\$ -
47	2440	Deferred Revenue <sup>5</sup>	\$ -			\$ -	\$ -			\$ -	\$ -
		<b>Sub-Total</b>	<b>\$ 547.7</b>	<b>\$ 3.0</b>	<b>\$ -</b>	<b>\$ 550.7</b>	<b>\$ 50.1</b>	<b>\$ 7.2</b>	<b>\$ -</b>	<b>\$ 57.3</b>	<b>\$ 493</b>
		<b>Less Socialized Renewable Energy Generation Investments (input as negative)</b>				\$ -				\$ -	\$ -
		<b>Less Other Non Rate-Regulated Utility Assets (input as negative)</b>	\$ -			\$ -	\$ -			\$ -	\$ -
		<b>Total PP&amp;E</b>	<b>\$ 547.7</b>	<b>\$ 3.0</b>	<b>\$ -</b>	<b>\$ 550.7</b>	<b>\$ 50.1</b>	<b>\$ 7.2</b>	<b>\$ -</b>	<b>\$ 57.3</b>	<b>\$ 493</b>
		<b>Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable<sup>6</sup></b>									
		<b>Total</b>					<b>\$ 7</b>				

10	Transportation
8	Stores Equipment

Less: Fully Allocated Depreciation:  
 Transportation  
 Stores Equipment  
**Net Depreciation** \$ 7

Notes:

- Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum, the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
- The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
- The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
- The additions in column (E) must not include construction work in progress (CWIP).
- Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
- The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

**Appendix 2-BA  
 Fixed Asset Continuity Schedule <sup>1</sup>**

Accounting Standard USGAAP  
 Year 2020

CCA Class <sup>2</sup>	OEB Account <sup>3</sup>	Description <sup>3</sup>	Cost				Accumulated Depreciation				Net Book Value
			Opening Balance	Additions <sup>4</sup>	Disposals <sup>5</sup>	Closing Balance	Opening Balance	Additions	Disposals <sup>6</sup>	Closing Balance	
12	1610	Intangibles	\$ -			\$ -	\$ -			\$ -	\$ -
12	1611	Computer Software (Formally known as Account 1925)	\$ -			\$ -	\$ -			\$ -	\$ -
CEC	1612	Land Rights (Formally known as Account 1906)	\$ -			\$ -	\$ -			\$ -	\$ -
	1665	Fuel holders, producers and acc.	\$ -			\$ -	\$ -			\$ -	\$ -
	1675	Generators	\$ -			\$ -	\$ -			\$ -	\$ -
N/A	1615	Land	\$ -			\$ -	\$ -			\$ -	\$ -
1	1620	Buildings and fixtures	\$ -			\$ -	\$ -			\$ -	\$ -
N/A	1705	Land	\$ 12			\$ 12	\$ -	\$ 0		\$ 0	\$ 12
14.1	1706	Land rights	\$ 99			\$ 99	\$ 11	\$ 1		\$ 12	\$ 88
1	1708	Buildings and fixtures	\$ 0			\$ 0	\$ 0	\$ 0		\$ 0	\$ 0
47	1715	Station equipment	\$ -			\$ -	\$ -			\$ -	\$ -
47	1720	Towers and fixtures	\$ 281			\$ 281	\$ 19	\$ 4		\$ 22	\$ 259
47	1730	Overhead conductors and devices	\$ 146			\$ 146	\$ 26	\$ 2		\$ 28	\$ 118
47	1735	Underground conduit	\$ -			\$ -	\$ -			\$ -	\$ -
47	1740	Underground conductors and devices	\$ -			\$ -	\$ -			\$ -	\$ -
17	1745	Roads and trails	\$ 12			\$ 12	\$ 3	\$ 0		\$ 3	\$ 9
N/A	1905	Land	\$ -			\$ -	\$ -			\$ -	\$ -
47	1908	Buildings & Fixtures	\$ -			\$ -	\$ -			\$ -	\$ -
13	1910	Leasehold Improvements	\$ -			\$ -	\$ -			\$ -	\$ -
8	1915	Office Furniture & Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
10	1920	Computer Equipment - Hardware	\$ -			\$ -	\$ -			\$ -	\$ -
	1925	Computer software	\$ -			\$ -	\$ -			\$ -	\$ -
10	1930	Transportation Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
8	1935	Stores Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
8	1940	Tools, Shop & Garage Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
8	1945	Measurement & Testing Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
8	1950	Power Operated Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
8	1955	Communications Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
8	1960	Miscellaneous Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
47	1970	Load Management Controls Customer Premises	\$ 0			\$ 0	\$ 0	\$ 0		\$ 0	\$ 0
47	1975	Load Management Controls Utility Premises	\$ -			\$ -	\$ -			\$ -	\$ -
47	1980	System Supervisor Equipment	\$ -			\$ -	\$ -			\$ -	\$ -
47	1985	Miscellaneous Fixed Assets	\$ -			\$ -	\$ -			\$ -	\$ -
47	1990	Other Tangible Property	\$ -			\$ -	\$ -			\$ -	\$ -
47	1995	Contributions & Grants	\$ -			\$ -	\$ -			\$ -	\$ -
47	2440	Deferred Revenues	\$ -			\$ -	\$ -			\$ -	\$ -
		<b>Sub-Total</b>	<b>\$ 550.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 550.7</b>	<b>\$ 57.3</b>	<b>\$ 7.0</b>	<b>\$ -</b>	<b>\$ 64.3</b>	<b>\$ 486</b>
		<b>Less Socialized Renewable Energy Generation Investments (input as negative)</b>				\$ -				\$ -	\$ -
		<b>Less Other Non Rate-Regulated Utility Assets (input as negative)</b>	\$ -			\$ -	\$ -			\$ -	\$ -
		<b>Total PP&amp;E</b>	<b>\$ 550.7</b>	<b>\$ -</b>	<b>\$ -</b>	<b>\$ 550.7</b>	<b>\$ 57.3</b>	<b>\$ 6.99</b>	<b>\$ -</b>	<b>\$ 64.3</b>	<b>\$ 486</b>
		<b>Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable<sup>6</sup></b>									
		<b>Total</b>					<b>\$ 7</b>				

10	Transportation
8	Stores Equipment

**Less: Fully Allocated Depreciation**  
 Transportation             
 Stores Equipment             
**Net Depreciation** \$ 7

**Notes:**

- Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum, the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
- The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
- The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
- The additions in column (E) must not include construction work in progress (CWIP).
- Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
- The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

1 **PERFORMANCE MEASURES**

2  
3 **1. INTRODUCTION**

4  
5 In the B2M LP Transmission Cost of Service Application (EB-2015-0026); B2M LP  
6 proposed the tracking and annual reporting of four outcome measures:

- 7 • System Average Interruption Frequency;  
8 • System Average Interruption Duration;  
9 • Average System Availability; and  
10 • NERC Vegetation Compliance.

11  
12 In the Decision and Order, the OEB approved B2M LP's proposal and directed B2M LP  
13 to also report annually on the operations, maintenance and administration cost per  
14 kilometre of line as a measure to track B2M LP's continuous improvement in cost  
15 efficiency. The Decision and Order also stated that the OEB did not require B2M LP to  
16 file a draft scorecard at that time.<sup>1</sup>

17  
18 Given the nature of B2M LP's assets, the performance of the equipment does not lend  
19 itself to applying the typical measures that might be in place for other transmitters. B2M  
20 LP's assets consist solely of a single 500kV double circuit transmission line (circuits  
21 B560M and B561V) between the Bruce Nuclear Power Development and the Milton  
22 Switching Station, but does not include any terminal breakers or other operable assets, as  
23 the demarcation point of each of the circuits is at a tower outside of the station, as noted  
24 in Exhibit B, Tab 1, Schedule 1. B2M LP does not have any customer delivery points (or  
25 meter assets), which are the basis of interruption-based reliability performance measures

---

<sup>1</sup> Decision and Order in Proceeding EB-2015-0026, page 11.

Witness: Jeffrey Smith

1 like SAIDI and SAIFI. In addition to these operating characteristics, the life-cycle  
2 portfolio also detracts from meaningful comparisons. B2M LP's single transmission line  
3 is relatively new; whereas other transmitters own a portfolio of assets that traverse the  
4 various stages of asset life.

5  
6 Therefore, B2M LP's performance measures do not readily provide meaningful  
7 comparisons to those of other transmitters. On this basis, B2M LP proposes that System  
8 Average Interruption Frequency and System Average Interruption Duration no longer be  
9 measured. Furthermore, B2M LP has no customers, so no Customer Focus measures have  
10 been proposed.

## 11 12 **2. PERFORMANCE MEASURES**

13  
14 B2M LP is proposing to continue to track its performance by utilizing most of the  
15 measures approved by the Board in proceeding EB-2015-0026 to ensure that B2M LP is  
16 meeting its five-year plan as described in this Application. The performance measures  
17 will be tracked annually, and the results of this tracking will be reported to the Board at  
18 the next proceeding. B2M LP has aligned its performance measures to the OEB's  
19 Renewed Regulatory Framework ("RRF") outcomes to ensure that B2M LP is  
20 monitoring and measuring performance relative to these outcomes.

21  
22 Table 1 provides a summary of the results for the years 2015 to 2018 and the proposed  
23 targets for the years 2019 and 2020.

1

**Table 1 - B2M LP Performance Measures**

RRF Outcomes	Performance Measure	Actual Results				Forecast	
		2015	2016	2017	2018	2019	2020
Operational Excellence	Average System Availability (%)	99.04	99.12	100.0	100.0	100.0	100.0
Operational Excellence	System Average Interruption Frequency*	-	-	-	-	-	N/A
Operational Excellence	System Average Interruption Duration*	-	-	-	-	-	N/A
Public Policy Responsiveness	NERC Vegetation Compliance	Comply	Comply	Comply	Comply	Comply	Comply
Operational Excellence	OM&A Cost (\$K) per circuit kilometre	3.1	3.1	3.8	4.0	3.8	3.3
Financial Performance	Return on Equity (%)	9.9	9.2	8.9	10.3	8.98	8.98

2 \* These measures consider interruptions at a delivery point. B2M LP does not have any delivery points; and while the  
 3 line was unavailable for very brief periods of time, no delivery points or customers were interrupted because of B2M  
 4 LP's assets.

5

6 In all cases, these measures verify that the assets are operating within expected  
 7 parameters and continue to serve the electricity consumers of Ontario successfully.

8

9 The variations in the B2M LP OM&A expenses are mainly a result of the cyclical  
 10 vegetation management program required for compliance with NERC standards. Other  
 11 than these forestry expenses, the overall operating and maintenance expenses remain well  
 12 below what would otherwise be expected of an average circuit. However, given the  
 13 limited operational scope of the B2M LP assets, the cost comparisons may not be a fair  
 14 comparison to the average costs of other transmitters. The comparison may suggest that  
 15 other transmitters are higher cost, when in fact this may be due primarily to the broader  
 16 set of assets in place.

Witness: Jeffrey Smith

1 **Appendix A – Description of the Performance Measures**

2  
3 **Average System Availability**

4 “System Availability” is a measure of the extent to which the transmission line(s) are  
5 available for use within the system. For the purposes of quantifying this metric, the cause  
6 of the forced outages that would contribute to the unavailability of the transmission lines  
7 (B560V and B561M) would be limited to factors affecting  
8 assets owned by B2M LP as opposed to terminal equipment,  
9 owned by Hydro One, which could also cause the transmission  
10 line(s) to be removed from service.

$$\left[ 1 - \frac{\sum_{i=1}^{N_L} F_{L_i}}{T_L} \right] \times 100\%$$

- 11 •  $F_{L_i}$  is the annual forced outage duration in hours due to transmission line-related  
12 outages of circuit  $L_i$ .
- 13 •  $T_L$  is the inventory (expressed in 100 km-hours) of all in-service transmission  
14 circuits.
- 15 •  $N_L$  is the total number of in-service transmission circuits

16  
17 **NERC Vegetation Compliance**

18 NERC Vegetation Compliance is a measure of the extent to which B2M LP is compliant  
19 with NERC’s Standard FAC-003-02 ‘Transmission Vegetation Management’. NERC  
20 developed a Transmission Vegetation Management Standard with the objective to  
21 prevent vegetation-related outages which could contribute to a cascading grid failure,  
22 especially under heavy electrical loading conditions. Each transmission owner is  
23 required to have a transmission vegetation management program designed to control  
24 vegetation on the active transmission line right-of-way in accordance with the  
25 requirements in NERC Standard FAC-003-02. Compliance with the Standard is  
26 mandatory and enforceable.

1 **Return on Equity**

2 Return on Equity compares the profitability of the Applicant over a period compared to  
3 the amount of equity invested by the partners. The biggest impact on ROE for B2M LP is  
4 related to revenue variances caused generally by changes in weather compared to budget.

5

6 Using the Audited Statements, the ROE is calculated by dividing the Net Income (less  
7 extraordinary non-operating items such as startup cost reimbursement) by the Partners'  
8 Equity.

## REVENUE REQUIREMENT

### 1. SUMMARY OF REVENUE REQUIREMENT

B2M LP follows standard regulatory practice and has calculated its revenue requirement as follows:

**Table 1 - Revenue Requirement (\$ Millions)**

Components	2019 <sup>1</sup>	2020	Reference
OM&A	1.5	1.2	Exhibit F, Tab 1, Schedule 1
Depreciation	6.8	7.0	Exhibit F, Tab 5, Schedule 1
Income Taxes	0.8	1.0	Exhibit F, Tab 6, Schedule 1, Attachment 1
Return on Capital	23.4	26.6	Exhibit G, Tab 1, Schedule 1
Start-Up and Development Costs Recovery	1.9	0.0	Exhibit F, Tab 1, Schedule 1
<b>Base Revenue Requirement</b>	<b>34.4</b>	<b>35.7</b>	
Deduct External Revenues and Other <sup>2</sup>	(1.6)	(0.1)	Exhibit H, Tab 1, Schedule 1
<b>Rates Revenue Requirement</b>	<b>32.8</b>	<b>35.7</b>	

*Note 1: OEB approved 2019 revenue requirement in EB-2018-0320.*

*Note 2: EB-2017-0380, the Decision issued on May 3, 2018 found 2018 Excess Revenue equivalent to \$1.6 million and ordered that the 2018 UTRs stay at their current level and that the 2018 Excess Revenue for B2M LP be included in 2019 Revenue Requirement calculations.*

The above Revenue Requirement is the amount required by B2M LP to achieve its business objectives, responsible stewardship of a safe and reliable system, and impact on rates. The proposed Revenue Requirement is a reflection B2M LP's commitment to operating at the lowest practical cost.

### 2. CALCULATION OF REVENUE REQUIREMENT

The details of the Revenue Requirement components are as follows:

Witness: Joel Jodoin

1 **2.1 OM&A EXPENSE**

2  
3 **Table 2 - OM&A Expense (\$ Millions)\***

	<b>2020</b>
Service Level Agreement Costs	0.7
Incremental Expenses	0.4
<b>Total OM&amp;A</b>	<b>1.2</b>

4 \* Exhibit F, Tab 2, Schedule 1

5  
6 **2.2 DEPRECIATION AND AMORTIZATION EXPENSE**

7  
8 **Table 3 - Depreciation and Amortization Expense (\$ Millions)\***

	<b>2020</b>
Depreciation	7.0
<b>Total Expense</b>	<b>7.0</b>

9 \*Exhibit F, Tab 5, Schedule 1

10  
11 **2.3 CORPORATE INCOME TAXES**

12  
13 **Table 4 - Corporate Income Taxes (\$ Millions)\***

	<b>2020</b>
Regulatory Taxable Income	4.3
Tax Rate	26.5%
<b>Subtotal</b>	<b>1.1</b>
Less: Credits	(0.2)
<b>Total Income Taxes</b>	<b>1.0</b>

14 \* Exhibit F, Tab 6, Schedule 1

1 **2.4 RETURN ON CAPITAL**

2  
 3 **Table 5 - Return on Capital (\$ Millions)\***

	<b>2020</b>
Return on Debt	9.0
Return on Equity	17.6
<b>Return on Capital</b>	<b>26.6</b>

4 \*Exhibit G, Tab 1, Schedule 1

5  
 6 **3. REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON**

7  
 8 Table 6 below provides a summary of the value of the key impacts compared to the 2019  
 9 Bridge year’s approved Base Revenue Requirement (as per EB-2018-0320) with the 2020  
 10 Test Year’s proposed Base Revenue Requirement. 2019 is used as it represents the last  
 11 rebasing year for B2M LP.

12  
 13 **Table 6 - Impact of the Individual Component on Base Revenue Requirement**

Description	2020 vs. 2019 (\$ millions)	2020 vs. 2019 (%)
OM&A	(0.3)	-1.0%
Rate Base	(0.1)	-0.3%
Cost of debt	3.6	10.4%
Tax	0.2	0.5%
Start-Up and Development Costs Recovery	(1.9)	-5.9%
<b>Impact on Base Revenue Requirement</b>	<b>1.3</b>	<b>3.9%</b>

14  
 15 **Revenue Requirement: 2020 vs. 2019 (\$ Millions)**

16 The increase in base revenue requirement is driven predominantly by higher cost of debt,  
 17 given the maturity of B2M LP’s previous five-year long-term debt (\$3.6 million), offset  
 18 by the expiry of the recovery of start-up costs.

Witness: Joel Jodoin

**B2M LP**  
Calculation of Revenue Requirement (2020)  
Year Ending December 31  
(\$ Millions)

Line No.	Particulars	Test 2020 (a)
	Cost of Service	
1	Operating, maintenance & administrative	\$ 1.2
2	Depreciation	7.0
3	Income taxes	1.0
4	Cost of service excluding return on capital	\$ <u>9.1</u>
5	Return on capital	26.6
6	Base revenue requirement	\$ <u><u>35.7</u></u>

## OPERATING COSTS SUMMARY

### 1. INTRODUCTION

This Exhibit presents an overview of B2M LP's operating costs and includes the following elements, for which the overall costs are shown in Table 1 below:

- Operation, Maintenance and Administrative ("OM&A"),
- Depreciation and Amortization, and
- Income Taxes.

**Table 1 - Operating Costs (\$ Millions)**

Description	Historical Years				Bridge Year	Test Year
	2015	2016	2017	2018	2019	2020
OM&A	1.1	1.1	1.3	1.4	1.3	1.2
Depreciation and Amortization	7.2	7.2	7.2	7.2	7.2	7.0
Income Taxes	0.6	0.3	0.3	0.7	1.1	1.0
<b>Total Operating Costs<sup>1</sup></b>	<b>8.9</b>	<b>8.6</b>	<b>8.8</b>	<b>9.3</b>	<b>9.6</b>	<b>9.2</b>

The proposed operating costs for the 2020 Test Year is forecast to be \$9.2 million, a reduction of \$0.4 million compared to the 2019 Bridge year forecast. This decrease is due to slightly lower OM&A and Depreciation expenses, as documented in Exhibit F, Tab 2, Schedule 1 and Exhibit F, Tab 5, Schedule 1, respectively.

<sup>1</sup> In addition to these total operating costs, the Decision and Order in proceeding EB-2015-0026 allowed the \$7.7 million start-up cost to be recovered in rates over a four-year period, with \$1.925 million being recovered each year from 2016 to 2019.

Witness: Joel Jodoin

1    **2.    KEY ELEMENTS OF OPERATING COSTS**

2  
3    B2M LP’s operating costs forecast has been developed to sustain the safe and reliable  
4    operation of its transmission assets.

5  
6    **2.1   OPERATION, MAINTENANCE AND ADMINISTRATIVE (“OM&A”)**

7  
8    B2M LP is managed by its general partner, Hydro One Indigenous Partnerships GP Inc.  
9    (“HOIP GP”), formerly named B2M GP Inc., which retains Hydro One Networks  
10    (“HONI”), under a Service Level Agreement, to plan and organize the operation and  
11    maintenance of the assets and provide certain corporate and administrative support as  
12    outlined in Exhibit F, Tab 3, Schedule 1.

13  
14    OM&A expenses are derived based upon the various work programs and functions  
15    performed by or on behalf of the Partnership. The estimated total OM&A expense is  
16    \$1.2 million in 2020. Further details on the OM&A costs are provided in Exhibit F, Tab  
17    2, Schedule 1.

18  
19    **2.2   DEPRECIATION AND AMORTIZATION**

20  
21    The depreciation expense for B2M LP in this Application is supported by  
22    recommendations that Foster Associates Inc. made on the appropriate depreciation rates  
23    for HONI Transmission in support of its 2020 to 2022 Rate Application (EB-2019-0082).  
24    Supporting evidence for this study is filed at Exhibit F, Tab 5, Schedule 1, Attachment 1.  
25    This methodology is consistent with that approved for use by B2M LP and HONI  
26    Transmission in previous proceedings. The estimated depreciation expense is \$7.0  
27    million in 2020. Further details are provided in Exhibit F, Tab 5, Schedule 1.

Witness: Joel Jodoin

1 **2.3 INCOME TAXES**

2

3 Under the *Income Tax Act*, a partnership is not taxable but is required to compute its  
4 taxable income, which is then allocated to its partners. The estimated Income Tax  
5 expense that will be required to be paid by the partners from the income generated in  
6 B2M LP is \$1.0 million in 2020. These amounts reflect the non-taxable status of  
7 Saugeen Ojibway Nation Finance Corporation (“SON FC”). Details of the calculation of  
8 the Income Tax expense are shown in Exhibit F, Tab 6, Schedule 1.

**SUMMARY OF OM&A EXPENDITURES**

**1. SUMMARY OF OM&A EXPENDITURES**

The proposed Operation, Maintenance, and Administration (“OM&A”) expenses represent the work required to meet public and employee safety objectives, maintain transmission reliability, and to comply with regulatory requirements, environmental requirements and Government direction. Key components in the build-up of OM&A requirements are:

- Service Level Agreement with Hydro One Networks (“HONI”), and
- Ongoing Incremental Expenses of the Partnership

Table 1 presents the required funding for OM&A in the 2020 Test Year, along with the actual and planned spending levels for the bridge and historical years, for each of these key components. Overall, B2M LP OM&A spending on a per asset basis is low in comparison to other transmitters in Ontario. This relates primarily to the characteristics of the assets that it owns. B2M LP owns a 500kV double-circuit transmission line that is parallel to an existing 500kV double-circuit line, so servicing of the line will be efficient given its proximity to the existing circuit. B2M LP owns no station assets. Additionally, this type of asset is extremely reliable and has a very low probability of fault or other incident requiring corrective maintenance or repair expenditures.

**Table 1 - Summary of OM&A (\$ Millions)**

Description	Historical								Bridge		Test
	2015		2016		2017		2018		2019		2020
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Service Level Agreement Costs	0.9	0.7	0.8	0.8	0.8	1.0	2.0	1.1	0.8	0.7	0.7
Incremental Expenses	0.9	0.4	0.4	0.3	0.5	0.3	0.4	0.3	0.7	0.7	0.4
<b>Total OM&amp;A</b>	<b>1.8</b>	<b>1.1</b>	<b>1.2</b>	<b>1.1</b>	<b>1.2</b>	<b>1.3</b>	<b>2.4</b>	<b>1.4</b>	<b>1.5</b>	<b>1.3</b>	<b>1.2</b>

Witness: Jeffrey Smith

1 Over the 2015 to 2019 period, the OM&A spending has generally been on plan. The two  
2 exceptions would be:

3 (i) 2015, which saw spending below plan by about \$0.7 million, resulting from lower  
4 than anticipated Operating Services costs as discussed below and lower than  
5 anticipated Incremental expenses; and

6 (ii) 2018, which saw spending below plan by about \$1.0 million due mainly to  
7 variances in the Operating Services costs and the Transmission Rights-of-Way  
8 Maintenance as discussed below in Section 2.1.

9  
10 The proposed OM&A spending for the 2020 Test year is forecast to be \$1.2 million,  
11 consistent with the average annual spend over the historical years. The 2020 Test Year  
12 forecast represents a decrease of \$0.2 million over the 2019 Bridge year forecast. This  
13 decrease is related entirely to the forecast Regulatory expenses in 2019 in this  
14 Application. All other OM&A components are substantially unchanged in the Test Year,  
15 compared to the Bridge year. More details on the historical and future spending on each  
16 of these components are included below.

## 17 18 **2. KEY COMPONENTS OF THE OM&A EXPENDITURES**

### 19 20 **2.1 SERVICE LEVEL AGREEMENT COSTS**

21  
22 The bulk of the OM&A expenses required to satisfy the obligation and objectives of the  
23 company arise as the result of a Service Level Agreement between HONI and B2M LP.

24  
25 The costs for these services are estimated using the HONI fully-allocated costs incurred  
26 to perform the services outlined in the Service Level Agreement. Table 2 presents the  
27 required funding for these services in the 2020 Test Year, along with the actual and

Witness: Jeffrey Smith

1 planned spending levels for the bridge and historical years. Further details on these  
 2 services are provided in the following sections.

3  
 4 **Table 2 - Total Service Level Agreement Costs (\$ Millions)**

Description	Historical								Bridge	Test	
	2015		2016		2017		2018		2019	2020	
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Operations and Maintenance Expenses	0.7	0.4	0.5	0.5	0.5	0.8	1.8	0.9	0.6	0.4	0.5
Administrative and Corporate Expenses	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2
<b>Total Service Level Agreement Costs</b>	<b>0.9</b>	<b>0.7</b>	<b>0.8</b>	<b>0.8</b>	<b>0.8</b>	<b>1.0</b>	<b>2.0</b>	<b>1.1</b>	<b>0.8</b>	<b>0.7</b>	<b>0.7</b>

5  
 6 The actual to plan variances of the Service Level Agreement costs over the five-year  
 7 period (2015 to 2019) noted in Table 2 are mainly a result of the Operations and  
 8 Maintenance expenses due to:

- 9 (i) Lower than anticipated Operating Services costs. The actual Operating  
 10 Services costs were consistently below the original expectation by about \$0.2  
 11 million per year; and  
 12 (ii) Shifts in the timing of the execution of the Transmission Rights-of-Way  
 13 Maintenance work program. The timing of the execution of the forestry  
 14 services varied compared to plan but was substantially completed as expected  
 15 with actual costs within \$0.1 million of the original forecast over the five-year  
 16 period.

17  
 18 Looking forward, the proposed 2020 forecast for these services takes into consideration  
 19 the above trends by reducing the 2020 forecast for Operating Services expense by about  
 20 40% from previous period estimates to align with the actual level of expenditure over the  
 21 previous five years and by addressing the timing and expected expenditure of  
 22 Transmission Rights-of-Way Maintenance work program over the rate period.

Witness: Jeffrey Smith

1 **2.1.1 OPERATION AND MAINTENANCE EXPENSES**

2 The Operation and Maintenance expenses relate to the Operating Services and  
3 Maintenance Services performed by HONI, on behalf of B2M LP. Examples of the  
4 services received are listed below:

5  
6 **Operating Services:**

- 7 • Monitoring/Control of the transmission system, including alarm monitoring, asset  
8 monitoring, and minor control;
- 9 • Asset Operation within HONI-prescribed limits including application of HONI  
10 equipment directives and switching on HONI transmission system to regulate  
11 B2M LP 's transmission system;
- 12 • Emergency Response to transmission system events, including response to IESO-  
13 directed emergency actions, and implementation of load shedding;
- 14 • Outage Processing including scheduling, planning, and submitting to IESO;
- 15 • Crew Dispatching, including 24/7 assessment, contacting, and dispatching;
- 16 • Record Maintenance including retention of logged items, retention of SCADA  
17 information, and trip reports; and
- 18 • Power System IT Support of the power system applications used by operators.

19  
20 **Maintenance Services:**

- 21 • Overhead Transmission Lines maintenance including thermovision, helicopter  
22 and ground patrols; and
- 23 • Transmission Right-of-Way maintenance, including mandatory annual NERC  
24 vegetation patrols, line clearing, brush control, condition patrol and property  
25 owner notifications.

26  
27 Further details on the maintenance services are presented in B2M LP's Transmission  
28 System Plan in Attachment 1 to Exhibit B, Tab 3, Schedule 1.

Witness: Jeffrey Smith

**2.1.2 ADMINISTRATIVE AND CORPORATE EXPENSES**

The Administrative and Corporate Expenses include the costs arising from the support functions provided by HONI to B2M LP for administrative services and systems. The investment in those systems and the cost of their operation are incurred by HONI but are allocated to Hydro One Inc. and its affiliates through a cost allocation methodology.

This methodology lowers costs for all of the Hydro One Inc. subsidiaries by providing access to a sophisticated administration infrastructure at a lower cost than if each built its own unique and independent system. This sharing of the costs for a unified infrastructure benefits rate payers through lower rates and has been accepted by the Board in numerous previous proceedings, including B2M LP’s 2015 to 2019 Transmission Rates Application (EB-2015-0026). Further details on the common corporate costs and cost allocation methodology are provided in Exhibit F, Tab 4, Schedule 1.

**2.2 INCREMENTAL EXPENSES**

There are certain functions that must be executed by B2M LP to meet its obligations and objectives that are not supported by the Service Level Agreement with HONI. Table 3 presents the required funding in the 2020 Test Year, along with the actual and planned spending levels for the bridge and historical years. Further details on these functions are provided in the following sections.

**Table 3 - Total Incremental Expenses (\$ Millions)**

Description	Historical								Bridge		Test
	2015		2016		2017		2018		2019		2020
	Plan	Act	Plan	Act	Plan	Act	Plan	Act	Plan	Frcst	Frcst
Insurance	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Regulatory	0.3	-	-	-	-	-	-	-	0.3	0.3	-
Administrative	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Managing Director’s Office	0.4	0.3	0.2	0.2	0.2	0.1	0.2	0.1	0.2	0.2	0.2
<b>Total Incremental Expense</b>	<b>0.9</b>	<b>0.4</b>	<b>0.4</b>	<b>0.3</b>	<b>0.5</b>	<b>0.3</b>	<b>0.4</b>	<b>0.3</b>	<b>0.7</b>	<b>0.7</b>	<b>0.4</b>

Witness: Jeffrey Smith

1     **2.2.1   INSURANCE**

2     B2M is obligated, by agreement and by good utility practice, to maintain an appropriate  
3     level of insurance to protect its assets, its owners and its customers from catastrophic  
4     loss. B2M LP is fortunate to be able to leverage the existing Hydro One Inc. insurance  
5     policies, rather than procuring insurance protection unilaterally, resulting in cost savings  
6     for B2M LP. The annual premiums for this insurance are about \$0.1 million.

7  
8     **2.2.2   REGULATORY**

9     B2M LP incurs regulatory expenses related to its transmission rate application  
10    proceedings, which require rebasing on a five-year term based on the OEB Filing  
11    Requirements. The total amount anticipated in 2019 is \$0.3 million to cover costs for  
12    notice, studies, intervenors, OEB hearing charges and other items incurred directly by  
13    B2M LP. The 2020 Test Year does not include funding for this item. However, B2M LP  
14    does expect a similar level of regulatory expenses in the preparation of its next five-year  
15    transmission rate application and will need to manage this expense within the approved  
16    envelope.

17  
18    **2.2.3   ADMINISTRATIVE**

19    B2M LP incurs administrative expenses for other external fees and expenses not  
20    otherwise covered, such as auditor and professional fees, statutory remittances, and other  
21    items. The administrative expenses included in the 2020 Test Year are \$0.1 million, in  
22    line with the actual spend in the historical years.

23  
24    **2.2.4   MANAGING DIRECTOR'S OFFICE**

25    The partnership has one employee, the Managing Director, who is empowered to oversee  
26    and operate the partnership. The duties of this person include:

- 27       • Monitoring and ensuring that the terms and conditions of the partnership  
28       agreement are fulfilled;

Witness: Jeffrey Smith

- 1 • Working with employees from HONI and other entities to ensure that the  
2 Applicant and its assets are properly maintained and administered;
- 3 • Managing and Chairing Advisory Committee meetings with the partners on a  
4 regular basis, as spelled out in the partnership agreement;
- 5 • Ensuring that the partners are kept well informed and advised of the partnership's  
6 operations, and educated on what it means to be a transmission owner and  
7 operator in Ontario;
- 8 • Authorizing the disbursement of funds by the partnership to meets it obligations  
9 and expenses;
- 10 • Instituting communications with communities and the public at large, through  
11 meetings, websites and other media;
- 12 • Representing the partnership with various stakeholders at hearings, industry  
13 events and other situations; and
- 14 • Any and all other duties that may be required to represent the partnership and  
15 effectively support its operations.

16

17 To complete these tasks, the Managing Director's Office is provided an annual budget for  
18 things such as salary, office, communication, and other expenses that may be required.  
19 The total Managing Director's Office expense included in the 2020 Test year is \$0.2  
20 million in line with the average annual spend over the historical years.

Witness: Jeffrey Smith



1 B2M LP. This includes the provisions of operations and management services, fees and  
2 taxes, invoicing and payment, budgets, accounts and right to audit, liability and force  
3 majeure events, dispute resolution procedures, confidentiality and intellectual property,  
4 and term and termination of the agreement. More details on the key clauses are provided  
5 below.

6

7 **3.1 PROVISION OF OPERATIONS AND MANAGEMENT SERVICES**

8

9 The Agreement addresses the provision by HONI to B2M LP of operations, maintenance,  
10 and certain common administrative and corporate services. A description of the services  
11 contained in the Agreement is provided in Table 1.

12

13

**Table 1 - Service Level Agreement – 2020 to 2024**

<b>Services Provider</b>	<b>Services Recipient(s)</b>	<b>Description of Services</b>
Hydro One Networks Inc.	B2M LP	<i>a) Operations Services</i> – monitoring and control of the Transmission System, in accordance with the requirements of B2M LP’s Transmission Licence and all services required to fulfill all of B2M LP’s obligations under its Connection Agreement and the IESO-B2M LP operating requirements.
Hydro One Networks Inc.	B2M LP	<i>b) Maintenance Services</i> – all maintenance, repair and refurbishment services, in accordance with the requirements of B2M LP’s Transmission Licence and all services required to fulfill all of B2M LP’s obligations under its Connection Agreement and the IESO-B2M LP operating requirements.
Hydro One Networks Inc.	B2M LP	<i>c) Administrative and Corporate Services</i> – some corporate and administrative services provided by HONI, including finance and regulatory support, tax advice and returns preparation, treasury, communications and government relations, legal advice, real estate support, corporate security services, and First Nations support.

1 **3.2 FEES**

2  
3 Pursuant to the ARC, where a utility provides a service, resource product or use of an  
4 asset to an affiliate, the utility shall charge no less than the greater of (i) the market price  
5 of that service, product, resource or use of asset, and (ii) the utility's fully-allocated cost  
6 to provide that service, product, resource or use of asset. In purchasing a service,  
7 resource, product or use of an asset from an affiliate, a utility shall pay no more than the  
8 market price for that service, product, resource or use of asset. Where no market exists, a  
9 utility shall charge no less than its fully-allocated cost to provide the service, product,  
10 resource or use of asset, and shall pay no more than the affiliate's fully-allocated cost to  
11 provide the service, product, resource or use of asset. The level of costs for B2M LP's  
12 services was determined in accordance with the principles above.

13  
14 **3.3 BUDGETS, ACCOUNTS AND RIGHT TO AUDIT**

15  
16 HONI must provides HOIP with a proposed annual operating, maintenance and capital  
17 improvement Budget for the subsequent fiscal year at least 60 days prior to the  
18 commencement of the next fiscal year. Such annual Budget is accompanied by an annual  
19 operating plan prepared by HONI. HOIP notifies HONI, within 30 days after receipt of  
20 the Budget, of any issues with respect to such proposed Budget, and the two parties must  
21 cooperate with each other in developing a mutually acceptable Budget within the next 30  
22 days.

23  
24 HONI and HOIP agree that the Budget may be amended from time to time by mutual  
25 agreement to reflect revisions necessitated by unanticipated circumstances, including  
26 such as changes in applicable laws, additions or deletions to the scope of the services,  
27 emergencies and force majeure events.

Witness: Jeffrey Smith

1 If HONI becomes aware that the costs of services for the current fiscal year may exceed  
2 the Budget by 5% or more, HONI must promptly notify HOIP of such anticipated budget  
3 overrun and provide HOIP with a proposed amendment to the Budget.

4  
5 HOIP must notify HONI within 30 days after receipt of HONI's proposed Budget  
6 amendment of any issues, and the parties must cooperate with each other in developing a  
7 mutually acceptable amendment to the Budget. Except in the case of an emergency,  
8 HONI is not allowed to perform any services without the prior approval of HOIP, if such  
9 services would result in a cost overrun.

10  
11 In the event of an accident or emergency relating to the B2M LP assets, HONI may take  
12 action to address the situation without obtaining approval from HOIP. This may result in  
13 spending funds deemed by HONI to be reasonably necessary under the circumstances. As  
14 promptly and as reasonably practicable after HONI establishes control over such accident  
15 or emergency, HONI must furnish HOIP with a reasonably detailed written description of  
16 the accident or emergency and the manner in which such accident or emergency was  
17 handled by HONI. As well, B2M LP must pay HONI for these costs as incurred.

18  
19 Except in the case of an emergency, HONI must perform all services in accordance with  
20 the annual operating plan accompanying the Budget. HONI and HOIP agree to keep all  
21 necessary and proper accounts and records relating to services provided by HONI, and  
22 these accounts and records shall be open to audit and inspection for a period of six years.

### 23 24 **3.4 DISPUTE RESOLUTION PROCEDURE**

25  
26 If the parties have a dispute under the agreement that cannot be resolved by a conference  
27 of their respective senior officers, a written notice outlining the specifics of the dispute  
28 will be passed to the parties' respective Presidents. Five business days after receipt of

Witness: Jeffrey Smith

1 written notice, if the dispute remains unresolved, the matter is referred to arbitration for  
2 final resolution.

3  
4 **3.5 CONFIDENTIALITY AND INTELLECTUAL PROPERTY**

5  
6 Unless required by law, each party must maintain in strict confidence the Agreement and  
7 all information received from the other party. A party receiving confidential information  
8 shall not copy or disclose the information to any third party without the prior written  
9 consent of the disclosing party unless specifically stipulated in the Agreement.  
10 Confidential information remains the sole and exclusive property of the disclosing party.

11  
12 **3.6 TERM AND TERMINATION**

13  
14 The existing Agreement remains in force between B2M LP, HOIP and HONI until the  
15 Effective Date of the renewed Agreement. The renewed Agreement is for a term of five  
16 years commencing on the Effective Date, unless terminated early on at least twelve  
17 months' prior written notice from the terminating party.

18  
19 **4. COST-BASED PRICING**

20  
21 The fees payable to HONI are based on the proportion of a given service used by B2M  
22 LP. Where the fees payable for the services delivered are cost-based, such costs may be  
23 billed directly.

Witness: Jeffrey Smith

**THIS AGREEMENT FOR OPERATIONS SERVICES AND MANAGEMENT SERVICES** effective as of the 18<sup>th</sup> day of December, 2019.

**BETWEEN:**

**Hydro One Networks Inc.** ("Hydro One Networks")

-and-

**Hydro One Indigenous Partnerships GP Inc.** ("HOIP")

-and-

**B2M Limited Partnership** ("B2M LP") by its general partner,  
Hydro One Indigenous Partnerships GP Inc.

**WHEREAS:**

- 1) B2M LP is the transmitter licensed under the *Ontario Energy Board Act, 1998* to own and operate the second 500KV electric transmission tower line spanning approximately 180 kilometres from the Bruce Power Nuclear Generating Station in Kincardine, Ontario to Hydro One Networks' switchyard in Milton, Ontario (the "**BXM Line**"), which line went into commercial service in May 2012.
- 2) HOIP is an affiliate of Hydro One Networks within the meaning of the ARC.
- 3) B2M LP wishes to subcontract the operation of the BXM Line to Hydro One Networks as further set out herein.
- 4) B2M LP and Hydro One Networks are parties to an agreement for operations services and management services dated December 17, 2014 (the "2014 Services Agreement") and they have mutually agreed to terminate the 2014 Services Agreement.
- 5) HOIP wishes to obtain the assistance of Hydro One Networks, from time to time, via a new agreement in connection with certain management functions associated with the transmission business of B2M LP.
- 5) The parties are entering this Agreement to define their respective rights and obligations with respect to management and operation of the BXM Line.

**NOW THEREFORE** in consideration of the foregoing and the mutual covenants, agreements, terms and conditions contained herein, the parties intending to be legally bound hereby agree as follows:

## **ARTICLE I: DEFINITIONS**

### **1.1 Defined Terms**

Capitalized terms which are not otherwise defined herein shall have the meaning given to them in the ARC. In addition to terms defined elsewhere in this Agreement, unless there is something in the subject matter or context inconsistent therewith, the following capitalized terms, wherever used in this Agreement, shall have the following meanings:

"**Act**" means the *Ontario Energy Board Act, 1998*, as amended from time to time;

"**Agreement**" means this Agreement and all amendments made hereto by written Agreement between the parties in accordance with the terms of this Agreement;

"**ARC**" means the *Affiliate Relationships Code for Electricity Distributors and Transmitters* issued by the OEB in accordance with the Act, as amended from time to time;

"**B2M LP Transmission Licence**" means the licence or licences issued to B2M LP by the OEB pursuant to the Act and in effect from time to time;

"**Claims**" means all losses, costs, damages, expenses, injuries, liabilities, claims, demands and penalties, including reasonable legal fees, experts' fees and court costs, whether incurred through settlement or otherwise, and interest on each of these items, in each case whether arising prior to or after the termination of this Agreement.

"**Connection Facilities Agreement**" means the connection facilities agreement dated December 17, 2014 between B2M LP and Hydro One Networks governing the interconnection of the BXM Line with the transmission systems owned and operated by Hydro One Networks;

"**Effective Date**" shall be the date first written above.

"**Fees**" means collectively the Operations Fees and the Management Fees;

"**Force Majeure Event**" means, in relation to a Person, any event or circumstance, or combination of events or circumstances,

(i) that is beyond the reasonable control of the Person;

(ii) that adversely affects the performance by the Person of its obligations under this Agreement; and

(iii) the adverse effects of which could not have been reasonably foreseen or prevented, overcome, remedied or mitigated in whole or in part by the Person through the exercise of diligence and reasonable care and includes, but is not limited to, acts of war (whether declared or undeclared), invasion, armed conflict or act of foreign enemy, blockade, embargo, revolution, riot, insurrection, civil disobedience or disturbances, vandalism or acts of terrorism, strikes, lockouts, restrictive work practices or other labour disturbances, unlawful arrests or restraints by government or governmental, administrative or regulatory agencies or authorities unless the result of a violation by the Person of a permit, licence

or other authorization or of any applicable law, and acts of God including lightning, earthquake, fire, flood, landslide, unusually heavy or prolonged rain or accumulation of snow or ice or lack of water arising from weather or environmental problems; provided however, for greater certainty, that the lack, insufficiency or non-availability of funds shall not constitute a Force Majeure Event;

**"Good Utility Practice"** means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry in North America during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in North America;

**"IESO"** means the Independent Electricity System Operator established under the *Electricity Act, 1998*, or its successor;

**"IESO-B2M LP Operating Agreement"** means the operating agreement which B2M LP has or will enter with the IESO through which the IESO ensures that the BXM Line will be operated in a manner which does not compromise the operation or reliability of the IESO-controlled grid to which the BXM Line is connected;

**"OEB"** means the Ontario Energy Board established pursuant to the Act;

**"Operations Fees"** means the fees for the Operations Services, calculated and adjusted in accordance with this Agreement;

**"Operations Services"** means all services required in order to operate the BXM Line, including without limitation, all operating, maintenance, repair and refurbishment matters and including, without limiting the generality of the foregoing, all services in relation to the monitoring and control of the transmission of electricity across the BXM Line in accordance with the B2M LP Transmission Licence and all services required to fulfill all of B2M LP's obligations under the Connection Facilities Agreement and the IESO-B2M LP Operating Agreement;

**"Management Activities"** means the activities to be undertaken by HOIP in connection with the management of transmission business of the B2M LP which include:

- (i) obtaining (including preparation of applications therefor and submission thereof) licences, permits, approvals and rates required in connection with the BXM Line, the transmission of electricity thereby and the operation, maintenance, repair and replacement thereof;
- (ii) obtaining (including preparation of applications therefor and submission thereof) licences, permits, approvals and rates required in connection with the BXM Line and the transmission of electricity thereby;
- (iii) representation of B2M LP before the OEB;
- (iv) the making or filing of declarations, filings and registrations with, or notices to,

governmental authorities;

- (v) filing and managing warranty claims;
- (vi) procuring and maintaining the necessary inventory of replacement parts;
- (vii) maintaining records for B2M LP;
- (viii) defending any litigation commenced against B2M LP; and
- (ix) such other management activities associated with running the transmission business of B2M LP.

**"Management Fees"** means the fees for the Management Services, calculated and adjusted in accordance with this Agreement;

**"Management Services"** means services to be provided by Hydro One Networks to HOIP to assist HOIP with the performance of the Management Activities, which services will be requested in writing by HOIP from time to time;

**"Person"** means any natural person, sole proprietorship, partnership, corporation, trust, joint venture, governmental authority, incorporated or unincorporated entity, or incorporated or unincorporated association of any nature; and

**"Taxes"** means any and all applicable federal, state, provincial, or municipal taxes and duties including, but not limited to, sales, use, excise, value added, gross receipts, privilege or other non-recoverable taxes that are mandated or imposed on (i) Hydro One Networks by any jurisdiction or governmental entity in relation to the Operations Services and Management Services (other than taxes that are imposed upon the income, property, payroll or capital of Hydro One Networks), (ii) B2M LP (other than taxes that are imposed upon the income, property, payroll or capital of B2M LP or any of the partners of B2M LP), or HOIP (other than taxes that are imposed upon the income, property, payroll or capital of HOIP).

**"Term"** has the meaning ascribed to this term in Section 9.1 below.

## **ARTICLE II: PROVISION OF OPERATIONS AND MANAGEMENT SERVICES**

2.1 B2M LP may perform any Operations Services or engage another supplier to perform such services if Hydro One Networks is in default in performing its material obligations hereunder or is unable to perform its material obligations hereunder by reason of a Force Majeure Event, to the extent such services are required to ensure the continued operation of the BXM Line.

2.2 HOIP shall be responsible for all Management Activities related to the transmission business of B2M LP. HOIP may make a request in writing, from time to time, to Hydro One Networks, for Management Services to assist HOIP in connection with the Management Activities. Hydro One Networks agrees to provide to HOIP those Management Services requested in writing by HOIP.

2.3 Hydro One Networks shall at all times provide Operations Services and Management Services in accordance with Good Utility Practice, the B2M LP Transmission Licence, the ARC, all other applicable codes, rules, orders and decisions of the OEB, which are binding upon the BXM Line, all applicable law, and provided they are not inconsistent with any of the foregoing, Hydro One Networks' own policies and procedures (which may include government directives), and shall do so in the same manner and to the same extent as it provides similar services in connection with its wholly-owned regulated transmission business. Hydro One Networks shall comply with all applicable laws in providing the Operations Services and Management Services.

2.4 To the extent that Hydro One Networks also provides services similar to the Operations Services or Management Services in respect of its own assets or business, Hydro One Networks will provide such Operations Services and Management Services in a non-discriminatory manner as if it were providing such services to itself or receiving a similar service in relation to its own transmission assets or business. The Fees for such Operations Services and Management Services shall be consistent with the costs incurred by Hydro One Networks for such similar services in relation to Hydro One Networks' transmission assets or business activities which are substantially similar to the BXM Line and business activities of B2M LP.

2.5 Upon expiration or termination of this Agreement, and provided that B2M LP is not in default of paying the Fees owing hereunder, Hydro One Networks shall provide, at the request of B2M LP, reasonable transition support services to facilitate transition to another operating and management services entity, reimbursable on the basis of the "fully allocated cost" (as defined in the ARC), and otherwise on the terms hereof, for a period of six months following the expiration or effective date of termination of this Agreement, or such shorter period as B2M LP may request. The provisions of this Section 2.5 shall forever survive the termination or expiration of this Agreement.

2.8 Hydro One Networks shall obtain and maintain in force throughout the Term of this Agreement, insurance coverage that a reasonable and prudent Person operating a transmission business of a comparable size and scale of Hydro One Networks would carry as part of its business. Hydro One Networks shall add B2M LP as an additional named insured under Hydro One Networks' insurance program and allocate to B2M LP, as Fees, a portion of the premium therefor and any incremental costs borne by Hydro One Networks in accommodating the unique circumstances of B2M LP (e.g. reducing deductibles to such reasonable levels requested by B2M LP).

### **ARTICLE III: FEES**

3.1 B2M LP shall pay, without duplication, the Operations Fees and all applicable Taxes to Hydro One Networks for the performance of the Operations Services.

3.2 HOIP shall pay, without duplication, the Management Fees and all applicable Taxes to Hydro One Networks for the performance of the Management Services.

3.3 The Fees for Operations Services and Management Services shall be Hydro One Networks' fully allocated costs of providing the Operations Services and Management Services (excluding Hydro One Networks' return on investment on capital), as applicable and in a manner consistent with the ARC. Hydro One Networks shall, from time to time as required to keep the information current, and in any event, no less frequently than annually, provide B2M LP with a breakdown of Hydro One Network's fully allocated costs of providing the Operations Services and the Management

Services.

3.4 **Intentionally deleted.**

3.5 HOIP shall use commercially reasonable efforts to recover the Fees payable hereunder by B2M LP and HOIP in the B2M LP transmission rate revenue requirement submissions to the OEB and representations to be made to the OEB in connection therewith.

**ARTICLE IV: INVOICING AND PAYMENT**

4.1 All amounts payable by B2M LP and HOIP to Hydro One Networks under this Agreement shall be paid in accordance with the invoices rendered by Hydro One Networks to be issued on a periodic basis matching the time period for which B2M LP receives payments for the transmission of electricity. B2M LP and HOIP shall pay Hydro One Networks' invoices within 30 days of receipt thereof.

**ARTICLE V: BUDGETS, ACCOUNTS AND RIGHT TO AUDIT**

5.1 Hydro One Networks shall, for each fiscal year of the Term hereof, provide HOIP with a proposed annual operating, maintenance and capital improvement budget for the subsequent fiscal year of B2M LP (the "**Budget**") at least sixty (60) days prior to the commencement of the next fiscal year. Such annual Budget shall be accompanied by an annual operating plan prepared by Hydro One Networks setting forth the underlying assumptions and plans in connection with the Budget, and setting forth a brief description of any major system repairs anticipated to be required in such fiscal year. HOIP shall notify Hydro One Networks as soon as reasonably practicable, but no later than thirty (30) days after receipt of the Budget, of any questions, comments, objections or suggested modifications which it may have with respect to such proposed Budget, and the parties shall cooperate with each other in developing a mutually acceptable Budget within thirty (30) days thereof. If HOIP fails to raise any questions, comments, objections or suggested modifications to the proposed Budget within thirty (30) days after receipt of the proposed Budget, the proposed Budget shall be deemed to have been approved.

5.2 Each Budget will represent Hydro One Networks' estimate of all fully allocated costs for providing the Operations Services under this Agreement during the period to which the Budget relates, and its estimate of all capital improvements required for providing the Operations Services, during the period to which the Budget relates.

5.3 The parties agree that the Budget may be amended from time to time by mutual agreement to reflect revisions necessitated by unanticipated circumstances including, but not limited to, changes in applicable law, additions or deletions to the scope of the Operations Services hereunder, emergencies and Force Majeure events, provided that Hydro One Networks shall not be required to amend the Budget more frequently than would be required under its normal business and operations practices.

5.4 The Budget shall reflect anticipated costs of Operations Services by Hydro One Networks on a monthly or quarterly basis and shall be organized by categories mutually agreed upon by the

parties. If Hydro One Networks becomes aware that the costs of Operations Services for the current fiscal year may exceed the Budget by 5% or more of the total amount of the Budget, Hydro One Networks shall promptly notify HOIP of such anticipated budget overrun and provide HOIP a proposed amendment to the Budget. HOIP shall notify Hydro One Networks as soon as reasonably practicable, but no later than thirty (30) days after receipt of Hydro One Networks' proposed Budget amendment of any questions, comments, objections or suggested modifications thereto and the parties shall cooperate with each other in developing a mutually acceptable amendment to the Budget. If HOIP fails to raise any questions, comments, objections or suggested modifications to the proposed Budget amendment within the specified period, Hydro One Networks' proposed amendment shall be deemed to have been approved. Hydro One Networks shall not, without the written approval of HOIP amending the Budget or otherwise authorizing such expenditure, perform any further services or incur any further costs that would result in or increase such Budget overrun, except in the case of an emergency as provided in Section 5.7.

5.5 If by the start of any fiscal year the parties are unable to reach agreement concerning the Budget for such year, then, until such time as agreement is reached, the Budget for such year shall be based on the corresponding portions of the Budget for the preceding fiscal year, adjusted as follows: (i) with respect to items of expense that do not involve capital additions or improvements, to reflect the net change, if any, between the most recently published Ontario Consumer Price Index, published by Statistics Canada, not seasonally adjusted and the corresponding index in effect twelve months prior, and (ii) with respect to items of expense involving capital additions or improvements, to reflect the net change, if any, between the most recently published Producer Price Index for Capital Equipment, not seasonally adjusted, and the corresponding index in effect twelve months prior.

5.6 In the event that Hydro One Networks determines that a capital improvement, addition, alteration, repair or replacement not included in the Budget that has an impact of more than 5% of the total amount of the Budget should be made to the BXM Line in order to operate the BXM Line safely or comply with any laws, regulations or orders of any governmental authority, including laws, regulations or orders relating to environmental compliance or employee safety, Hydro One Networks shall provide HOIP with a written notice describing the nature of and reason for the improvement, addition, alteration, repair or replacement. Hydro One Networks shall not make any such improvement, addition, alteration, repair or replacement without HOIP's prior consent, which consent shall not be unreasonably withheld or delayed. In the event that HOIP refuses to approve of any such Hydro One Networks recommended improvement, addition, alteration, repair or replacement, Hydro One Networks shall have the option to terminate this Agreement in accordance with Section 9.3

5.7 In the event of an accident or emergency relating to the BXM Line, Hydro One Networks may, without obtaining any approvals of HOIP which might otherwise be required hereunder, take any action, including, but not limited to, committing or expending funds, deemed by Hydro One Networks to be reasonably necessary under the circumstances. As promptly as reasonably practicable after Hydro One Networks establishes control over such accident or emergency, Hydro One Networks shall furnish to HOIP a reasonably detailed written description of the accident or emergency and the manner in which such accident or emergency was handled by Hydro One Networks. Hydro One Networks shall be entitled to compensation for costs incurred pursuant to this Section 5.7 in addition to all other compensation provided for under this Agreement.

5.8 Except as provided by Section 5.7 in the case of an emergency, Hydro One Networks shall perform all services hereunder in accordance with the annual operating plan accompanying the Budget.

5.9 The parties hereby agree to keep all necessary and proper accounts and records relating to the subject matter hereof. Such accounts and records, including invoices, receipts, time cards and vouchers shall at all reasonable times be open to audit, inspection and copying by each party to this Agreement. Accounts and records shall be preserved and kept available for audit for a period of six years.

## **ARTICLE VI: LIMITATION OF LIABILITY AND FORCE MAJEURE EVENTS**

6.1 Other than for sums payable under this Agreement, Hydro One Networks shall only be liable to B2M LP and HOIP and B2M LP and HOIP shall only be liable to Hydro One Networks for any damages that arise directly out of its gross negligence or willful misconduct in meeting its respective obligations under this Agreement. Notwithstanding the generality of the foregoing, neither party shall be liable to the other party under any circumstances whatsoever for any loss of profits or revenues, business interruption losses, loss of contract or loss of goodwill, or for any indirect, consequential or incidental damages, including but not limited to punitive or exemplary damages, whether any of the said liability, loss or damages arise in statute, contract, tort or otherwise.

6.2 In any event, except with respect to gross negligence or willful misconduct, the total liability of Hydro One Networks to B2M LP and HOIP and the total liability of B2M LP and HOIP to Hydro One Networks in connection with this Agreement whether it arises by statute, contract, tort or otherwise, will not exceed the value of the total amounts payable by B2M LP and HOIP to Hydro One Networks for the Operations Services and Management Services in the year that such liability is incurred.

6.3 No party shall be liable to the other for any loss, damage or delay, or inability to perform any obligation under this Agreement in whole or in part due to a Force Majeure Event.

6.4 B2M LP will indemnify and save harmless Hydro One Networks providing Operations Services from and against any and all Claims that Hydro One Networks may suffer, sustain or incur in connection with the provision of the Operations Services except to the extent caused or arising from the gross negligence or wilful misconduct of Hydro One Networks.

6.5 If a Force Majeure Event prevents a party from performing any of its obligations under this Agreement, such party shall (1) expeditiously, and without delay, notify the other party of the Force Majeure Event and its good faith assessment of the effect that the Force Majeure Event will have on its ability to perform any of its obligations, which notice shall be confirmed in writing as soon as reasonably practicable if such immediate notice is not in writing; (2) not be entitled to suspend performance of any of its obligations under the Agreement to any greater extent or for any longer duration than is caused by the Force Majeure Event; (3) use commercially reasonable efforts to mitigate the effects of such Force Majeure Event and to resume full performance of its obligations hereunder; (4) keep the other party informed of such efforts on a continuing basis; and (5) provide written notice to the other party of the resumption of the performance of any

obligations affected by the Force Majeure Event.

6.6 Notwithstanding any of the foregoing, settlement of any strike, lockout, or labour dispute constituting a Force Majeure Event shall be within the sole discretion of the party to the Agreement involved in such strike, lockout, or labour dispute and the requirement that a party must use commercially reasonable efforts to mitigate the effects of a Force Majeure Event and resume full performance hereunder shall not apply to strikes, lockouts, or labour disputes.

6.7 The provisions of this Article VI shall forever survive the termination or expiration of this Agreement.

## **ARTICLE VII: DISPUTE RESOLUTION PROCEDURES**

7.1 Any controversy, dispute, difference, question or claim (collectively "Dispute"), arising between the parties in connection with the interpretation, performance, construction or implementation of this Agreement that cannot be resolved by a conference of senior officers of Hydro One Networks and HOIP shall be settled in accordance with this section. The aggrieved party shall send the other party written notice identifying the Dispute, the amount involved, if any, and the remedy sought. The Presidents from each party shall confer in an effort to resolve the Dispute. If the Presidents are unable to resolve the Dispute within 5 business days after receipt of the written notice of the Dispute, then a party may refer the Dispute to adjudication in court or, if all parties agree, to arbitration before a single arbitrator. Insofar as they do not conflict with this Section 7.1, the Rules for Procedure for Commercial Arbitration of the Arbitration and Mediation Institute of Canada Inc./International Chamber of Commerce Rules of Arbitration in effect at the date of commencement of any arbitration held under this Agreement will apply to the arbitration. A party hereto may enter any judgment upon any award rendered by the arbitrator in any court having jurisdiction. The arbitration will be conducted in English under the *Arbitration Act, 1991* (Ontario) and will take place at such time and place as the arbitrator may fix. Notwithstanding the foregoing, if the subject matter of any Dispute is also the subject matter of a Dispute under Section 13 of the Limited Partnership Agreement governing the B2M LP, the resolution of the Dispute under the Section 13 of the Limited Partnership Agreement governing B2M LP shall govern and be applicable to the resolution of the Dispute under this Agreement and such matter shall not be subject to further arbitration or adjudication under this Agreement.

## **ARTICLE VIII: CONFIDENTIALITY AND INTELLECTUAL PROPERTY**

8.1 Each party (the "**Receiving Party**") shall maintain in strict confidence this Agreement and the existence and contents thereof and all confidential or proprietary information of the other party, (the "**Disclosing Party**") or any of the Disclosing Party's directors, officers, employees, consultants, agents or legal, financial or professional advisors (the "**Disclosing Party Representatives**") (collectively the "**Confidential Information**"). Except as permitted herein, the Receiving Party shall not publish, reproduce, or disclose, either directly or indirectly, the said Confidential Information to any third party and shall not use the said Confidential Information for any purpose other than for purposes of this Agreement without the prior written consent of the Disclosing Party. The Receiving Party may disclose the Confidential Information only to its partners, shareholder, directors, officers, employees, consultants, agents, professional advisors or lenders (the "**Receiving Party Representatives**") having a need to know same and who have undertaken a like obligation to maintain its confidentiality. For greater certainty, Confidential Information includes any and all personal information (as that term is defined in the *Personal Information Protection and Electronic*

*Documents Act* (Canada), as they may be amended) and any and all information regarding a consumer, retailer, wholesale buyer, wholesale supplier, or a generator, provided by the Disclosing Party to the Receiving Party for purposes of this Agreement.

8.2 The Receiving Party undertakes to protect and safeguard all Confidential Information in its possession or under its control and received by the Disclosing Party, in the manner described in Schedule "A" attached hereto. The Disclosing Party may, on reasonable notice, and during regular business hours, audit the information management practices of the Receiving Party to confirm compliance with the terms and conditions of this Article VIII and all applicable statutes, regulations, by-laws, standards and codes, as amended.

8.3 The Receiving Party undertakes to notify the Disclosing Party immediately upon discovery of any unauthorized use and/or disclosure of any of the Disclosing Party's Confidential Information, to co-operate with the Disclosing Party to help regain possession of such Confidential Information, and to prevent its further unauthorized use and/or disclosure.

8.4 The forgoing obligations with respect to confidentiality, use, reproduction, dissemination, publication and non-disclosure herein shall not apply to any information that:

- (i) is previously known to or lawfully in the possession of the Receiving Party;
- (ii) is independently known to or discovered by the Receiving Party, without any reference to the information or material;
- (iii) is obtained by the Receiving Party from an arm's length third party having a bona fide right to disclose same and who was not otherwise under an obligation of confidence or fiduciary duty to the Disclosing Party or the Disclosing Party Representatives;
- (iv) is or becomes public knowledge through no fault or omission of, or breach of this Agreement by, the Receiving Party or the Receiving Party Representatives; or
- (v) is required to be disclosed pursuant to a final judicial or governmental order or other legal process, including, without limitation, an order of or legal process involving a regulatory authority such as the Ontario Energy Board.

8.5 The parties acknowledge and agree that the Confidential Information (other than Confidential Information contained in this Agreement which shall be jointly owned by the parties) shall remain the sole and exclusive property of the Disclosing Party that has disclosed the Confidential Information, and the Disclosing Party shall retain all right, title and interest in and to the Confidential Information it has disclosed to the Receiving Party.

8.6 The Receiving Party agrees that it shall keep a record of written Confidential Information furnished to it by the Disclosing Party in a location separate from those locations where the Receiving Party has stored information in respect of other third parties for which it performs work and it shall advise the Disclosing Party of such location.

8.7 All Confidential Information furnished by the Disclosing Party (other than this Agreement), including that portion of the Confidential Information which is contained in analyses, compilations, studies or other documents prepared by the Receiving Party or by the Receiving Party Representatives, is the Disclosing Party's property and will be returned immediately to the Disclosing Party upon its request except that any information, plans, layouts, specifications, descriptions or other information necessary to the continued operation and maintenance of the BXM Line and its parts and components, or to the replacement of any such parts or components, need not be returned and

may be used or applied in the continued operation and maintenance of the BXM Line.

8.8 The obligations in this Article VIII shall forever survive the termination or expiration of this Agreement.

## **ARTICLE IX: TERM AND TERMINATION**

9.1 Except as otherwise specified herein and subject to early termination rights in Sections 5.6, and 9.3, this Agreement shall continue in full force and effect for a term of five years commencing on the Effective Date (the “**Term**”).

9.2 Except for those provisions in the 2014 Services Agreement which survive termination thereof as specified therein, the 2014 Services Agreement is terminated as of the Effective Date.

9.3 Hydro One Networks may terminate this Agreement on 60 days’ prior written notice in the event that B2M LP refuses to approve a capital improvement, addition, alteration, repair or replacement recommended by Hydro One Networks in accordance with Section 5.6.

9.4 In the event of termination or expiration of this Agreement: (i) Hydro One Networks shall deliver to HOIP all books, records and accounts which it has developed and maintained relating solely to the BXM Line or its operations or the business of B2M LP and return all property owned by B2M LP, and (ii) the parties shall take all steps as may be reasonably required to complete any final accounting between them or to provide for the completion of matters contemplated hereunder.

## **ARTICLE X: GENERAL**

10.1 This Agreement shall be governed by and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

10.2 The rights and obligations of the parties under this Agreement shall at all times be subject to all applicable laws, regulations, orders and directives of any authority of competent jurisdiction, including the OEB, and shall be deemed to be amended to the extent required to comply with same.

10.3 This Agreement constitutes the entire Agreement between the parties with respect to the Operations Services and Management Services and supersedes all prior oral or written representations and Agreements concerning the subject matter of this Agreement.

10.4 This Agreement shall extend to, be binding upon and enure to the benefit of the permitted assigns and the respective successors of B2M LP, HOIP and Hydro One Networks.

10.5 Neither this Agreement nor any provision hereof is intended to confer upon any Person other than the parties hereto any rights or remedies hereunder.

10.6 If any party determines that in its reasonable discretion that any further instruments or other actions seem necessary or desirable to carry out the terms of this Agreement, the other parties shall execute and deliver all such instruments and do all such actions as such parties agree in their reasonable discretion as necessary or desirable to carry out the terms of this Agreement.

10.7 No delay or failure in exercising any right under this Agreement or any partial or single exercise of any right, will constitute a waiver of that right or any other rights under this Agreement. No consent to a breach of any express or implied term set out in this Agreement constitutes consent to any subsequent breach.

10.8 If any term, covenant or condition of this Agreement or the application or effect of any such term, covenant or condition is held to be invalid as to any Person, entity or circumstance or is determined to be not in the public interest by any court or government agency of competent jurisdiction, then such term, covenant or condition shall remain in effect to the maximum extent permitted by law and, all other terms, covenants and conditions of this Agreement and their application shall not be affected, but shall remain in full force and effect and the parties shall be relieved of their respective obligations under this Agreement only to the extent necessary to comply with the court or government agency holding.

10.9 This Agreement does not and shall not be construed to create or establish a partnership, agency, joint venture, lease, licence or any other relationship between the parties hereto, nor constitute either party as an agent of the other. Neither party hereto shall hold itself out to others by act or omission, contrary to the terms of this Agreement.

10.10 This Agreement and the rights and obligations hereunder may not be assigned in whole or in part by Hydro One Networks except with the prior written consent of B2M LP, in its sole discretion. This Agreement and the rights and obligations hereunder may not be assigned in whole or in part by B2M LP other than (i) to the transferee of the BXM Line approved by the OEB, or (ii) with the prior written consent of Hydro One Networks, in its sole discretion.

10.11 This Agreement and any amendment, supplement, restatement or termination of this Agreement in whole or in part may be signed and delivered in any number of counterparts, each of which when signed and delivered is an original, but all of which taken together constitute one and the same instrument. This Agreement and any amendment, supplement, restatement or termination of this Agreement in whole or in part may be delivered by means of facsimile or via e-mail in portable document format (PDF).

**IN WITNESS WHEREOF**, the parties hereto have caused this Agreement to be executed by the signatures of their representatives duly authorized in that behalf.

**HYDRO ONE NETWORKS INC.**

---

Name:  
Title:  
I have the authority to bind the  
corporation.

**B2M LIMITED PARTNERSHIP, by its  
general partner, HYDRO ONE  
INDIGENOUS PARTNERSHIPS GP INC.**

---

Name:  
Title:  
I have the authority to bind the  
corporation.

**HYDRO ONE INDIGENOUS  
PARTNERSHIPS GP INC.**

---

Name:  
Title:  
I have the authority to bind the  
corporation.

## Schedule "A"

### Receiving Party Security Safeguards Regarding Confidential Information Received from the Disclosing Party

*The Receiving Party shall protect the Confidential Information by security safeguards appropriate to the sensitivity of the information.*

- 1) The Receiving Party shall protect the Confidential Information against such risks as loss or theft, unauthorized access, disclosure, copying, use, modification or destruction, through appropriate security measures, regardless of the format in which it is held.
- 2) All of the Receiving Party's Representatives with access to the Confidential Information shall be contractually required to respect the confidentiality of that information.
- 3) The Receiving Party acknowledges and agrees that the nature of the safeguards will vary depending on the sensitivity, amount, distribution and format of the information, and the method of storage. The Receiving Party shall ensure that more sensitive information will be safeguarded by a higher level of protection.
- 4) The Receiving Party shall ensure that methods of protection will include:
  - (a) physical measures, for example, locked filing cabinets and restricted access to offices;
  - (b) organizational measures, for example, controlling entry to data centers and limiting access to information on a "need-to-know" basis;
  - (c) technological measures, for example, the use of passwords and encryption;  
and
  - (d) investigative measures, in cases where the Receiving Party has reasonable grounds to believe that the Confidential Information is being inappropriately collected, used or disclosed by anyone whom in law the Receiving Party is responsible.

1                   **COMMON CORPORATE COSTS, COST ALLOCATION**  
2   **METHODOLOGY**

3  
4       Allocation of Common Corporate Costs to HONI's Distribution and Transmission  
5       businesses, to other Hydro One affiliates, and to B2M LP is based on an established cost  
6       allocation approach supported by cost causality principles.

7  
8       The Common Corporate Costs OM&A programs include the support of Corporate  
9       Common Functions and Services ("CCF&S"), Asset Management, Information  
10      Technology, and Operating Programs.

11  
12      Specifically related to B2M, the allocated CCF&S costs are for services provided by  
13      Finance, Taxation, Planning, Security Operations, Real Estate Services, Indigenous  
14      Relations, Regulatory Affairs and General Counsel.

15  
16      Since 2004, in connection with each major cost of service application, Hydro One has  
17      commissioned a study by Black and Veatch to recommend a best practice methodology  
18      to allocate common corporate costs among the business entities using the common  
19      services. The adopted methodology represents the industry's best practices, identifying  
20      appropriate cost drivers to reflect cost causality and benefits received. In this  
21      Application, B2M LP has included the same corporate cost allocation highlighted by  
22      Black and Veatch in HONI's Transmission Rate Application (EB-2019-0082) in Exhibit  
23      F, Tab 2, Schedule 6, Attachment 1.

24  
25      The allocation of Common Corporate Costs to B2M LP for the test years (2020 to 2024)  
26      is forecast to be \$0.2 million annually. This is consistent with actual costs for the period  
27      2015 to 2019, which were \$0.2 million annually and consistent with the OEB approved  
28      levels for that period.

Witness: Joel Jodoin



1 **2. DEPRECIATION EXPENSE**

2  
3 B2M LP relied upon HONI's new depreciation study for transmission assets completed in  
4 2017, which used the Foster methodology to determine the depreciation rates proposed to  
5 be used in the calculation of depreciation expenses for 2020. Detailed depreciation  
6 schedules are filed at Exhibit F, Tab 5, Schedule 1, Attachment 2. The depreciation  
7 expenses for 2015 to 2020 are summarized in Table 1.

8  
9 **Table 1 - B2M LP Depreciation Expense (\$ Million)**

Description	Historical				Bridge	Test
	2015	2016	2017	2018	2019	2020
Depreciation On Fixed Assets	7.2	7.2	7.2	7.2	7.2	7.0
Less Capitalized Depreciation	-	-	-	-	-	-
Asset Removal Costs	-	-	-	-	-	-
Losses/(Gains) On Asset Disposition	-	-	-	-	-	-
<b>Total</b>	<b>7.2</b>	<b>7.2</b>	<b>7.2</b>	<b>7.2</b>	<b>7.2</b>	<b>7.0</b>

# 2017 Depreciation Rate Review



— *Transmission Operations*

# CONTENTS

<b>EXECUTIVE SUMMARY</b>	<b>SECTION I</b>
INTRODUCTION .....	1
PLANT ACCOUNT STRUCTURE .....	1
CURRENT DEPRECIATION RATES .....	2
2017 DEPRECIATION RATE REVIEW .....	3
SCOPE OF REVIEW .....	3
DEPRECIATION SYSTEM .....	3
RECOMMENDED DEPRECIATION RATES .....	4
<b>STUDY PROCEDURE</b>	<b>SECTION II</b>
INTRODUCTION .....	6
SCOPE .....	6
DATA COLLECTION .....	6
LIFE ANALYSIS AND ESTIMATION .....	7
CLASS/CATEGORY SERVICE LIVES .....	10
USOA SERVICE LIVES .....	11
DEPRECIATION RESERVE ANALYSIS .....	11
DEVELOPMENT OF ACCRUAL RATES .....	12
<b>STATEMENTS</b>	<b>SECTION III</b>
INTRODUCTION .....	15
STATEMENT A – REMAINING–LIFE ACCRUAL RATES .....	16
STATEMENT B – REMAINING–LIFE ACCRUALS .....	17
STATEMENT C – DEPRECIATION RESERVE SUMMARY .....	18
STATEMENT D – CURRENT AND PROPOSED PARAMETERS .....	19
STATEMENT E – ASSET CATEGORY SUMMARY (BU 210) .....	20
<b>ANALYSIS</b>	<b>SECTION IV</b>
INTRODUCTION .....	28
SCHEDULE A – GENERATION ARRANGEMENT .....	28
SCHEDULE B – AGE DISTRIBUTION .....	29
SCHEDULE C – PLANT HISTORY .....	29
SCHEDULE D – ACTUARIAL LIFE ANALYSIS .....	30
SCHEDULE E – GRAPHICS ANALYSIS .....	30

**TRANSMISSION**

1715 – STATION EQUIPMENT

SCHEDULE A – GENERATION ARRANGEMENT ..... 24  
SCHEDULE B – AGE DISTRIBUTION ..... 26  
SCHEDULE C – PLANT HISTORY ..... 28  
SCHEDULE D – ACTUARIAL LIFE ANALYSIS ..... 30  
SCHEDULE E – GRAPHICS ANALYSIS ..... 33

**EXPERT RULE 13A**

**SECTION V**

CONFIRMATION ..... 36  
FORM A ..... 37  
PROFESSIONAL QUALIFICATIONS ..... 38

*Executive Summary*

# EXECUTIVE SUMMARY

## INTRODUCTION

This report presents a review and update of depreciation rates and parameters for Transmission plant owned and operated by Hydro One Networks Inc. (Company or Hydro One Networks). Work on this review, conducted by Foster Associates Consultants, LLC (Foster Associates), commenced in March 2017 and progressed through mid-August, at which time the project was completed.

Foster Associates is a public utility economic consulting firm headquartered in Fort Myers, Florida offering economic research and consulting services on issues and problems arising from governmental regulation of business. Areas of specialization supported by our Fort Myers office include service life and technological forecasting, depreciation estimation, and valuation of industrial property.

Foster Associates has undertaken numerous depreciation engagements for both public and privately owned business entities, including detailed statistical life studies, analyses of required net salvage rates, and the selection of depreciation systems that will most nearly achieve the goals of depreciation accounting under the constraints of either government regulation or competitive market pricing. Foster Associates is widely recognized for industry leadership in the development of depreciation systems, life analysis techniques and computer applications for conducting depreciation and valuation studies.

## PLANT ACCOUNT STRUCTURE

The hierarchical structure of plant accounting records maintained by Hydro One Networks for major asset categories provides: a) Uniform System of Account (USoA) categories; b) cost of asset components (Category ID); and c) vintage identification (Asset ID).

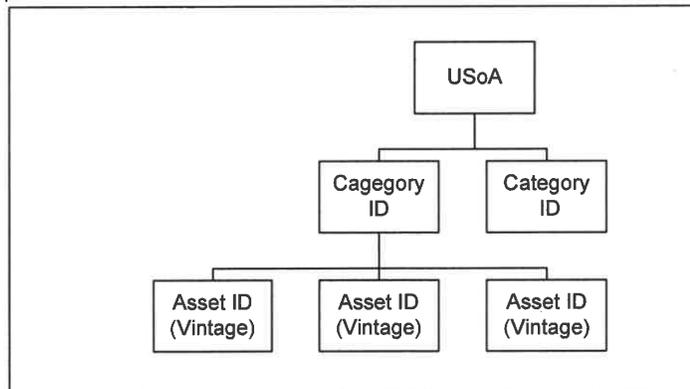


Fig. 1 Account Structure

The lowest level at which the installed cost of a property unit (*e.g.*, a single pole or transformer) can be estimated is by vintage year of placement within a Category ID. (The cost of a property unit within a vintage can be estimated by dividing the vintage cost by the recorded number of installed property units). A Category ID is

an aggregation of vintage costs sharing common physical or functional attributes. All vintages of power transformers larger than 230 kV, for example, or all vintages of underground cable are classified in unique Category IDs. It is neither practical nor feasible, however, to estimate service lives and maintain accumulated depreciation reserves for each property unit.

### **CURRENT DEPRECIATION RATES**

Depreciation rates currently used by Hydro One Networks for Transmission and Common operations were developed in a 2013 depreciation review conducted by Foster Associates. The Ontario Energy Board (OEB) approved depreciation expense derived from the depreciation review pursuant to a Settlement Agreement in EB-2014-0140 (Rate Order dated January 8, 2015).<sup>1</sup>

Life tables were constructed in the 2015 review for each USoA plant account for which retirements were recorded over the period 2000-2014. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate measurements of service life. These results were directly attributable to insufficient retirement experience over the available band of activity years.

Absent the availability of sufficient retirement activity to conduct statistical service life studies, depreciation rates developed in the 2015 review were derived from a composite of category lives for class categories established by Hydro One Networks in 2008 in preparation for implementation of International Financial Reporting Standards (IFRS) and reviewed in 2013. While Hydro One Networks has received an exemption from an otherwise mandatory adoption of IFRS for rate regulated entities, the Company intends to continue maintaining category classifications for engineering operations and business planning purposes.

The review of category lives undertaken in 2013 included onsite meetings with Company engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates. Discussions were held with representatives from planning, operations, maintenance, information technology and facilities to assess the reasonableness of recommended category lives within their respective areas of expertise. Consideration was also given to the range of service lives recommended in the Asset Amortization Study prepared for the Ontario Energy Board by Kinectrics Inc.

---

<sup>1</sup> Depreciation rates were subsequently developed in a 2015 depreciation review in EB-2016-0160 for 2017 and 2018 rate setting purposes. Rates developed in the 2015 review have been retained pending a decision in EB-2016-0160.

Projection lives for USoA categories were derived from harmonic weighting of the constituent category lives recommended by the project team. Iowa survivor curves considered descriptive of the forces of retirement acting upon each USoA category were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions.

## **2017 DEPRECIATION RATE REVIEW**

The principal findings and recommendations of the Hydro One Networks 2017 Depreciation Rate Review are summarized in the Statements section of this report. Statement A provides a comparative summary of current and recommended annual depreciation rates for each USoA rate category. Statement B provides a comparison of current and recommended annual depreciation accruals. Statement C provides a comparison of recorded, computed and redistributed depreciation reserves for each rate category. Statement D provides a comparative summary of current and recommended parameters including projection life, projection curve, average service life, and average remaining life. Statement E provides the computation of recommended USoA projection lives derived from an analysis of component category lives.

### **Scope of Review**

Principal activities undertaken in the 2017 review included:

- Collection of plant and reserve data;
- Reconciliation of assembled database to Company records;
- Discussions with Hydro One Networks plant accounting personnel;
- Estimation of projection lives and retirement dispersion patterns;
- Analysis and redistribution of recorded depreciation reserves; and
- Development of recommended accrual rates for each rate category.

### **Depreciation System**

A depreciation rate is formed by combining the elements of a depreciation system composed of a method, a procedure and a technique. A depreciation method (*e.g.*, straight-line) describes the system component that produces acceleration or deceleration of depreciation accruals in relation to either time or use. A depreciation procedure (*e.g.*, vintage group) identifies the level of grouping or sub-grouping of assets within a plant category. The level of grouping specifies the weighting used to obtain composite life statistics for a group plant account. A depreciation technique (*e.g.*, remaining-life) describes the life statistic used in the system.

With the exception of intangible plant and selected general support asset categories for which amortization accounting has been adopted, Hydro One Networks is currently using a depreciation system composed of the straight-line method, vintage group procedure, and remaining-life technique. Amortization accounting is used for plant categories in which the unit cost of plant items is small in relation to the number of units classified in the account. Plant is retired (*i.e.*, credited to plant and

charged to the reserve) as each vintage achieves an age equal to the amortization period.

Depreciation theory provides that the cost of an asset (or group of assets) should be allocated to operations over an estimate of the economic life of the asset in proportion to the consumption of service potential. It is the opinion of Foster Associates that the objectives of depreciation accounting are being achieved using the currently approved vintage-group procedure, which distinguishes service lives among vintages, and the remaining-life technique, which provides cost apportionment over the estimated weighted-average remaining life of a rate category. It is also the opinion of Foster Associates that amortization accounting remains appropriate for BU 210 general plant amortization categories summarized in Table 1 below.

Account Number	Description	Amortization Period
A	B	C
1610	Computer Software	10 yrs.
1925	Computer Software - Major	6 yrs.

**Table 1. Amortization Accounts**

### Recommended Depreciation Rates

Table 2 below provides a summary of the changes in annual rates and accruals resulting from the 2017 review of Hydro One Networks' Transmission Operations (BU 210).

Function	Accrual Rate			2017 Annualized Accrual		
	Current	Proposed	Difference	Current	Proposed	Difference
A	B	C	D=C-B	E	F	G=F-E
Intangible	9.49%	9.49%	0.00%	\$ 156,907	\$ 156,907	\$ -
Transmission	1.81%	1.83%	0.02%	257,212,511	259,248,891	2,036,380
General Plant	5.23%	4.60%	-0.63%	53,451,933	47,072,433	(6,379,500)
Total	2.04%	2.02%	-0.02%	\$ 310,821,351	\$ 306,478,231	\$ (4,343,120)

**Table 2. Transmission Operations**

The composite accrual rate recommended for Transmission Operations is 2.04 percent. The current equivalent rate is also 2.02 percent. The recommended change in the composite depreciation rate is a reduction of 0.02 percentage points.

A continued application of current rates would provide annualized depreciation expense of \$310,821,351 compared with an annualized expense of \$306,478,231 using the recommended rates. The resulting 2017 expense reduction of \$4,343,120 is largely attributable to rebalancing depreciation reserves for amortizable accounts classified in both general and intangible plant functions. The re-alignment of reserves is designed to produce reserve balances equal to plant balances when each vintage achieves an age equal to the adopted amortization periods.

*Study Procedure*

# STUDY PROCEDURE

## INTRODUCTION

The purpose of a depreciation study is to analyze the mortality characteristics, net salvage rates and adequacy of the depreciation accrual and recorded depreciation reserve for each rate category. The 2017 review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Networks for Transmission Operations. The recommended rates are subject to approval by the Ontario Energy Board.

## SCOPE

The steps involved in conducting the 2017 depreciation review can be grouped into four major tasks:

- Data Collection;
- Life Analysis and Estimation;
- Depreciation Reserve Analysis; and
- Development of Accrual Rates.

The scope of the 2017 review included a consideration of each of these tasks as described below.

## DATA COLLECTION

The minimum database required to conduct a statistical life study consists of a history of vintage year additions and unaged activity–year retirements, transfers and adjustments. These data must be appropriately adjusted for transfers, sales and other plant activity that would otherwise bias the measured service life of normal retirements. The age distribution of surviving plant for unaged data can be estimated by distributing plant in service at the beginning of the study year to prior vintages in proportion to the theoretical amount surviving from a projection or survivor curve identified in the life study. The statistical methods of life analysis used to examine unaged plant data are known as *semi-actuarial techniques*.

A far more extensive database is required to apply statistical methods of life analysis known as *actuarial techniques*. Plant data used in an actuarial life study most often include age distributions of surviving plant at the beginning of a study year and the vintage year, activity year, and dollar amounts associated with normal retirements, reimbursed retirements, sales, abnormal retirements, transfers, corrections, and extraordinary adjustments over a series of prior activity years. An actuarial database may include age distributions of surviving plant at the beginning of the earliest activity year, rather than at the beginning of the study year. Plant additions, however, must be included in a database containing an opening age distribution to derive aged survivors at the beginning of the study year. All activity year transactions with vintage year identification are coded and stored in a database. These data are processed by a computer program and transaction summary reports are created in a format reconcilable to official plant records. The availability of such

detailed information is dependent upon an accounting system that supports aged property records. The Continuing Property Record (CPR) system used by Hydro One Networks provides aged transactions for all plant accounts.

Prior to 1998, plant accounting records were maintained by Hydro One Networks in a legacy Fixed Asset Management System (FAMS) developed by Ontario Hydro. FAMS was replaced with an SAP system in 1998. The SAP system was replaced with a PeopleSoft asset accounting system in 2000. The PeopleSoft system was configured with the asset categories maintained in the SAP system and uploaded with age distributions of surviving plant at December 31, 1999.<sup>1</sup> The PeopleSoft system was replaced in August 2009 by an updated version of the SAP system.

Plant and reserve data used in conducting the 2017 depreciation review were assembled and initially coded by Hydro One Networks personnel. Additional coding was provided by Foster Associates as needed. Plant accounting transactions recorded between January 1, 2015 and December 31, 2016 were extracted from the SAP system, coded and appended to the database used in conducting the 2015 review. An additional dataset of category plant balances at December 31, 2016 was assembled and reconciled to aggregate USoA balances. (See Statement E).

Age distributions of surviving plant (*i.e.*, plant surviving by vintage year of placement) at December 31, 2016 were derived by Foster Associates from the vintaged plant transactions and reconciled to age distributions provided by Hydro One Networks. The complexity of the process through which the database was compiled and mapped to USoA plant categories prevented Foster Associates from reconciling the database to any public reports of Hydro One Networks. The integrity of the assembled database, however, was confirmed by the Company.

## **LIFE ANALYSIS AND ESTIMATION**

Life analysis and life estimation are terms used to describe a two-step procedure for estimating the mortality characteristics of a plant category. The first step (*i.e.*, life analysis) is largely mechanical and primarily concerned with history. Statistical techniques are used in this step to obtain a mathematical description of the forces of retirement acting upon a plant category and an estimate of the *projection life* of the account. Mathematical expressions used to describe these life characteristics are known as *survival functions* or *survivor curves*.

The second step (*i.e.*, life estimation) is concerned with predicting the expected remaining life of property units still exposed to forces of retirement. It is a process

---

<sup>1</sup>In 2003, Hydro One undertook a two-phase project to a) map asset categories maintained in PeopleSoft to USoA plant classifications; and b) align quantities maintained in a Power System Data Base (PSDB) to the re-mapped USoA account classifications. The PSDB provides property unit identification and quantities associated with investments maintained in PeopleSoft. Asset categories maintained in SAP were not mapped to USoA plant account classifications. This limitation prohibited using pre-2000 plant accounting activity in the 2017 depreciation review.

of blending the results of a life analysis with informed judgment (including expectations about the future) to obtain an appropriate projection life and curve descriptive of the parent population from which a plant account is viewed as a random sample. The amount of weight given to a life analysis will depend upon the extent to which past retirement experience is considered predictive of the future.

The analytical methods used in a life analysis are broadly classified as actuarial and semi-actuarial techniques. Actuarial techniques can be applied to plant accounting records that reveal the age of a plant asset at the time of its retirement from service. Stated differently, each retirement unit must be identifiable by date of installation and age at retirement. Semi-actuarial techniques can be used to derive service life and dispersion estimates when age identification of retirements is not maintained or readily available.

An actuarial life analysis program designed and developed by Foster Associates was employed in this review. The first step in an actuarial analysis involves a systematic treatment of the available data for the purpose of constructing an observed life table. A complete life table contains the life history of a group of property units installed during the same accounting period and various probability relationships derived from the data. A life table is arranged by age-intervals (usually defined as one year) and shows the number of units (or dollars) entering and leaving each age-interval and probability relationships associated with this activity. A life table minimally shows the age of each survivor and the age of each retirement from a group of units installed in a given accounting year.

A life table can be constructed in any one of at least five methods. The annual-rate or retirement-rate method was used in this review. The mechanics of the annual-rate method require the calculation of a series of ratios obtained by dividing the number of units (or dollars) surviving at the beginning of an age interval into the number of units (or dollars) retired during the same interval. This ratio—called a “retirement ratio”—is an estimator of the hazard rate or conditional probability of retirement during an age interval. The cumulative proportion surviving is obtained by multiplying the retirement ratio for each age interval by the proportion of the original group surviving at the beginning of that age interval and subtracting this product from the proportion surviving at the beginning of the same interval. The annual-rate method is applied to multiple groups or vintages by combining the retirements and/or survivors of like ages for each vintage included in the analysis.

The second step in an actuarial analysis involves graduating or smoothing the observed life table and fitting the smoothed series to a family of survival functions. The functions used in this review are the Iowa-type curves which are mathematically described by the Pearson frequency curve family. Observed life tables were smoothed by a weighted least-squares procedure in which first, second and third degree orthogonal polynomials were fitted to the observed retirement ratios. The

resulting function was expressed as a survivorship function and numerically integrated to obtain an estimate of the projection life. The observed proportions surviving were then fitted by a weighted least-squares procedure to the Iowa-curve family to obtain a mathematical description or classification of the dispersion characteristics of the data.

The set of computer programs used in this review provides multiple rolling-band, shrinking-band and progressive-band analyses of an account. Observation bands are defined by the dimensions of a "retirement era" that restricts the analysis to the retirement activity of all vintages represented by survivors at the beginning of a selected era. In a rolling-band analysis, a year of retirement experience is added to each successive retirement band and the earliest year from the preceding band is dropped. A shrinking-band analysis begins with the total retirement experience available and the earliest year from the preceding band is dropped for each successive band. A progressive-band analysis adds a year of retirement activity to a previous band without dropping earlier years from the analysis. Rolling, shrinking and progressive band analyses are used to detect the emergence of trends in the behavior of the dispersion and projection life.

Options available in the actuarial life analysis program designed and developed by Foster Associates include the width and location of both placement and observation bands; the interval of years included in a selected band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated. The program also provides both tabular and graphics output to aid in the analysis.

As noted above, the database for Hydro One Networks contains plant accounting transactions for activity years 2000–2016. While it is theoretically possible to obtain life indications from an actuarial analysis of a single activity year, retirements during the year must be widely distributed over the beginning-of-year surviving vintages of a nearly mature plant account.<sup>2</sup> A similar limitation applies to the database of Hydro One Networks which contains minimal retirement activity during the available activity years. Retirements must be sufficiently distributed across vintages within these years in order to obtain meaningful service life indications from a statistical analysis.

Life tables were constructed for each USoA plant account for which retirements were recorded over the period 2000–2016. Life tables constructed over this limited historical period exhibited uniformly high degrees of censoring and indeterminate

---

<sup>2</sup>Plant maturity is achieved when the age distribution of surviving plant resembles a complete survivor curve descriptive of the forces of retirement acting upon the plant category.

measurements of service life. These results were directly attributable to an insufficient distribution of retirements over the available band of activity years.

As was noted in the 2015 review, limitations in conducting life analyses were also imposed by vintage years “banded” by the Company in 1992 and again in 1998 when age distributions from a Fixed Asset Management System (FAMS) were uploaded to SAP. All pre-1950 vintages were assigned a vintage year of 1950. Plant installed between 1951 and 1955 was assigned a vintage year of 1955. Similarly, plant installed during the intervals 1956–1960, 1961–1965 and 1966–1970 were assigned vintage years 1960, 1965 and 1970, respectively. Although discontinued in 1971, the banding of pre-1970 vintages will continue to produce unreliable life indications until most of the earlier vintages have been retired from service.

Pending the availability of sufficient or normal retirement activity to conduct service life studies, it is the opinion of Foster Associates that a composite of the parameters estimated for the asset categories recorded in a USoA account provides the best available estimate of service life statistics for the current depreciation review.

### Class/Category Service Lives

Class categories used in the 2017 review are those established in 2008 in preparation for implementation of International Financial Reporting Standards (IFRS). While Hydro One Networks has received an exemption from an otherwise mandatory adoption of IFRS for rate regulated entities, the Company intends to continue maintaining category classifications for engineering operations and business planning purposes.

The review of category lives undertaken in the 2013 review included onsite meetings with Company engineers, accountants and other subject matter experts having managerial responsibilities for the assets under review. Meetings of the project team were facilitated by Foster Associates. Discussions were held with representatives from planning, operations, maintenance, information technology and facilities to assess the reasonableness of proposed category lives within their respective areas of expertise. Consideration was also given to the range of service lives recommended in the Asset Amortization Study prepared for the Ontario Energy Board by Kinectrics Inc.

Category lives were reviewed in the 2015 and current study via written surveys distributed to the subject matter experts who participated in the 2013 review. Each participant was asked to revisit currently approved category lives within their respective areas of expertise and to document reasons for any suggested changes or adjustments. No adjustments were recommended by these participants. Accordingly, category lives recommended and approved in the 2015 review were retained in the 2017 review.

## USoA Service Lives

Proposed projection lives for USoA categories were derived from harmonic weighting of the constituent category lives recommended by the project team. Iowa survivor curves considered descriptive of the forces of retirement acting upon each USoA category were selected by Foster Associates based on experience and an understanding of the parametric form of the associated probability density functions. Projection lives and projection curves recommended for all depreciable USoA categories are summarized in Statement E.

## **DEPRECIATION RESERVE ANALYSIS**

The purpose of a depreciation reserve analysis is to compare the current level of recorded reserves with the level required to achieve the goals or objectives of depreciation accounting if the amount and timing of future retirements and net salvage are realized as predicted. The difference between a required (or theoretical) depreciation reserve and a recorded reserve provides a measurement of the expected excess or shortfall that will remain in the depreciation reserve if corrective action is not taken to eliminate the reserve imbalance.

Unlike a recorded reserve which represents the net amount of depreciation expense charged to previous periods of operations, a theoretical reserve is a measure of the implied reserve requirement at the beginning of a study year if the timing of future retirements and net salvage is in exact conformance with a survivor curve chosen to predict the probable life of property still exposed to the forces of retirement. Stated differently, a theoretical depreciation reserve is the difference between the recorded cost of plant currently in service and the sum of depreciation expense and net salvage that will be charged in the future if retirements are distributed over time according to a specified retirement frequency distribution.<sup>3</sup>

Survivor curves used in the calculation of a theoretical depreciation reserve are intended to describe forces of retirement that will be operative in the future. However, retirements caused by forces such as accidents, physical deterioration and changing technology seldom, if ever, remain stable over time. It is unlikely, therefore, that a probability or retirement frequency distribution can be identified that will accurately describe the age of plant retirements over the complete life cycle of a vintage. It is for this reason that depreciation rates should be reviewed periodically and adjusted for observed or expected changes in the parameters chosen to describe the underlying forces of mortality.

Although reserve records are commonly maintained by various account classifications, the total recorded reserve in relation to the sum of account computed reserves provides a meaningful indicator of the adequacy (or inadequacy) of recorded reserves. If statistical life studies have not been conducted or retirement dispersion

---

<sup>3</sup>Hydro One Networks does not accrue for net salvage.

has been ignored in setting depreciation rates, it is likely that some accounts will be over-depreciated and other accounts will be under-depreciated relative to a calculated or theoretical reserve. Differences between theoretical and recorded reserves will also arise as a normal occurrence when service lives, dispersion patterns and net salvage estimates are adjusted in the course of depreciation reviews. Differences can also arise from plant accounting activity such as transfers and adjustments that may require an identification of reserves at a level lower than maintained in the accounting system. It is appropriate, therefore, and consistent with group depreciation theory to periodically redistribute or rebalance recorded reserves among primary accounts based upon the most recent estimates of retirement dispersion and net salvage rates.

It is the opinion of Foster Associates that a redistribution of recorded reserves is appropriate for Hydro One Networks at this time. Offsetting reserve imbalances attributable to the passage of time should be realigned among primary accounts to reduce offsetting imbalances and increase depreciation rate stability.

With the exception of amortizable categories in which theoretical or computed reserves replace recorded reserves, all remaining reserves were redistributed by multiplying the calculated reserve for each USoA primary account by the ratio of the sum of recorded reserves to the sum of calculated reserves. The sum of redistributed reserves is, therefore, equal to the sum of recorded depreciation reserves before the redistribution.

Statement C provides a comparison of recorded, computed and rebalanced reserves for Transmission Operations (BU 210) at December 31, 2016. The recorded reserve was \$5,559,043,476 or 36.6 percent of the depreciable plant investment. The corresponding computed reserve is \$5,002,644,977 or 32.9 percent of the depreciable plant investment. A proportionate amount of the measured reserve imbalance of \$556,398,499 will be amortized over the composite weighted-average remaining life of each rate category using the remaining life depreciation rates proposed in this review.

### **DEVELOPMENT OF ACCRUAL RATES**

The goal or objective of depreciation accounting is cost allocation over the economic life of an asset in proportion to the consumption of service potential. Ideally, the cost of an asset—which represents the cost of obtaining a bundle of service units—should be allocated to future periods of operation in proportion to the amount of service potential expended during an accounting interval. The service potential of an asset is the present value of future net revenue (*i.e.*, revenue less expenses exclusive of depreciation and other non-cash expenses) or cash inflows attributable to the use of that asset alone.

Cost allocation in proportion to the consumption of service potential is often approximated by the use of depreciation methods employing time rather than net revenue as the apportionment base. Examples of time-based methods include sinking-fund, straight-line, declining balance, and sum-of-the-years' digits. The advantage of a time-based method is that it does not require an estimate of the remaining amount of service potential an asset will provide or the amount of potential consumed during an accounting interval. Using a time-based allocation method, however, does not change the goal of depreciation accounting. If it is reasonable to predict that the net revenue pattern of an asset will either decrease or increase over time, then an accelerated or decelerated time-based method should be used to approximate the rate at which service potential is actually consumed.

The time period over which the cost of an asset will be allocated to operations is determined by the combination of a procedure and a technique. A depreciation procedure describes the level of grouping or sub-grouping of assets within a plant category. Broad group, vintage group, equal-life group, and item (or unit) are a few of the more widely used procedures. A depreciation technique describes the life statistic used in a depreciation system. Whole life and remaining life (or expectancy) are the most common techniques.

Depreciation rates recommended in the 2017 review were developed using the currently approved system composed of the straight-line method, vintage group procedure, and remaining-life technique. It is the opinion of Foster Associates that this system will remain appropriate for Hydro One Networks, provided depreciation reviews are conducted periodically and parameters are routinely adjusted to reflect changing operating conditions.

It is also the opinion of Foster Associates that amortization accounting currently approved for selected general support asset accounts is consistent with the goals and objectives of depreciation accounting derived from cost allocation and depreciation accounting theory.

The treatment of amortization accounts in the current and prior depreciation reviews was designed to produce annualized accruals equivalent to applying a rate equal to the reciprocal of an amortization period to plant balances after retirements have been recorded. Applying a rate equal to the reciprocal of the amortization period to plant balances prior to posting retirements would overstate the annualized amortization expense. Accrual rates contained in Statement A have been applied to plant balances containing vintages that will be retired upon approval of the 2017 review. Accrual rates contained in Statement A should be applied to current plant balances. Accrual rates equal to the reciprocal of the amortization periods (Statement D, Column H) should be applied to these categories after plant balances have been reduced by all vintages that have achieved an age equal to the amortization period.

*Statements*

# STATEMENTS

## INTRODUCTION

This section provides a comparative summary of depreciation rates, annual depreciation accruals, recorded, computed and redistributed depreciation reserves, and current and recommended service life statistics for Hydro One Networks Transmission Operations. The content of these statements is briefly described below.

- Statement A provides a comparative summary of current and recommended annual depreciation rates using the vintage group procedure, remaining-life technique.
- Statement B provides a comparison of current and recommended annualized 2017 depreciation accruals derived from the depreciation rates contained in Statement A.
- Statement C provides a comparison of recorded, computed and redistributed reserves for each rate category at December 31, 2016.
- Statement D provides a comparative summary of current and recommended parameters and statistics including projection life, projection curve, average service life and average remaining life.
- Statement E displays the computation of recommended USoA projection lives derived from recommended Category ID lives.

Current depreciation accruals shown on Statements B are the product of the plant investment (Column B) and current depreciation rates shown on Statement A. These are the effective rates used by Hydro One Networks for the mix of investments recorded on December 31, 2016. Similarly, recommended depreciation accruals shown on Statement B are the product of the plant investment and recommended depreciation rates shown on Statement A. Recommended remaining-life accrual rates (Statement A) are given by:

$$\text{Accrual Rate} = \frac{1.0 - \text{Reserve Ratio}}{\text{Remaining Life}}$$

**HYDRO ONE NETWORKS INC. (BU 210)**

Statement A

Comparison of Current and Proposed Accrual Rates

Current: VG Procedure / RL Technique

Proposed: VG Procedure / RL Technique

Account Description A	Current			Proposed			
	Rem. Life B	Net Salvage C	Accrual Rate D	Rem. Life E	Net Salvage F	Reserve Ratio G	Accrual Rate H
<b>INTANGIBLE PLANT</b>							
1610 Computer Software	← 10 Year Amortization →		9.49%	← 10 Year Amortization →			9.49%
<b>Total Intangible Plant</b>			9.49%	3.50		66.80%	9.49%
<b>TRANSMISSION PLANT</b>							
1705D Land - Depreciable	75.60		0.96%	71.60		31.50%	0.96%
1706 Land Rights	74.50		0.96%	70.84		32.31%	0.96%
1708 Buildings and Fixtures	29.81		1.82%	29.96		45.84%	1.81%
1715 Station Equipment	31.16		2.07%	31.40		34.52%	2.09%
1720 Towers and Fixtures	55.36		1.27%	55.00		29.78%	1.28%
1730 Overhead Conductors and Devices	43.16		1.44%	42.45		38.67%	1.44%
1735 Underground Conduit	32.19		1.64%	32.77		45.76%	1.66%
1740 Underground Conductors and Devices	48.99		1.79%	48.25		13.59%	1.79%
1745 Roads and Trails	30.50		1.79%	30.73		44.52%	1.81%
<b>Total Transmission Plant</b>			1.81%	35.72		34.76%	1.83%
<b>GENERAL PLANT</b>							
<b>Depreciable</b>							
1905D Land - Depreciable	79.48		0.98%	75.48		27.72%	0.96%
1908 Buildings and Fixtures	27.36		2.10%	25.72		49.10%	1.98%
1910 Leasehold Improvements	1.00		-2.39%	1.00		108.41%	-8.41%
1922 Computer Hardware - Major	2.11		6.12%	7.15		42.98%	7.97%
1955 Communication Equipment	12.05		4.60%	10.84		54.94%	4.16%
1980 System Supervisory Equipment	5.09		6.78%	5.03		71.08%	5.75%
<b>Total Depreciable</b>			5.28%	8.13		61.14%	4.65%
<b>Amortizable</b>							
1925 Computer Software - Major	← 6 Year Amortization →		0.05%	← 6 Year Amortization →			0.05%
<b>Total Amortizable</b>			0.05%	1.00		99.95%	0.05%
<b>Total General Plant</b>			5.23%	7.94		61.49%	4.60%
<b>TOTAL TRANSMISSION OPERATIONS</b>			2.04%	30.77		36.56%	2.02%

**HYDRO ONE NETWORKS INC. (BU 210)**

Statement B

Comparison of Current and Proposed Accruals  
 Current: VG Procedure / RL Technique  
 Proposed: VG Procedure / RL Technique

Account Description A	12/31/16 Plant Investment B	2017 Annualized Accrual		
		Current C	Proposed D	Difference E=D-C
<b>INTANGIBLE PLANT</b>				
1610 Computer Software	\$ 1,654,200	\$ 156,907	\$ 156,907	\$ -
<b>Total Intangible Plant</b>	<b>\$ 1,654,200</b>	<b>\$ 156,907</b>	<b>\$ 156,907</b>	<b>\$ -</b>
<b>TRANSMISSION PLANT</b>				
1705D Land - Depreciable	\$ 971,630	\$ 9,328	\$ 9,328	\$ -
1706 Land Rights	239,932,927	2,303,356	2,303,356	
1708 Buildings and Fixtures	466,096,738	8,482,961	8,436,351	(46,610)
1715 Station Equipment	8,636,051,657	178,766,269	180,493,480	1,727,211
1720 Towers and Fixtures	2,406,248,912	30,559,361	30,799,986	240,625
1730 Overhead Conductors and Devices	1,705,696,951	24,562,036	24,562,036	
1735 Underground Conduit	310,594,051	5,093,742	5,155,861	62,119
1740 Underground Conductors and Devices	150,212,155	2,688,798	2,688,798	
1745 Roads and Trails	265,176,530	4,746,660	4,799,695	53,035
<b>Total Transmission Plant</b>	<b>\$ 14,180,981,551</b>	<b>\$ 257,212,511</b>	<b>\$ 259,248,891</b>	<b>\$ 2,036,380</b>
<b>GENERAL PLANT</b>				
<b>Depreciable</b>				
1905D Land - Depreciable	\$ 3,246,825	\$ 31,819	\$ 31,170	\$ (649)
1908 Buildings and Fixtures	121,382,983	2,549,043	2,403,383	(145,660)
1910 Leasehold Improvements	100,228	(2,395)	(8,429)	(6,034)
1922 Computer Hardware - Major	14,388,081	880,551	1,146,730	266,179
1955 Communication Equipment	425,285,133	19,563,116	17,691,862	(1,871,254)
1980 System Supervisory Equipment	448,745,857	30,424,969	25,802,887	(4,622,082)
<b>Total Depreciable</b>	<b>\$ 1,013,149,107</b>	<b>\$ 53,447,103</b>	<b>\$ 47,067,603</b>	<b>\$ (6,379,500)</b>
<b>Amortizable</b>				
1925 Computer Software - Major	\$ 9,293,454	\$ 4,830	\$ 4,830	\$ -
<b>Total Amortizable</b>	<b>\$ 9,293,454</b>	<b>\$ 4,830</b>	<b>\$ 4,830</b>	<b>\$ -</b>
<b>Total General Plant</b>	<b>\$ 1,022,442,561</b>	<b>\$ 53,451,933</b>	<b>\$ 47,072,433</b>	<b>\$ (6,379,500)</b>
<b>TOTAL TRANSMISSION OPERATIONS</b>	<b>\$ 15,205,078,312</b>	<b>\$ 310,821,351</b>	<b>\$ 306,478,231</b>	<b>\$ (4,343,120)</b>

**HYDRO ONE NETWORKS INC. (BU 210)**

Depreciation Reserve Summary  
Vintage Group Procedure  
December 31, 2016

Statement C

Account Description	Plant		Recorded Reserve		Computed Reserve		Redistributed Reserve	
	Investment	Ratio	Amount	Ratio	Amount	Ratio	Amount	Ratio
A	B		C		E		G	
	D=C/B		F=E/B		H=G/B			
<b>INTANGIBLE PLANT</b>								
1610 Computer Software	\$ 1,654,200	100.00%	\$ 1,654,200	100.00%	\$ 1,105,026	66.80%	\$ 1,105,026	66.80%
<b>Total Intangible Plant</b>	\$ 1,654,200	100.00%	\$ 1,654,200	100.00%	\$ 1,105,026	66.80%	\$ 1,105,026	66.80%
<b>TRANSMISSION PLANT</b>								
1705D Land - Depreciable	\$ 971,630	25.80%	\$ 250,722	25.80%	\$ 275,943	28.40%	\$ 306,016	31.50%
1706 Land Rights	239,932,927	24.55%	58,909,391	24.55%	69,913,436	29.14%	77,532,860	32.31%
1708 Buildings and Fixtures	466,096,738	48.97%	228,254,822	48.97%	192,663,053	41.34%	213,660,184	45.84%
1715 Station Equipment	8,636,051,657	34.00%	2,935,974,877	34.00%	2,687,992,389	31.13%	2,980,939,714	34.52%
1720 Towers and Fixtures	2,406,248,912	33.82%	813,816,505	33.82%	646,125,356	26.85%	716,542,481	29.78%
1730 Overhead Conductors and Devices	1,705,696,951	36.16%	616,791,688	36.16%	594,821,904	34.87%	659,647,789	38.67%
1735 Underground Conduit	310,594,051	32.65%	101,416,305	32.65%	128,156,929	41.26%	142,123,944	45.76%
1740 Underground Conductors and Devices	150,212,155	11.60%	17,426,597	11.60%	18,411,164	12.26%	20,417,681	13.59%
1745 Roads and Trails	265,176,530	58.97%	156,384,211	58.97%	106,452,830	40.14%	118,054,452	44.52%
<b>Total Transmission Plant</b>	\$ 14,180,981,551	34.76%	\$ 4,929,225,120	34.76%	\$ 4,444,813,004	31.34%	\$ 4,929,225,120	34.76%
<b>GENERAL PLANT</b>								
<b>Depreciable</b>								
1905D Land - Depreciable	\$ 3,246,825	26.87%	\$ 872,391	26.87%	\$ 795,386	24.50%	\$ 899,977	27.72%
1908 Buildings and Fixtures	121,382,983	44.04%	53,462,311	44.04%	52,677,650	43.40%	59,604,592	49.10%
1910 Leasehold Improvements	100,228	90.92%	91,131	90.92%	96,031	95.81%	108,659	108.41%
1922 Computer Hardware - Major	14,388,081	31.03%	4,465,188	31.03%	5,465,724	37.99%	6,184,449	42.98%
1955 Communication Equipment	425,285,133	53.68%	228,274,441	53.68%	206,486,327	48.55%	233,638,617	54.94%
1980 System Supervisory Equipment	448,745,857	73.93%	331,755,908	73.93%	281,917,205	62.82%	318,988,413	71.08%
<b>Total Depreciable</b>	\$ 1,013,149,107	61.09%	\$ 618,921,370	61.09%	\$ 547,438,323	54.03%	\$ 619,424,706	61.14%
<b>Amortizable</b>								
1925 Computer Software - Major	\$ 9,293,454	99.45%	\$ 9,242,786	99.45%	\$ 9,288,624	99.95%	\$ 9,288,624	99.95%
<b>Total Amortizable</b>	\$ 9,293,454	99.45%	\$ 9,242,786	99.45%	\$ 9,288,624	99.95%	\$ 9,288,624	99.95%
<b>Total General Plant</b>	\$ 1,022,442,561	61.44%	\$ 628,164,156	61.44%	\$ 556,726,947	54.45%	\$ 628,713,330	61.49%
<b>TOTAL TRANSMISSION OPERATIONS</b>	\$ 15,205,078,312	36.56%	\$ 5,559,043,476	36.56%	\$ 5,002,644,977	32.90%	\$ 5,559,043,476	36.56%

**HYDRO ONE NETWORKS INC. (BU 210)**

Current and Proposed Parameters  
Vintage Group Procedure

Statement D

Account Description A	Current Parameters						Proposed Parameters					
	B	C	D	E	F	G	H	I	J	K	L	M
	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.	P-Life/ AYFR	Curve Shape	VG ASL	Rem. Life	Avg. Sal.	Fut. Sal.
<b>INTANGIBLE PLANT</b>												
1610 Computer Software	10.00	SQ	10.00	7.19			10.00	SQ	10.00	3.50		
<b>Total Intangible Plant</b>									<b>10.00</b>	<b>3.50</b>		
<b>TRANSMISSION PLANT</b>												
1705D Land - Depreciable	100.00	S6	100.00	75.60			100.00	S6	100.00	71.60		
1706 Land Rights	100.00	S6	99.98	74.50			100.00	S6	99.97	70.84		
1708 Buildings and Fixtures	50.00	S6	50.29	29.81			50.00	S6	51.07	29.96		
1715 Station Equipment	45.00	S2	45.56	31.16			45.00	S2	45.59	31.40		
1720 Towers and Fixtures	75.00	S2	75.17	55.36			75.00	S2	75.19	55.00		
1730 Overhead Conductors and Devices	65.00	S3	65.15	43.16			65.00	S3	65.18	42.45		
1735 Underground Conduit	55.00	S2	55.60	32.19			55.00	S2	55.79	32.77		
1740 Underground Conductors and Devices	55.00	S2	55.00	48.99			55.00	S2	54.99	48.25		
1745 Roads and Trails	50.00	S2	51.14	30.50			50.00	S2	51.34	30.73		
<b>Total Transmission Plant</b>									<b>52.02</b>	<b>35.72</b>		
<b>GENERAL PLANT</b>												
<b>Depreciable</b>												
1905D Land - Depreciable	100.00	S6	99.98	79.48			100.00	S6	99.97	75.48		
1908 Buildings and Fixtures	45.00	S4	45.27	27.36			45.00	S4	45.44	25.72		
1910 Leasehold Improvements	10.00	S6	19.88	1.00			10.00	S6	23.88	1.00		
1922 Computer Hardware - Major	10.00	S6	10.97	2.11			10.00	S6	11.53	7.15		
1955 Communication Equipment	20.00	L2	20.54	12.05			20.00	L2	21.07	10.84		
1980 System Supervisory Equipment	10.00	L2	12.97	5.09			10.00	L2	13.53	5.03		
<b>Total Depreciable</b>									<b>17.68</b>	<b>8.13</b>		
<b>Amortizable</b>												
1925 Computer Software - Major	6.00	SQ	6.00	2.11			6.00	SQ	6.00	1.00		
<b>Total Amortizable</b>									<b>6.00</b>	<b>1.00</b>		
<b>Total General Plant</b>									<b>17.37</b>	<b>7.94</b>		
<b>TOTAL TRANSMISSION OPERATIONS</b>									<b>45.85</b>	<b>30.77</b>		

**HYDRO ONE NETWORKS INC. (BU 210)**

Statement E

Asset Category Summary  
December 31, 2016  
Harmonic Weighting

Description A	Current P-Life		Proposed P-Life		Plant	
	USoA B	Category C	USoA D	Category E	USoA F	Category G
<b>INTANGIBLE PLANT</b>						
<b>1610 Computer Software</b>						
1657 GENRL -ADM & SERV-SYS SOFTWARE		10		10		\$ 1,654,200
<b>Total USoA 1610</b>	10 SQ	10	10 SQ	10	\$ 1,654,200	\$ 1,654,200
<b>TRANSMISSION PLANT</b>						
<b>1705D Land - Depreciable</b>						
1210 LAND PURCH & ACQUI (OLD CAP)		100		100		\$ 971,630
<b>Total USoA 1705D</b>	100 S6	100	100 S6	100	\$ 971,630	\$ 971,630
<b>1706 Land Rights</b>						
1111 RIGHTS & EASMNTS <LANDSCAPING>		100		100		\$ 2,811,500
1212 EASMNTS & RIGHTS		100		100		237,121,428
<b>Total USoA 1706</b>	100 S6	100	100 S6	100	\$ 239,932,927	\$ 239,932,927
<b>1708 Buildings and Fixtures</b>						
1120 STN BUILDINGS COMPONENTS		50		50		\$ 404,367,186
1121 CRANES&HOISTS IN BLDGS		50		50		4,865,443
1260 BLDG W U/G CABLE		50		50		31,325,308
1270 SERV STRUCTURES		50		50		25,538,801
<b>Total USoA 1708</b>	50 S6	50	50 S6	50	\$ 466,096,738	\$ 466,096,738
<b>1715 Station Equipment</b>						
1111 RIGHTS & EASMNTS <LANDSCAPING>		50		50		\$ 312
1112 LANDSCAPING		50		50		25,518,088
1113 SITE IMPRV-EXCL FENCE		50		50		370,196,484
1123 COST EQUIP FOUNDATIONS		65		65		607,580,584
1127 STEEL/PIPE STRUC FOR SWITCH EQ		65		65		417,224,493
1128 FENCES		30		30		137,928,328
1150 ROT ELEC EQP(NO WIND'G)		65		65		16,006,744
1151 ROT ELEC EQP(WIND'GS)		65		65		301,966
1152 CAPACITORS		30		30		148,753,722
1155 REGULATORS INCL INSTAL COST		40		40		11,032,923
1159 MOBILE SUB-STATIONS		30		30		191,606
1160 MISC STN EQP-TRSF/VOLT TRSF		40		40		378,051,502
1161 SERV SWG-AC/DC-LIGHT TRSF		55		55		244,964,515
1162 CONTROL CABLE&CONDUIT		60		60		424,282,721
1163 GROUNDING SYSTEMS		60		60		217,098,395
1164 METERING UNITS		15		15		59,243,862
1166 SWITCHBOARDS		35		35		734,733,045
1167 SUP CNTRL- PRIM H/WARE & SYS		20		20		595,361,798
1168 SUP CNTRL - PRIM APPL S/WARE		20		20		19,427,874
1170 SERVICE SYSTEMS		50		50		204,784,932
1175 TRANSF<=50KV OR <5MVA		50		50		67,501,974
1176 TRNSF<=115KV OR >5MVA		50		50		392,469,591
1177 TRANSF <=230KV		50		50		454,306,174
1178 TRANSF >230KV		50		50		324,267,869
1179 TRANSF INSTAL COST		50		50		347,215,661
1181 SWITCHING >=34.5KV		45		45		207,808,962
1182 SWITCHING >=115KV		45		45		144,503,012
1183 SWITCHING >=230KV		45		45		158,852,466
1184 SF6 SWITCHGEAR		45		45		405,853,032
1185 RECLOSERS		40		40		1,538,864
1186 MISC SWITCHING		45		45		194,758,426
1187 BUS (RIGID & STRAIN)		45		45		317,259,318
1188 CABLE		45		45		128,526,978
1190 CCT BREAKERS >=230KV		45		45		301,218,220
1191 CCT BREAKERS >=115KV		45		45		121,321,257
1192 CCT BREAKERS <115KV		45		45		156,774,086
1193 CCT BREAKERS INSTALL		45		45		218,680,672
1194 ENCLD SWGR (ALL COMPNT)		45		45		80,511,200
<b>Total USoA 1715</b>	45 S2	42	45 S2	42	\$ 8,636,051,657	\$ 8,636,051,657

**HYDRO ONE NETWORKS INC. (BU 210)**

Statement E

Asset Category Summary  
December 31, 2016  
Harmonic Weighting

Description A	Current P-Life		Proposed P-Life		Plant	
	USoA B	Category C	USoA D	Category E	USoA F	Category G
<b>1720 Towers and Fixtures</b>						
1230 STEEL TWR, SUP&FTNG		90		90		\$ 1,588,032,050
1240 POLES INCL XARM,GUY,ANCHR		50		50		709,211,731
1245 STEEL POLES		90		90		100,967,337
1249 COMPOSITE POLES		80		80		8,037,793
<b>Total USoA 1720</b>	<b>75 S2</b>	<b>73</b>	<b>75 S2</b>	<b>73</b>	<b>\$ 2,406,248,912</b>	<b>\$ 2,406,248,912</b>
<b>1730 Overhead Conductors and Devices</b>						
1220 INSULATORS		60		60		\$ 329,068,237
1232 GROUNDING SYSTEM		50		50		152,956,518
1235 OPT GRND WIRE		50		50		60,659,868
1250 OVERHD CONDUCTOR ALL		70		70		1,081,139,761
1252 SWITCHES&DEVCE		60		60		41,394,209
1254 RETENSION COSTS		60		60		40,478,358
<b>Total USoA 1730</b>	<b>65 S3</b>	<b>64</b>	<b>65 S3</b>	<b>64</b>	<b>\$ 1,705,696,951</b>	<b>\$ 1,705,696,951</b>
<b>1735 Underground Conduit</b>						
1220 INSULATORS		55		55		\$ 140,166
1261 UGRD CONDUIT		55		55		310,453,884
<b>Total USoA 1735</b>	<b>55 S2</b>	<b>55</b>	<b>55 S2</b>	<b>55</b>	<b>\$ 310,594,051</b>	<b>\$ 310,594,051</b>
<b>1740 Underground Conductors and Devices</b>						
1262 UGRD CONDUCTOR		55		55		\$ 150,212,155
<b>Total USoA 1740</b>	<b>55 S2</b>	<b>55</b>	<b>55 S2</b>	<b>55</b>	<b>\$ 150,212,155</b>	<b>\$ 150,212,155</b>
<b>1745 Roads and Trails</b>						
1122 PERM RDS & SURFC AREA		25		25		\$ 57,128,751
1174 RAILWAY TRACK		30		30		8,020,447
1215 CLRNG & OVERBLDNG		70		70		162,135,244
1271 ROADS & TRAILS		70		70		37,892,089
<b>Total USoA 1745</b>	<b>50 S2</b>	<b>49</b>	<b>50 S2</b>	<b>49</b>	<b>\$ 265,176,530</b>	<b>\$ 265,176,530</b>
<b>GENERAL PLANT</b>						
<b>Depreciable</b>						
<b>1905D Land - Depreciable</b>						
1828 GENRL -COMM -SITE IMPROVEMENT		100		100		\$ 3,246,825
<b>Total USoA 1905D</b>	<b>100 S6</b>	<b>100</b>	<b>100 S6</b>	<b>100</b>	<b>\$ 3,246,825</b>	<b>\$ 3,246,825</b>
<b>1908 Buildings and Fixtures</b>						
1612 GENRL-ADM&SERV-LANDSCAPING		50		50		\$ 23,920
1621 GENRL-ADM&SERV_BLD FRAME&MTL		50		50		33,016,917
1622 GENRL -ADM & SERV-RDS&SURFACES		25		25		4,049,783
1623 GENRL-ADM & SERV-BLD FRAME		50		50		14,947,847
1628 GENRL -ADM & SERV-FENCE		30		30		4,126,610
1650 GENRL- ADM & SERV-DISTN SYS		50		50		5,579,469
1663 GENRL -ADM & SERV_AUX EQ BLD		50		50		12,706,717
1813 GENRL -COMM-LANDSCAPING		50		50		62,867
1820 GENRL -COMM - BUILDINGS		50		50		13,855,943
1853 GENRL-COMM-STR&FOOTINGS-POLES		50		50		33,012,910
<b>Total USoA 1908</b>	<b>45 S4</b>	<b>47</b>	<b>45 S4</b>	<b>47</b>	<b>\$ 121,382,983</b>	<b>\$ 121,382,983</b>
<b>1910 Leasehold Improvements</b>						
1624 GENRL -ADM & SERV-BLDGS-LEASED		10		10		\$ 100,228
<b>Total USoA 1910</b>	<b>10 S6</b>	<b>10</b>	<b>10 S6</b>	<b>10</b>	<b>\$ 100,228</b>	<b>\$ 100,228</b>
<b>1922 Computer Hardware - Major</b>						
1653 GENRL-ADM &SERV-LAN ELECT DEV		10		10		\$ 12,728,056
1655 GENRL-ADM & SERV- LAN CABLE		10		10		672,183
1656 GENRL -ADM & SERV-LAN FIB OPT		10		10		987,842
<b>Total USoA 1922</b>	<b>10 S6</b>	<b>10</b>	<b>10 S6</b>	<b>10</b>	<b>\$ 14,388,081</b>	<b>\$ 14,388,081</b>

**HYDRO ONE NETWORKS INC. (BU 210)**

Statement E

Asset Category Summary

December 31, 2016

Harmonic Weighting

Description A	Current P-Life		Proposed P-Life		Plant	
	USoA B	Category C	USoA D	Category E	USoA F	Category G
<b>1955 Communication Equipment</b>						
1654 GENRL-ADM & SERV -TELCM WIRE		7		7	\$	2,594,458
1658 GENRL -ADM & SERV -TELCM EQUIP		7		7		2,269,843
1659 GENRL -ADM & SERV- TELCOM SW		7		7		717,041
1850 GENRL-COMM - RADIO EQUIPMENT		10		10		53,441,497
1854 GENRL -COMM -ADMIN TELCOM EQUIP		7		7		23,032,168
1863 GENRL -COMM -OPTICAL WIRE		25		25		95,420,301
1864 GENRL -COMM - OPT WIRE TERMTN		20		20		158,569,611
1865 GENRL-COMM - OPGW W FIB CABLE		25		25		69,706,247
1870 GENRL -COMM -POWER SUPPLY EQUIP		15		15		19,533,966
<b>Total USoA 1955</b>	20 L2	17	20 L2	17	\$	425,285,133
<b>1980 System Supervisory Equipment</b>						
1840 GENRL -COMM-PWR LINE EQUIP		15		15	\$	171,194,113
1844 GENRL -COMM-SYS CNTRL COMP EQ		6		6		147,529,138
1846 GENRL-COMM-DACS APPL S/WARE		6		6		2,678,368
1847 GENRL -COMM - DACS SYS S/WARE		6		6		98,558,645
1860 GENRL-COMM-POLE		25		25		28,769,384
1864 GENRL -COMM - OPT WIRE TERMTN		20		20		16,209
<b>Total USoA 1980</b>	10 L2	8	10 L2	8	\$	448,745,857
<b>Amortizable</b>						
<b>1925 Computer Software - Major</b>						
1657 GENRL-ADM & SERV-SYS SOFTWARE		6		6	\$	9,293,454
<b>Total USoA 1925</b>	6 SQ	6	6 SQ	6	\$	9,293,454
<b>TOTAL BU 210</b>					\$	15,205,078,312

*Analysis*

# ANALYSIS

## INTRODUCTION

This section provides an explanation of the supporting schedules developed in the Hydro One Networks transmission depreciation review to estimate appropriate projection curves, projection lives and statistics for each rate category. The form and content of the schedules developed for an account depend upon the method of analysis adopted for the category.

This section also includes an example of the supporting schedules developed for Account 1715 – Station Equipment. Documentation for all other plant accounts is contained in the review work papers. The supporting schedules developed in the Hydro One Networks review include:

- Schedule A – Generation Arrangement;
- Schedule B – Age Distribution;
- Schedule C – Plant History;
- Schedule D – Actuarial Life Analysis; and
- Schedule E – Graphics Analysis.

The format and content of these schedules are briefly described below.

### SCHEDULE A – GENERATION ARRANGEMENT

The purpose of this schedule is to obtain appropriate weighted-average life statistics for a rate category. The weighted-average remaining-life is the sum of Column H divided by the sum of Column I. The weighted average life is the sum of Column C divided by the sum of Column I. The following table provides a description of each column in the generation arrangement.

Column	Title	Description
A	Vintage	Vintage or placement year of surviving plant.
B	Age	Age of surviving plant at beginning of study year.
C	Surviving Plant	Actual dollar amount of surviving plant.
D	Average Life	Estimated average life of each vintage. This statistic is the sum of the realized life and the unrealized life, which is the product of the remaining life (Column E) and the theoretical proportion surviving.
E	Remaining Life	Estimated remaining life of each vintage.
F	Net Plant Ratio	Theoretical net plant ratio of each vintage.
G	Allocation Factor	A pivotal ratio which determines the amortization period of the difference between the recorded and computed
H	Computed Net Plant	Plant in service less theoretical reserve for each vintage.
I	Accrual	Ratio of computed net plant (Column H) and remaining life (Column E).

Table 3. Generation Arrangement

### **SCHEDULE B – AGE DISTRIBUTION**

This schedule provides the age distribution and realized life of surviving plant shown in Column C of the Generation Arrangement (Schedule A). The format of the schedule depends upon the availability of either aged or unaged data. Derived additions for vintage years older than the earliest activity year in an account for unaged data are obtained from the age distribution of surviving plant at the beginning of the earliest activity year. The amount surviving from these vintages is shown in Column D. The realized life (Column G) is derived from the dollar years of service provided by a vintage over the period of years the vintage has been in service. Plant additions for vintages older than the earliest activity year in an account are represented by the opening balances shown in Column D.

The computed proportion surviving (Column D) for unaged is derived from a computed mortality analysis. The average service life displayed in the title block is the life statistic derived for the most recent activity year, given the derived age distribution at the start of the year and the specified retirement dispersion. The realized life (Column F) is obtained by finding the slope of an SC retirement dispersion, which connects the computed survivors of a vintage (Column E) to the recorded vintage addition (Column B). The realized life is the area bounded by the SC dispersion, the computed proportion surviving and the age of the vintage.

### **SCHEDULE C – PLANT HISTORY**

An Unadjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Activity year totals for unaged data are obtained from a transaction file without vintage identification. Information displayed in the unadjusted plant history is consistent with regulated investments reported internally by the Company.

An Adjusted Plant History schedule provides a summary of recorded plant data extracted from the continuing property records maintained by the Company with sales, transfers, and adjustments appropriately aged for depreciation study purposes. Activity year total amounts shown on this schedule for aged data are obtained from a historical arrangement of the data base in which all plant accounting transactions are identified by vintage and activity year. Ageing of adjusting transactions is achieved using transaction codes that identify an adjusting year associated with the dollar amount of a transaction. Adjusting transactions processed in the adjusted plant history are not aged in the Company's records or in the unadjusted plant history.

#### **SCHEDULE D – ACTUARIAL LIFE ANALYSIS**

These schedules provide a summary of the dispersion and life indications obtained from an actuarial life analysis for a specified placement band. The observation band (Column A) is specified to produce a rolling-band, shrinking-band, or progressive-band analysis depending upon the movement of the end points of the band. The degree of censoring (or point of truncation) of the observed life table is shown in Column B for each observation band. The estimated average service life, best fitting Iowa dispersion, and a statistical measure of the goodness of fit are shown for each degree polynomial (First, Second, and Third) fitted to the estimated hazard rates. Options available in the analysis include the width and location of both the placement and observation bands; the interval of years included in a selected rolling, shrinking, or progressive band analysis; the estimator of the hazard rate (actuarial, conditional proportion retired, or maximum likelihood); the elements to include on the diagonal of a weight matrix (exposures, inverse of age, inverse of variance, or unweighted); and the age at which an observed life table is truncated.

Estimated projection lives (Columns C, F, and I) are flagged with an asterisk if negative hazard rates are indicated by the fitted polynomial. All negative hazard rates are set equal to zero in the calculation of the graduated survivor curve. The Conformance Index (Columns E, H, and K) is the square root of the mean sum-of-squared differences between the observed proportions surviving and the best fitting Iowa curve. A Conformance Index of zero would indicate a perfect fit.

#### **SCHEDULE E – GRAPHICS ANALYSIS**

This schedule provides a graphics plot of a) the observed proportion surviving for a selected placement and observation band; b) the statistically best fitting Iowa dispersion and derived average service life; and c) the projection curve and projection life selected to describe future forces of mortality.

The graphics analysis also provides a plot of the observed hazard rates and graduated hazard function for a selected placement and observation band. The estimator of the hazard rates and weighting used in fitting orthogonal polynomials to the observed data are displayed in the title block of the displayed graph.

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

**Transmission Plant  
Account: 1715 Station Equipment**

**Dispersion: 45 - S2  
Procedure: Vintage Group**

**Generation Arrangement**

Vintage	December 31, 2016		Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
	Age	Surviving Plant						
A	B	C	D	E	F	G	H=C*F*G	I=H/E
2016	0.5	499,106,480	45.00	44.50	0.9889	1.0000	493,560,838	11,091,260
2015	1.5	425,834,990	45.00	43.50	0.9667	1.0000	411,640,478	9,463,003
2014	2.5	558,023,376	45.00	42.50	0.9444	1.0000	527,024,990	12,400,520
2013	3.5	414,074,624	45.00	41.50	0.9222	1.0000	381,875,869	9,201,664
2012	4.5	376,496,169	45.00	40.50	0.9001	1.0000	338,868,916	8,366,624
2011	5.5	602,478,817	45.00	39.51	0.8779	1.0000	528,937,630	13,388,890
2010	6.5	454,959,729	44.99	38.51	0.8560	1.0000	389,441,789	10,112,240
2009	7.5	437,823,395	44.99	37.52	0.8339	1.0000	365,115,167	9,730,714
2008	8.5	196,632,784	44.99	36.54	0.8122	1.0000	159,702,418	4,370,993
2007	9.5	226,062,645	44.95	35.56	0.7912	1.0000	178,849,941	5,029,677
2006	10.5	149,023,810	44.98	34.59	0.7689	1.0000	114,591,279	3,312,940
2005	11.5	218,847,092	44.96	33.63	0.7480	1.0000	163,690,117	4,867,552
2004	12.5	182,896,670	44.99	32.68	0.7264	1.0000	132,850,465	4,065,246
2003	13.5	100,885,304	44.96	31.74	0.7060	1.0000	71,228,226	2,243,923
2002	14.5	125,397,118	45.01	30.82	0.6847	1.0000	85,855,880	2,785,697
2001	15.5	77,460,239	44.98	29.91	0.6651	1.0000	51,515,955	1,722,196
2000	16.5	144,582,246	44.99	29.02	0.6451	1.0000	93,273,678	3,213,943
1999	17.5	102,252,926	44.97	28.15	0.6260	1.0000	64,006,521	2,273,976
1998	18.5	99,735,677	45.02	27.29	0.6062	1.0000	60,458,790	2,215,295
1997	19.5	87,339,087	45.03	26.45	0.5874	1.0000	51,305,871	1,939,385
1996	20.5	95,656,155	45.01	25.64	0.5696	1.0000	54,488,447	2,125,362
1995	21.5	69,747,343	44.88	24.84	0.5535	1.0000	38,606,227	1,554,248
1994	22.5	265,648,668	45.04	24.06	0.5342	1.0000	141,916,663	5,898,172
1993	23.5	98,043,197	45.05	23.30	0.5172	1.0000	50,712,008	2,176,102
1992	24.5	368,244,015	45.25	22.57	0.4988	1.0000	183,671,405	8,138,866
1991	25.5	263,392,543	45.11	21.85	0.4843	1.0000	127,573,502	5,838,455
1990	26.5	383,680,609	45.40	21.15	0.4659	1.0000	178,754,281	8,450,246
1989	27.5	127,196,506	45.50	20.48	0.4500	1.0000	57,239,996	2,795,332
1988	28.5	103,855,712	45.54	19.82	0.4352	1.0000	45,200,449	2,280,493
1987	29.5	152,205,839	45.79	19.18	0.4189	1.0000	63,762,212	3,323,899
1986	30.5	47,083,345	45.77	18.56	0.4056	1.0000	19,095,957	1,028,644
1985	31.5	48,885,284	46.17	17.96	0.3890	1.0000	19,018,079	1,058,697
1984	32.5	46,304,694	46.37	17.38	0.3748	1.0000	17,355,813	998,501
1983	33.5	77,920,839	46.46	16.82	0.3619	1.0000	28,203,228	1,677,027
1982	34.5	48,992,701	46.58	16.27	0.3493	1.0000	17,111,292	1,051,733
1981	35.5	48,789,821	46.51	15.74	0.3384	1.0000	16,508,691	1,048,952
1980	36.5	155,536,252	47.14	15.22	0.3229	1.0000	50,225,821	3,299,342

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

**Transmission Plant  
Account: 1715 Station Equipment**

**Dispersion: 45 - S2  
Procedure: Vintage Group**

**Generation Arrangement**

Vintage	December 31, 2016		Avg. Life	Rem. Life	Net Plant Ratio	Alloc. Factor	Computed Net Plant	Accrual
	Age	Surviving Plant						
A	B	C	D	E	F	G	H=C*F*G	I=H/E
1979	37.5	129,595,008	47.53	14.72	0.3098	1.0000	40,144,242	2,726,608
1978	38.5	53,602,362	47.27	14.24	0.3012	1.0000	16,145,447	1,133,967
1977	39.5	54,041,642	47.77	13.77	0.2882	1.0000	15,574,640	1,131,285
1976	40.5	43,222,781	48.11	13.31	0.2766	1.0000	11,957,040	898,352
1975	41.5	41,364,214	48.53	12.87	0.2651	1.0000	10,965,298	852,260
1974	42.5	41,621,186	48.72	12.44	0.2553	1.0000	10,624,243	854,379
1973	43.5	28,900,495	49.07	12.02	0.2449	1.0000	7,077,610	589,012
1972	44.5	32,634,851	49.88	11.61	0.2327	1.0000	7,595,222	654,270
1971	45.5	42,955,902	50.17	11.21	0.2235	1.0000	9,600,196	856,194
1970	46.5	50,932,184	50.91	10.83	0.2127	1.0000	10,831,676	1,000,409
1969	47.5	33,284,919	51.37	10.45	0.2035	1.0000	6,772,998	647,994
1968	48.5	17,439,504	51.76	10.09	0.1949	1.0000	3,398,521	336,913
1967	49.5	9,489,512	51.79	9.73	0.1879	1.0000	1,782,992	183,216
1966	50.5	12,128,522	52.77	9.38	0.1778	1.0000	2,156,832	229,819
1965	51.5	34,753,799	53.45	9.05	0.1693	1.0000	5,882,544	650,217
1963	53.5	223,846	55.89	8.40	0.1502	1.0000	33,627	4,005
1962	54.5	839,768	56.62	8.08	0.1428	1.0000	119,877	14,833
1960	56.5	45,831,025	56.96	7.48	0.1312	1.0000	6,014,364	804,569
1958	58.5	812	59.74	6.90	0.1154	1.0000	94	14
1956	60.5	52,288	61.41	6.34	0.1032	1.0000	5,399	851
1955	61.5	46,606,501	60.86	6.07	0.0998	1.0000	4,649,815	765,754
1953	63.5	33,140	64.05	5.55	0.0867	1.0000	2,872	517
1950	66.5	35,400,698	65.34	4.81	0.0735	1.0000	2,603,476	541,768
Total	15.8	\$8,636,051,657	45.59	31.40	0.6886	1.0000	\$5,947,177,915	\$189,417,010

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

**Transmission Plant**

**Account: 1715 Station Equipment**

**Age Distribution**

Vintage	Age as of 12/31/2016	Derived Additions	2000 Opening Balance	Experience to 12/31/2016		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
2016	0.5	499,106,480		499,106,480	1.0000	0.5000
2015	1.5	425,834,990		425,834,990	1.0000	1.5000
2014	2.5	558,023,376		558,023,376	1.0000	2.5000
2013	3.5	414,079,146		414,074,624	1.0000	3.5000
2012	4.5	376,530,617		376,496,169	0.9999	4.4997
2011	5.5	603,239,448		602,478,817	0.9987	5.4983
2010	6.5	455,889,852		454,959,729	0.9980	6.4906
2009	7.5	438,554,990		437,823,395	0.9983	7.4932
2008	8.5	197,289,117		196,632,784	0.9967	8.4843
2007	9.5	229,191,831		226,062,645	0.9863	9.4429
2006	10.5	150,018,999		149,023,810	0.9934	10.4775
2005	11.5	224,517,398		218,847,092	0.9747	11.4526
2004	12.5	183,878,264		182,896,670	0.9947	12.4781
2003	13.5	102,463,285		100,885,304	0.9846	13.4410
2002	14.5	125,830,732		125,397,118	0.9966	14.4880
2001	15.5	78,218,149		77,460,239	0.9903	15.4400
2000	16.5	146,422,931		144,582,246	0.9874	16.4339
1999	17.5		103,749,694	102,252,926	0.9856	17.3962
1998	18.5		100,852,187	99,735,677	0.9889	18.4280
1997	19.5		88,460,809	87,339,087	0.9873	19.4125
1996	20.5		97,744,204	95,656,155	0.9786	20.3502
1995	21.5		72,350,937	69,747,343	0.9640	21.1764
1994	22.5		273,953,593	265,648,668	0.9697	22.2901
1993	23.5		100,946,380	98,043,197	0.9712	23.2461
1992	24.5		376,393,083	368,244,015	0.9783	24.3672
1991	25.5		272,960,157	263,392,543	0.9649	25.1547
1990	26.5		391,795,023	383,680,609	0.9793	26.3530
1989	27.5		129,608,724	127,196,506	0.9814	27.3452
1988	28.5		106,805,578	103,855,712	0.9724	28.2622
1987	29.5		154,263,846	152,205,839	0.9867	29.3764
1986	30.5		49,042,874	47,083,345	0.9600	30.2044
1985	31.5		49,307,586	48,885,284	0.9914	31.4367
1984	32.5		46,520,300	46,304,694	0.9954	32.4468
1983	33.5		81,400,172	77,920,839	0.9573	33.3274
1982	34.5		51,205,055	48,992,701	0.9568	34.2172
1981	35.5		54,595,330	48,789,821	0.8937	34.8963
1980	36.5		161,477,840	155,536,252	0.9632	36.2517
1979	37.5		133,753,032	129,595,008	0.9689	37.3435

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

**Transmission Plant**

**Account: 1715 Station Equipment**

**Age Distribution**

Vintage	Age as of 12/31/2016	Derived Additions	2000 Opening Balance	Experience to 12/31/2016		
				Amount Surviving	Proportion Surviving	Realized Life
A	B	C	D	E	F=E/(C+D)	G
1978	38.5		58,653,499	53,602,362	0.9139	37.7633
1977	39.5		60,153,445	54,041,642	0.8984	38.9190
1976	40.5		47,027,483	43,222,781	0.9191	39.8925
1975	41.5		45,401,199	41,364,214	0.9111	40.9187
1974	42.5		48,683,278	41,621,186	0.8549	41.6780
1973	43.5		33,251,887	28,900,495	0.8691	42.5817
1972	44.5		35,350,563	32,634,851	0.9232	43.9218
1971	45.5		48,337,891	42,955,902	0.8887	44.7128
1970	46.5		55,558,598	50,932,184	0.9167	45.9269
1969	47.5		36,512,835	33,284,919	0.9116	46.8289
1968	48.5		19,900,875	17,439,504	0.8763	47.6465
1967	49.5		11,147,246	9,489,512	0.8513	48.0734
1966	50.5		14,068,248	12,128,522	0.8621	49.4231
1965	51.5		40,451,405	34,753,799	0.8591	50.4431
1963	53.5		223,846	223,846	1.0000	53.5000
1962	54.5		839,768	839,768	1.0000	54.5000
1960	56.5		53,511,316	45,831,025	0.8565	55.3272
1958	58.5		812	812	1.0000	58.5000
1956	60.5		52,288	52,288	1.0000	60.5000
1955	61.5		55,756,212	46,606,501	0.8359	60.0848
1953	63.5		33,140	33,140	1.0000	63.5000
1950	66.5		42,762,492	35,400,698	0.8278	65.0345
Total	15.8	\$5,209,089,604	\$3,604,864,732	\$8,636,051,657	0.9798	

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

Transmission Plant

Account: 1715 Station Equipment

Schedule C

Page 1 of 1

**Unadjusted Plant History**

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	3,614,235,886	118,191,442	2,555,440	22,361,942	3,752,233,829
2001	3,752,233,829	73,238,191	3,982,516	22,536,997	3,844,026,500
2002	3,844,026,500	65,399,789	7,443,045	5,958,147	3,907,941,391
2003	3,907,941,391	106,559,019	2,517,339	(1,040,636)	4,010,942,435
2004	4,010,942,435	118,022,342	14,404,097	51,979,207	4,166,539,886
2005	4,166,539,886	82,292,407	8,645,819	143,492,615	4,383,679,090
2006	4,383,679,090	119,427,072	5,174,411	8,491,077	4,506,422,828
2007	4,506,422,828	230,356,875	17,682,749	42,446,113	4,761,543,066
2008	4,761,543,066	31,412,693	7,078,185	127,829,983	4,913,707,557
2009	4,913,707,557	357,324,800	7,864,743	40,182,801	5,303,350,416
2010	5,303,350,416	557,449,189	8,126,169	(103,974)	5,852,569,462
2011	5,852,569,462	595,247,424	12,298,745	(183,684)	6,435,334,457
2012	6,435,334,457	359,985,856	26,800,834	(97,959)	6,768,421,520
2013	6,768,421,520	434,126,756	18,757,215	(5,189)	7,183,785,872
2014	7,183,785,872	583,466,298	16,408,611	(10,174)	7,750,833,384

PAGE 28

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

Transmission Plant

Account: 1715 Station Equipment

Schedule C

Page 1 of 1

**Adjusted Plant History**

Year	Beginning Balance	Additions	Retirements	Sales, Transfers & Adjustments	Ending Balance
A	B	C	D	E	F=B+C-D+E
2000	3,634,283,488	145,278,841	2,555,440		3,777,006,889
2001	3,777,006,889	76,479,157	3,982,516	(156,246)	3,849,347,284
2002	3,849,347,284	123,475,163	7,443,045	(9,139,843)	3,956,239,558
2003	3,956,239,558	107,667,522	2,503,831	298,348	4,061,701,597
2004	4,061,701,597	183,526,382	14,023,935	(484,553)	4,230,719,491
2005	4,230,719,491	220,882,770	8,645,819	52,925	4,443,009,368
2006	4,443,009,368	149,396,161	5,174,411	(14,173,201)	4,573,057,917
2007	4,573,057,917	229,792,815	17,682,749	6,578,822	4,791,746,804
2008	4,791,746,804	204,188,305	7,078,185	(418,411)	4,988,438,513
2009	4,988,438,513	443,860,324	7,864,743	1,411,494	5,425,845,588
2010	5,425,845,588	491,288,650	8,126,169	(103,974)	5,908,904,095
2011	5,908,904,095	594,966,146	12,298,745	(41,594)	6,491,529,903
2012	6,491,529,903	371,726,573	26,800,834	(20,792)	6,836,434,849
2013	6,836,434,849	415,308,768	18,757,215	(5,189)	7,232,981,213
2014	7,232,981,213	534,260,782	16,408,611		7,750,833,384

PAGE 29

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

Transmission Plant

Account: 1715 Station Equipment

Schedule D

Page 1 of 1

T-Cut: None

Placement Band: 1950-2016

Hazard Function: Proportion Retired

**Rolling Band Life Analysis**

Weighting: Exposures

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index	Average Life	Disper-sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2004	78.4	99.2	L1.5*	1.16	75.7	S1.5	0.46	71.7	S2	0.48
2001-2005	74.2	92.9	L1.5*	1.43	72.4	S1.5	0.50	69.2	S2	0.55
2002-2006	74.6	95.5	L1.5*	1.52	74.3	S1.5	0.61	70.6	S2	0.58
2003-2007	73.9	94.9	L1.5*	1.10	77.2	S1.5	0.51	72.7	R2.5	0.51
2004-2008	74.6	98.1	L1*	0.98	82.5	S1	0.54	74.8	R2.5	0.55
2005-2009	78.5	106.8	L1*	0.73	92.7	S1	0.48	81.7	R2.5*	0.44
2006-2010	80.0	112.4	L1*	0.79	104.5	S0.5	0.68	105.2	L1.5	0.68
2007-2011	77.0	107.5	L1*	0.98	93.7	S0.5	0.70	133.7	SC*	0.63
2008-2012	72.3	97.2	L1.5*	1.56	83.0	S1	1.21	150.2	SC*	0.73
2009-2013	65.8	90.7	L1.5*	1.86	75.2	S1.5	1.37	123.6	SC*	1.01
2010-2014	62.6	88.0	L1.5*	1.93	73.1	S1.5	1.23	110.6	O3*	0.93
2011-2015	61.7	89.3	L1.5*	2.16	74.2	S1.5	1.25	98.6	L0*	1.09
2012-2016	66.1	96.0	L1.5*	1.87	79.6	S1	1.14	116.7	L0*	1.00

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

Transmission Plant

Account: 1715 Station Equipment

Schedule D

Page 1 of 1

T-Cut: None

Placement Band: 1950-2016

Hazard Function: Proportion Retired

Weighting: Exposures

**Shrinking Band Life Analysis**

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2016	68.2	100.4	L1.5*	1.84	81.9	S1.5	0.76	102.3	L0.5*	0.69
2002-2016	67.8	99.2	L1.5*	1.81	81.4	S1	0.79	103.7	L0*	0.70
2004-2016	67.7	99.4	L1.5*	1.82	82.1	S1	0.88	100.5	L0.5*	0.82
2006-2016	68.9	101.4	L1.5*	1.62	84.0	S1	0.82	109.1	L0*	0.76
2008-2016	68.5	101.6	L1.5*	1.96	83.3	S1	1.04	119.8	SC*	0.95
2010-2016	66.2	98.4	L1.5*	2.25	80.7	S1.5	1.25	126.6	SC*	1.13
2012-2016	66.1	96.0	L1.5*	1.87	79.6	S1	1.14	116.7	L0*	1.00
2014-2016	79.9	115.8	S0*	0.64	92.9	S1.5	1.00	95.6	S1	0.99
2016-2016	94.5	160.6	R2*	0.62	143.8	R2*	0.73	187.9	R4*	0.60

**HYDRO ONE NETWORKS INC. - TRANSMISSION**

**Transmission Plant**

**Account: 1715 Station Equipment**

T-Cut: None

Placement Band: 1950-2016

Hazard Function: Proportion Retired

Weighting: Exposures

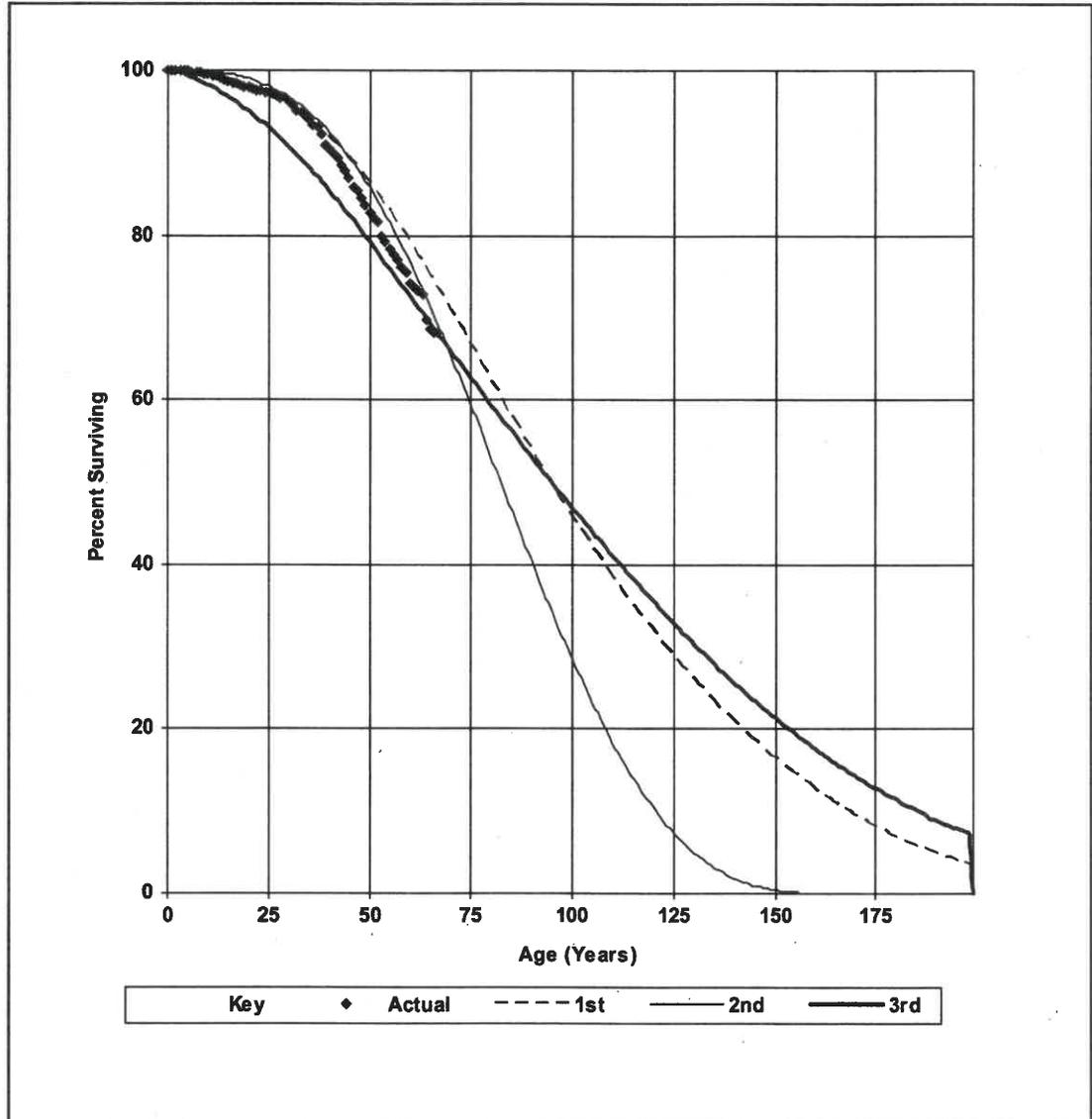
**Progressing Band Life Analysis**

Observation Band	Censoring	First Degree			Second Degree			Third Degree		
		Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index	Average Life	Disper- sion	Conf. Index
A	B	C	D	E	F	G	H	I	J	K
2000-2001	92.9	131.0	S0 *	0.70	101.4	S1.5	0.85	171.1	R1.5 *	0.96
2000-2003	84.9	108.5	L1.5 *	0.67	80.1	S2	0.65	78.5	S2	0.62
2000-2005	75.7	96.5	L1.5 *	1.35	74.0	S1.5	0.45	70.1	S2	0.48
2000-2007	74.4	97.4	L1.5 *	1.29	77.8	S1.5	0.51	74.0	S2	0.55
2000-2009	76.6	103.5	L1.5 *	1.15	84.3	S1	0.51	79.6	S1.5	0.51
2000-2011	75.6	104.5	L1.5 *	1.30	84.7	S1	0.63	92.9	L1.5 *	0.59
2000-2013	68.4	95.4	L1.5 *	1.49	77.7	S1.5	0.88	90.7	L1.5 *	0.74
2000-2015	66.5	96.6	L1.5 *	1.79	78.7	S1.5	0.72	84.4	L2 *	0.64
2000-2016	68.2	100.4	L1.5 *	1.84	81.9	S1.5	0.76	102.3	L0.5 *	0.69

**HYDRO ONE NETWORKS INC. - TRANSMISSION**  
Transmission Plant  
Account: 1715 Station Equipment

T-Cut: None  
Placement Band: 1950-2016 Observation Band: 2000-2016  
Hazard Function: Proportion Retired  
Weighting: Exposures  
1st: 100.4-L1.5 2nd: 81.9-S1.5 3rd: 102.3-L0.5

**Survivorship Functions**

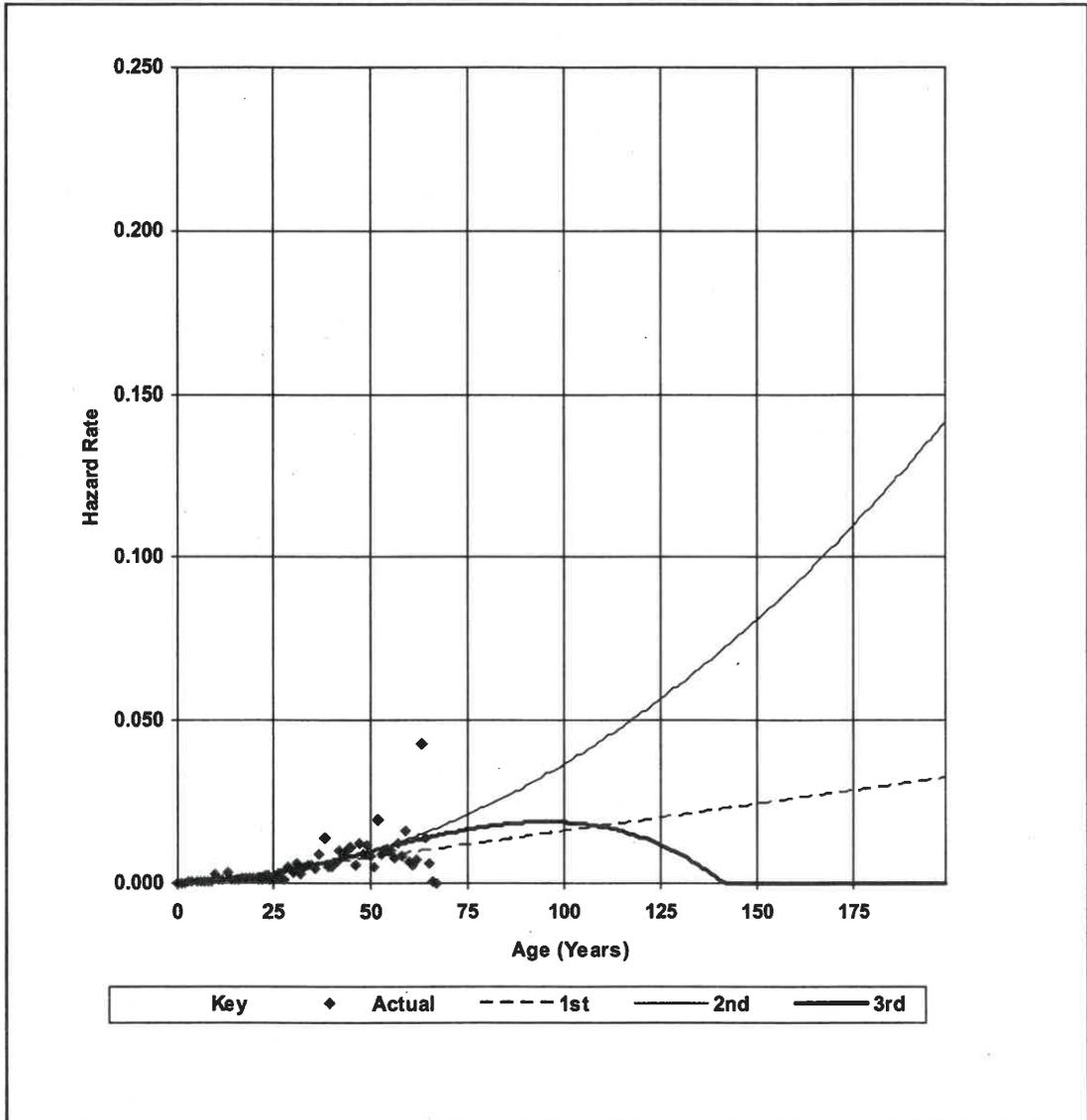


**HYDRO ONE NETWORKS INC. - TRANSMISSION**  
Transmission Plant  
Account: 1715 Station Equipment

T-Cut: None  
Placement Band: 1950-2016 Observation Band: 2000-2016  
Hazard Function: Proportion Retired  
Weighting: Exposures

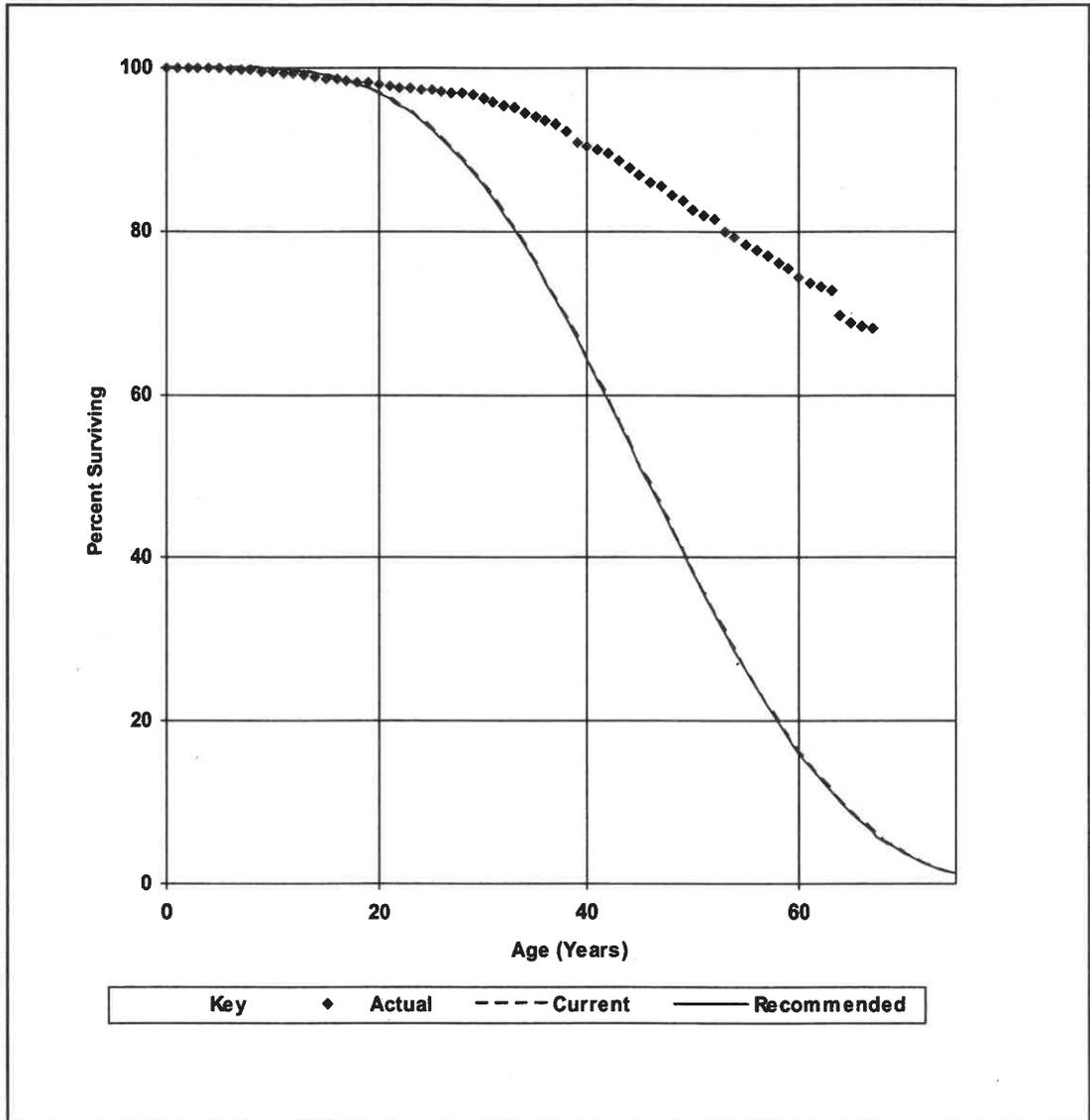
**Polynomial Hazard Functions**

1st: 100.4-L1.5 2nd: 81.9-S1.5 3rd: 102.3-L0.5



T-Cut: None  
 Placement Band: 1950-2016  
 Observation Band: 2000-2016

**Current and Recommended Projection Life Curves**      Current: 45.0-S2    Recommended: 45.0-S2



*Expert Rule 13A*

# EXPERT RULE 13A

## TITLE OF REPORT

2017 Depreciation Rate Review  
—Transmission Operations

## CONSULTANT

Ronald E. White, Ph.D.  
Foster Associates Consultants, LLC  
17595 S. Tamiami Trail, Suite 260  
Fort Myers, FL 33908

## QUALIFICATIONS

See attached Professional Qualifications.

## INSTRUCTIONS PROVIDED

Foster Associates was instructed to conduct a 2017 Depreciation Rate Review and provide recommended depreciation rates for USoA categories derived from service life statistics estimated for category classifications adopted by Hydro One Networks for engineering operations and planning purposes.

## BASIS OF EVIDENCE

Specific information and factual assumptions upon which the 2017 Depreciation Rate Review is based are contained within the titled report.

## CONFIRMATION

Dr. White has been made aware of and agrees to accept the responsibilities that are or may be imposed as set forth in Rule 13A.



Ronald E. White, Ph.D.

August 8, 2017

**FORM A**

Proceeding: \_\_\_\_\_

**ACKNOWLEDGMENT OF EXPERT'S DUTY**

1. My name is Ronald E. White, Ph.D. (*name*). I live at Fort Myers (*city*), in the state of Florida (*province/state*) in the United States.
2. I have been engaged by or on behalf of Hydro One Networks (*name of party/parties*) to provide evidence in relation to the above-noted proceeding before the Ontario Energy Board.
3. I acknowledge that it is my duty to provide evidence in relation to this proceeding as follows:
  - (a) to provide opinion evidence that is fair, objective and non-partisan;
  - (b) to provide opinion evidence that is related only to matters that are within my area of expertise; and
  - (c) to provide such additional assistance as the Board may reasonably require, to determine a matter in issue.
4. I acknowledge that the duty referred to above prevails over any obligation which I may owe to any party by whom or on whose behalf I am engaged.

Date 08/08/2017



\_\_\_\_\_  
*Signature*

## **PROFESSIONAL QUALIFICATIONS**

### **NAME AND ADDRESS**

Ronald E. White, Ph.D.  
Foster Associates Consultants, LLC  
17595 S. Tamiami Trail, Suite 260  
Fort Myers, FL 33908

### **EDUCATION**

1961 - 1964 Valparaiso University

Major: Electrical Engineering

1965 Iowa State University

B.S., Engineering Operations

1968 Iowa State University

M.S., Engineering Valuation

Thesis: The Multivariate Normal Distribution and the Simulated Plant Record  
Method of Life Analysis

1977 Iowa State University

Ph.D., Engineering Valuation

Minor: Economics

Dissertation: A Comparative Analysis of Various Estimates of the Hazard Rate  
Associated With the Service Life of Industrial Property

### **EMPLOYMENT**

2015 - Foster Associates Consultants, LLC  
President

2007 - 2015 Foster Associates, Inc.  
Chairman

1996 - 2007 Foster Associates, Inc.  
Executive Vice President

1988 - 1996 Foster Associates, Inc.  
Senior Vice President

1979 - 1988 Foster Associates, Inc.  
Vice President

1978 - 1979 Northern States Power Company  
Assistant Treasurer

1974 - 1978 Northern States Power Company  
 Manager, Corporate Economics

1972 - 1974 Northern States Power Company  
 Corporate Economist

1970 - 1972 Iowa State University  
 Graduate Student and Instructor

1968 - 1970 Northern States Power Company  
 Valuation Engineer

1965 - 1968 Iowa State University  
 Graduate Student and Teaching Assistant

### **PUBLICATIONS**

*A New Set of Generalized Survivor Tables*, Journal of the Society of Depreciation Professionals, October, 1992.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, Journal of the Society of Depreciation Professionals, December, 1989.

*Standards for Depreciation Accounting Under Regulated Competition*, paper presented at The Institute for Study of Regulation, Rate Symposium, February, 1985.

*The Economics of Price-Level Depreciation*, paper presented at the Iowa State University Regulatory Conference, May, 1981.

*Depreciation and the Discount Rate for Capital Investment Decisions*, paper presented at the National Communications Forum - National Electronics Conference, October 1979.

*A Computerized Method for Generating a Life Table From the 'h-System' of Survival Functions*, paper presented at the American Gas Association - Edison Electric Institute Depreciation Accounting Committee Meeting, December, 1975.

*The Problem With AFDC is ...*, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1973.

*The Simulated Plant-Record Method of Life Analysis*, paper presented at the Missouri Public Service Commission Regulatory Information Systems Conference, May, 1971.

*Simulated Plant-Record Survivor Analysis Program (User's Manual)*, special report published by Engineering Research Institute, Iowa State University, February, 1971.

A Test Procedure for the Simulated Plant-Record Method of Life Analysis, Journal of the American Statistical Association, September, 1970.

*Modeling the Behavior of Property Records*, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, May, 1970.

*A Technique for Simulating the Retirement Experience of Limited-Life Industrial Property*, paper presented at the National Conference of Electric and Gas Utility Accountants, May, 1969.

*How Dependable are Simulated Plant-Record Estimates?*, paper presented at the Iowa State University Conference on Public Utility Valuation and the Rate Making Process, April, 1968.

### **TESTIFYING WITNESS**

Alabama Public Service Commission, Docket No. 18488, General Telephone Company of the Southeast; testimony concerning engineering economy study techniques.

Alabama Public Service Commission, Docket No. 20208, General Telephone Company of the South; testimony concerning the equal-life group procedure and remaining-life technique.

Alberta Energy and Utilities Board, Application No. 1250392, Aquila Networks Canada; rebuttal testimony supporting proposed depreciation rates.

Alberta Energy and Utilities Board, Case No. RE95081, Edmonton Power Inc.; rebuttal evidence concerning appropriate depreciation rates.

Alberta Energy and Utilities Board, 1999/2000 General Tariff Application, Edmonton Power Inc.; direct and rebuttal evidence concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. T-01051B-97-0689, U S West Communications, Inc.; testimony concerning appropriate depreciation rates.

Arizona Corporation Commission, Docket No. G-1032A-02-0598, Citizens Communications Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-01345A-08-0172, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-0135A-03-0437, Arizona Public Service Company; rebuttal testimony supporting net salvage rates.

Arizona Corporation Commission, Docket No. E-01345A-05-0816, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-01345A-11-0224, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-01345A-16-0036, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-01933A-12-0126, Tucson Electric Power Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-01933A-15-0322, Tucson Electric Power Company; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. G-04204A-06-0463, UNS Gas, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-04204A-06-0783, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-04204A-09-0206, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona Corporation Commission, Docket No. E-04204A-15-0142, UNS Electric, Inc.; testimony supporting proposed depreciation rates.

Arizona State Board of Equalization, Docket No. 6302-07-2, Arizona Public Service Company; testimony concerning valuation and assessment of contributions in aid of construction.

California Public Utilities Commission, Case Nos. A.92-06-040, 92-06-042, GTE California Incorporated; rebuttal testimony supporting depreciation study techniques.

California Public Utilities Commission. Docket No. GRC A.05-12-002, Pacific Gas and Electric Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Docket No. GRC A.06-12-009/A.06-12-010, San Diego Gas & Electric Company and Southern California Gas Company; testimony regarding estimation of net salvage rates.

California Public Utilities Commission. Application No. A.16-09-001, Southern California Edison; testimony regarding estimation of service lives and net salvage rates.

Public Utilities Commission of the State of Colorado, Application No. 36883-Reopened. U S WEST Communications; testimony concerning equal-life group procedure.

State of Connecticut Department of Public Utility Control, Docket No. 10-12-02, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 09-12-05, The Connecticut Light and Power Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 06-12PH01, Yankee Gas Services Company; testimony supporting recommended depreciation rates.

State of Connecticut Department of Public Utility Control, Docket No. 05-03-17, The Southern Connecticut Gas Company; testimony supporting recommended depreciation rates.

Delaware Public Service Commission, Docket No. 81-8, Diamond State Telephone Company; testimony concerning the amortization of inside wiring.

Delaware Public Service Commission, Docket No. 82-32, Diamond State Telephone Company; testimony concerning the equal-life group procedure and remaining-life technique.

Public Service Commission of the District of Columbia, Formal Case No. 842, District of Columbia Natural Gas; testimony concerning depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1016, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1054, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1093, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1115, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Public Service Commission of the District of Columbia, Formal Case No. 1137, Washington Gas Light Company - District of Columbia; testimony supporting proposed depreciation rates.

Federal Communications Commission, Prescription of Revised Depreciation Rates for AT&T Communications; statement concerning depreciation, regulation and competition.

Federal Communications Commission, Petition for Modification of FCC Depreciation Prescription Practices for AT&T; statement concerning alignment of depreciation expense used for financial reporting and regulatory purposes.

Federal Communications Commission, Docket No. 99-117, Bell Atlantic; affidavit concerning revenue requirement and capital recovery implications of omitted plant retirements.

Federal Energy Regulatory Commission, Docket No. RP14-118-000, WBI Energy Transmission, Inc.; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-2110-000, ITC Midwest; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER10-185-000, Michigan Electric Transmission Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER09-1530-000, ITC *Transmission*; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER95-267-000, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER11-3638-000, Arizona Public Service Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. RP89-248, Mississippi River Transmission Corporation; rebuttal testimony concerning appropriateness of net salvage component in depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER91-565, New England Power Company; testimony supporting proposed depreciation rates.

Federal Energy Regulatory Commission, Docket No. ER78-291, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Energy Regulatory Commission, Docket Nos. RP80-97 and RP81-54, Tennessee Gas Pipeline Company; testimony concerning offshore plant depreciation rates.

Federal Power Commission, Docket No. E-8252, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. E-9148, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Federal Power Commission, Docket No. ER76-818, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Federal Power Commission, Docket No. RP74-80, *Northern* Natural Gas Company; testimony concerning depreciation expense.

Public Utilities Commission of the State of Hawaii, Docket No. 00-0309, The Gas Company; testimony supporting proposed depreciation rates.

Public Utilities Commission of the State of Hawaii, Docket No. 94-0298, GTE Hawaiian Telephone Company Incorporated; testimony concerning the need for shortened service lives and disclosure of asset impairment losses.

Idaho Public Utilities Commission, Case No. U-1002-59, General Telephone Company of the Northwest, Inc.; testimony concerning the remaining-life technique and the equal-life group procedure.

Illinois Commerce Commission, Case No. 04-0476, Illinois Power Company; testimony supporting proposed depreciation rates.

Illinois Commerce Commission, Docket No. 94-0481, Citizens Utilities Company of Illinois; rebuttal testimony concerning applications of the Simulated Plant-Record method of life analysis.

Iowa State Commerce Commission, Docket No. RPU 82-47, North Central Public Service Company; testimony on depreciation rates.

Iowa State Commerce Commission, Docket No. RPU 84-34, General Telephone Company of the Midwest; testimony concerning the remaining-life technique and the equal-life group procedure.

Iowa State Utilities Board, Docket No. DPU-86-2, Northwestern Bell Telephone Company; testimony concerning capital recovery in competition.

Iowa State Utilities Board, Docket No. RPU-84-7, Northwestern Bell Telephone Company; testimony concerning the deduction of a reserve deficiency from the rate base.

Iowa State Utilities Board, Docket No. DPU-88-6, U S WEST Communications; testimony concerning depreciation subject to refund.

Iowa State Utilities Board, Docket No. RPU-90-9, Central Telephone Company of Iowa; testimony concerning depreciation rates.

Iowa State Utilities Board, Docket No. RPU-93-9, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. DPU-96-1, U S WEST Communications; testimony concerning principles of depreciation accounting and abandonment of FASB 71.

Iowa State Utilities Board, Docket No. RPU-05-2, Aquila Networks; testimony supporting recommended depreciation rates.

Kansas Corporation Commission, Docket No. 16-KGSG-491-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-KGSG-835-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 12-WSEE-112-RTS, Westar Energy, Inc.; testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 10-KCPE-415-RTS; Kansas City Power and Light; cross-answering testimony addressing the recording and treatment of third-party reimbursements in estimating net salvage rates.

Kansas Corporation Commission, Docket No. 04-AQLE-1065-RTS, Aquila Networks – WPE (Kansas); testimony supporting proposed depreciation rates.

Kansas Corporation Commission, Docket No. 03-KGSG-602-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; rebuttal testimony supporting net salvage rates.

Kansas Corporation Commission, Docket No. 06-KGSG-1209-RTS, Kansas Gas Service, a Division of ONEOK, Inc.; testimony supporting proposed depreciation rates.

Kentucky Public Service Commission, Case No. 97-224, Jackson Purchase Electric Cooperative Corporation; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9096, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8485, Baltimore Gas and Electric Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9424, Delmarva Power and Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9385, Potomac Electric Power Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 9103, Washington Gas Light Company; rebuttal testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 8960, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Maryland Public Service Commission, Case No. 7689, Washington Gas Light Company; testimony concerning life analysis and net salvage.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 15-155, Massachusetts Electric Company/Nantucket Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Public Utilities, D.P.U. 10-70, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Commonwealth of Massachusetts Department of Telecommunications and Energy, D.T.E. 06-55, Western Massachusetts Electric Company; testimony supporting proposed depreciation rates.

Massachusetts Department of Public Utilities, Case No. DPU 91-52, Massachusetts Electric Company; testimony supporting proposed depreciation rates which include a net salvage component.

Michigan Public Service Commission, Case No. U-18150, DTE Electric Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-16991, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-16117, The Detroit Edison Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-15699, Michigan Consolidated Gas Company; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-13899, Michigan Consolidated Gas Company; testimony concerning service life estimates.

Michigan Public Service Commission, Case No. U-13393, Aquila Networks – MGU; testimony supporting proposed depreciation rates.

Michigan Public Service Commission, Case No. U-12395, Michigan Gas Utilities; testimony supporting proposed depreciation rates including amortization accounting and redistribution of recorded reserves.

Michigan Public Service Commission, Case No. U-6587, General Telephone Company of Michigan; testimony concerning use of a theoretical depreciation reserve with the remaining-life technique.

Michigan Public Service Commission, Case No. U-7134, General Telephone Company of Michigan; testimony concerning the equal-life group depreciation procedure.

Minnesota Public Service Commission, Docket No. E-611, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Minnesota Public Service Commission, Docket No. E-1086, Northern States Power Company; testimony concerning depreciation rates.

Minnesota Public Service Commission, Docket No. G-1015, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Public Service Commission of the State of Missouri, Case No. ER-2009-0090, KCP&L Greater Missouri Operations, rebuttal testimony concerning depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2001-672, Missouri Public Service, a division of Utilicorp United Inc.; surrebuttal testimony regarding computation of income tax expense.

Public Service Commission of the State of Missouri, Case No. TO-82-3, Southwestern Bell Telephone Company; rebuttal testimony concerning the remaining-life technique and the equal-life group procedure.

Public Service Commission of the State of Missouri, Case No. GO-97-79, Laclede Gas Company; rebuttal testimony concerning adequacy of database for conducting depreciation studies.

Public Service Commission of the State of Missouri, Case No. GR-99-315, Laclede Gas Company; rebuttal testimony concerning treatment of net salvage in development of depreciation rates.

Public Service Commission of the State of Missouri, Case No. HR-2004-0024, Aquila Inc. d/b/a/ Aquila Networks-L & P; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. ER-2004-0034, Aquila Inc. d/b/a/ Aquila Networks-L & P and Aquila Networks-MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Missouri, Case No. GR-2004-0072, Aquila Inc. d/b/a/ Aquila Networks-L & P and Aquila Networks-MPS; testimony supporting depreciation rates.

Public Service Commission of the State of Montana, Docket No. 88.2.5, Mountain State Telephone and Telegraph Company; rebuttal testimony concerning the equal-life group procedure and amortization of reserve imbalances.

Montana Public Service Commission, Docket No. D95.9.128, The Montana Power Company; testimony supporting proposed depreciation rates.

Nebraska Public Service Commission, Docket No. NG-0041, Aquila Networks (PNG Nebraska); testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 92-7002, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

Public Service Commission of Nevada, Docket No. 91-5054, Central Telephone Company-Nevada; testimony supporting proposed depreciation rates.

New Hampshire Public Utilities Commission, Docket No. DR95-169, Granite State Electric Company; testimony supporting proposed net salvage rates.

New Jersey Board of Public Utilities, Docket No. GR07110889, New Jersey Natural Gas Company; testimony supporting proposed depreciation rates.

New Jersey Board of Public Utilities, Docket No. GR 87060552, New Jersey Natural Gas Company; testimony supporting depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR93040114J, New Jersey Natural Gas Company; testimony supporting depreciation rates.

New Jersey Board of Regulatory Commissioners, Docket No. GR15111304, New Jersey Natural Gas Company; testimony supporting depreciation rates.

New York Public Service Commission, Case No. 12-G-0202. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

New York Public Service Commission, Case No. 10-E-0050. Niagara Mohawk Power Corporation d/b/a National Grid; testimony supporting recommended depreciation rates.

North Carolina Utilities Commission, Docket No. E-7, SUB 487, Duke Power Company; rebuttal testimony concerning proposed depreciation rates.

North Carolina Utilities Commission, Docket No. P-19, SUB 207, General Telephone Company of the South; rebuttal testimony concerning the equal-life group depreciation procedure.

North Dakota Public Service Commission, Case No. 8860, Northern States Power Company; testimony concerning general financial requirements.

North Dakota Public Service Commission, Case No. 9634, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9666, Northern States Power Company; testimony concerning rate of return and general financial requirements.

North Dakota Public Service Commission, Case No. 9741, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Oklahoma Corporation Commission, Cause No. PUD 201500213, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Oklahoma Corporation Commission, Cause No. PUD 200900110, Oklahoma Natural Gas Company; testimony supporting revised depreciation rates.

Ontario Energy Board, E.B.R.O. 385, Tecumseh Gas Storage Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 388, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 456, Union Gas Limited; testimony concerning depreciation rates.

Ontario Energy Board, E.B.R.O. 476-03, Union Gas Limited; testimony concerning depreciation rates.

Public Utilities Commission of Ohio, Case No. 81-383-TP-AIR, General Telephone Company of Ohio; testimony in support of the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 82-886-TP-AIR, General Telephone Company of Ohio; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 84-1026-TP-AIR, General Telephone Company of Ohio; testimony in support of the equal-life group procedure and the remaining-life technique.

Public Utilities Commission of Ohio, Case No. 81-1433, The Ohio Bell Telephone Company; testimony concerning the remaining-life technique and the equal-life group procedure.

Public Utilities Commission of Ohio, Case No. 83-300-TP-AIR, The Ohio Bell Telephone Company; testimony concerning straight-line age-life depreciation.

Public Utilities Commission of Ohio, Case No. 84-1435-TP-AIR, The Ohio Bell Telephone Company; testimony in support of test period depreciation expense.

Public Utilities Commission of Oregon, Docket No. UM 204, GTE of the Northwest; testimony concerning the theory and practice of depreciation accounting under public utility regulation.

Public Utilities Commission of Oregon, Docket No. UM 840, GTE Northwest Incorporated; rebuttal testimony concerning principles of capital recovery.

Pennsylvania Public Utility Commission, Docket No. R-80061235, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811512, General Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-811819, The Bell Telephone Company of Pennsylvania; testimony concerning the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. R-822109, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique.

Pennsylvania Public Utility Commission, Docket No. R-850229, General Telephone Company of Pennsylvania; testimony in support of the remaining-life technique and the proper depreciation reserve to be used with an original cost rate base.

Pennsylvania Public Utility Commission, Docket No. C-860923, The Bell Telephone Company of Pennsylvania; testimony concerning capital recovery under competition.

Rhode Island Public Utilities Commission, Docket No. 2290, The Narragansett Electric Company; testimony supporting proposed net salvage rates and depreciation rates.

South Carolina Public Service Commission, Docket No. 91-216-E, Duke Power Company; testimony supporting proposed depreciation rates.

South Dakota Public Utilities Commission, Docket No. EL14-106, NorthWestern Energy; testimony supporting revised depreciation rates.

Public Utilities Commission of the State of South Dakota, Case No. F-3062, Northern States Power Company; testimony concerning general financial requirements and measurements of financial performance.

Public Utilities Commission of the State of South Dakota, Case No. F-3188, Northern States Power Company; testimony concerning rate of return and general financial requirements.

Securities and Exchange Commission, File No. 3-5749, Northern States Power Company; testimony concerning the financial and ratemaking implications of an affiliation with Lake Superior District Power Company.

Tennessee Public Service Commission, Docket No. 89-11041, United Inter-Mountain Telephone Company; testimony concerning depreciation principles and capital recovery under competition.

The Railroad Commission of Texas, GUD Docket No. 9988, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10488, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10506, Texas Gas Service, testimony supporting recommended depreciation rates.

The Railroad Commission of Texas, GUD Docket No. 10526, Texas Gas Service, testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6596, Citizens Communications Company – Vermont Electric Division; testimony supporting recommended depreciation rates.

State of Vermont Public Service Board, Docket No. 6946 and 6988, Central Vermont Public Service Corporation; testimony supporting net salvage rates.

Commonwealth of Virginia State Corporation Commission, Case No. PUE-2002-00364, Washington Gas Light Company; testimony supporting proposed depreciation rates.

Public Service Commission of Wisconsin, Docket No. 2180-DT-3, General Telephone Company of Wisconsin; testimony concerning the equal-life group depreciation procedure.

**SPEAKER**

Depreciation Workshop, Oklahoma Corporation Commission, Public Utility Division, March 2015.

Depreciation Workshop, ONE Gas, Inc. January 2015.

Depreciation Training Seminar, Florida Public Service Commission, March 2013.

Depreciation and Obsolescence (Isness and Oughtness), Ninety-Fifth Annual Arizona Tax Conference, August 2012.

Group Depreciation Practices of Regulated Utilities (IAS 16 Property, Plant and Equipment), Hydro One Networks, Inc., November 2008.

Economics, Finance and Engineering Valuation. Florida Gulf Coast University, April 2007.

Depreciation Studies for Regulated Utilities, Hydro One Networks, Inc., April 2006.

Depreciation Studies for Cooperatives and Small Utilities. TELERGEE CFO and Controllers Conference, November, 2004.

Finding the “D” in RCNLD (Valuation Applications of Depreciation), Society of Depreciation Professionals Annual Meeting, September 2001.

Capital Asset and Depreciation Accounting, City of Edmonton Value Engineering Workshop, April 2001.

A Valuation View of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, October 1999.

Capital Recovery in a Changing Regulatory Environment, Pennsylvania Electric Association Financial-Accounting Conference, May 1999.

Depreciation Theory and Practice, Southern Natural Gas Company Accounting and Regulatory Seminar, March 1999.

Depreciation Theory Applied to Special Franchise Property, New York Office of Real Property Services, March 1999.

Capital Recovery in a Changing Regulatory Environment, PowerPlan Consultants Annual Client Forum, November 1998.

Economic Depreciation, AGA Accounting Services Committee and EEI Property Accounting and Valuation Committee, May 1998. Discontinuation of Application of FASB Statement No. 71, Southern Natural Gas Company Accounting Seminar, April 1998.

Forecasting in Depreciation, Society of Depreciation Professionals Annual Meeting, September 1997.

Economic Depreciation In Response to Competitive Market Pricing, 1997 TELUS Depreciation Conference, June 1997.

Valuation of Special Franchise Property, City of New York, Department of Finance Valuation Seminar, March 1997.

Depreciation Implications of FAS Exposure Draft 158-B, 1996 TLG Decommissioning Conference, October 1996.

Why Economic Depreciation?, American Gas Association Depreciation Accounting Committee Meeting, August 1995.

The Theory of Economic Depreciation, Society of Depreciation Professionals Annual Meeting, November 1994.

Vintage Depreciation Issues, G & T Accounting and Finance Association Conference, June 1994.

Pricing and Depreciation Strategies for Segmented Markets (Regulated and Competitive), Iowa State Regulatory Conference, May 1990.

Principles and Practices of Depreciation Accounting, Canadian Electrical Association and Nova Scotia Power Electric Utility Regulatory Seminar, December 1989.

Principles and Practices of Depreciation Accounting, Duke Power Accounting Seminar, September 1989.

The Theory and Practice of Depreciation Accounting Under Public Utility Regulation, GTE Capital Recovery Managers Conference, February 1989.

Valuation Methods for Regulated Utilities, GTE Capital Recovery Managers Conference, January 1988.

Depreciation Principles and Practices for REA Borrowers, NRECA 1985 National Accounting and Finance Conference, September 1985.

Depreciation Principles and Practices for REA Borrowers, Kentucky Association of Electric Cooperatives, Inc., Summer Accountants Association Meeting, June 1985.

Considerations in Conducting a Depreciation Study, NRECA 1984 National Accounting and Finance Conference, October 1984.

Software for Conducting Depreciation Studies on a Personal Computer, United States Independent Telephone Association, September 1984.

Depreciation—An Assessment of Current Practices, NRECA 1983 National Accounting and Finance Conference, September 1983

Depreciation—An Assessment of Current Practices, REA National Field Conference, September 1983.

An Overview of Depreciation Systems, Iowa State Commerce Commission, October 1982.

Depreciation Practices for Gas Utilities, Regulatory Committee of the Canadian Gas Association, September 1981.

Practice, Theory, and Needed Research on Capital Investment Decisions in the Energy Supply Industry, workshop, sponsored by Michigan State University and the Electric Power Research Institute, November 1977.

Depreciation Concepts Under Regulation, Public Utilities Conference, sponsored by The University of Texas at Dallas, July 1976.

Electric Utility Economics, Mid-Continent Area Power Pool, May 1974.

### **MODERATOR**

Depreciation Open Forum, Iowa State University Regulatory Conference, May 1991.

The Quantification of Risk and Uncertainty in Engineering Economic Studies, Iowa State University Regulatory Conference, May 1989.

Plant Replacement Decisions with Added Revenue from New Service Offerings, Iowa State University Regulatory Conference, May 1988.

Economic Depreciation, Iowa State University Regulatory Conference, May 1987.

Opposing Views on the Use of Customer Discount Rates in Revenue Requirement Comparisons, Iowa State University Regulatory Conference, May 1986.

Cost of Capital Consequences of Depreciation Policy, Iowa State University Regulatory Conference, May 1985.

Concepts of Economic Depreciation, Iowa State University Regulatory Conference, May 1984.

Ratemaking Treatment of Large Capacity Additions, Iowa State University Regulatory Conference, May 1983.

The Economics of Excess Capacity, Iowa State University Regulatory Conference, May 1982.

New Developments in Engineering Economics, Iowa State University Regulatory Conference, May 1980.

Training in Engineering Economy, Iowa State University Regulatory Conference, May 1979.

The Real Time Problem of Capital Recovery, Missouri Public Service Commission, Regulatory Information Systems Conference, September 1974.

### **HONORS AND AWARDS**

The Society of Sigma Xi.

Professional Achievement Citation in Engineering, Iowa State University, 1993.

**B2M LP**  
**Depreciation & Amortization Expenses**  
Historical Years (2015, 2016, 2017, 2018) and Bridge Year (2019)  
Year Ending December 31  
(\$ Millions)

Line No.	Particulars	2015		2016		2017		2018		2019	
		Deprn Rate	Provision								
		(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
<b><u>Depreciation Expenses</u></b>											
1	Major Fixed Assets	1.37%	7.2	1.37%	7.2	1.37%	7.2	1.37%	7.2	1.37%	7.2
2	Minor Fixed Assets	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0	0.00%	0.0
3	Depreciation on Fixed Assets		<u>7.2</u>								
4	Less Capitalized Depreciation		0.0		0.0		0.0		0.0		0.0
5	Asset Removal Costs		0.0		0.0		0.0		0.0		0.0
6	Losses/(Gains) on Asset Disposition		0.0		0.0		0.0		0.0		0.0
7	Total Depreciation Expenses		<u>7.2</u>								
<b><u>Amortization Expenses</u></b>											
8	Environmental Costs		0.0		0.0		0.0		0.0		0.0
9	Other Regulatory Amortization		0.0		0.0		0.0		0.0		0.0
10	Other Amortization		0.0		0.0		0.0		0.0		0.0
11	Total Amortization Expenses		<u>0.0</u>								
12	Total Depreciation & Amortization Expenses		<u>7.2</u>								
13	Exclude Other Reg Amort		0.0		0.0		0.0		0.0		0.0
14	Depreciation & Amortization for recovery		<u>7.2</u>								

**B2M LP**  
**Depreciation & Amortization Expenses**  
Test Year (2020)  
Year Ending December 31  
(\$ Millions)

Line No.	Particulars	2020	
		Deprn Rate	Provision
		(k)	(l)
	<b><u>Depreciation Expenses</u></b>		
1	Major Fixed Assets	1.30%	7.0
2	Minor Fixed Assets	0.00%	0.0
3	Depreciation on Fixed Assets		<u>7.0</u>
4	Less Capitalized Depreciation		0.0
5	Asset Removal Costs		<u>0.0</u>
6	Total Depreciation Expenses		<u>7.0</u>
	<b><u>Amortization Expenses</u></b>		
7	Environmental Costs		0.0
8	Other Regulatory Amortization		0.0
9	Other Amortization		0.0
10	Total Amortization Expenses		<u>0.0</u>
11	Total Depreciation & Amortization Expenses		<u>7.0</u>
12	Exclude Other Reg Amort		<u>0.0</u>
13	Depreciation & Amortization for recovery		<u>7.0</u>



17595 S. Tamiami Trail, Suite 260  
Fort Myers, Florida 33908  
T 239.267.1600 | M 239.980.5991

Ronald E. White, Ph.D.  
*President*

June 13, 2019

TRANSMITTED VIA E-MAIL

Mr. Arthur McGlashan  
Manager, Corporate Accounting  
HYDRO ONE NETWORKS INC.  
483 Bay Street  
Toronto, Ontario M5G 2P5

RE: Bruce-to-Milton Line

Dear Mr. McGlashan:

This correspondence is in response to your request for my professional opinion regarding a change in depreciation rates for the Bruce-to-Milton (B2M) transmission line. It is my understanding that consideration is being given to replacing current depreciation rates for B2M (estimated in a BU 215 study) with updated rates developed in a 2017 study for BU 210.

In formulating my opinion, I have considered: a) the size of the plant investments in B2M vs BU 210; b) the size of the depreciation reserves in B2M vs BU 210; and c) the difference between current B2M depreciation rates and 2017 BU 210 rates.

Based on my review, it is my opinion that, absent a specific need for maintaining unique B2M depreciation rates, any change in depreciation expense resulting from replacing current B2M depreciation rates with 2017 BU 210 rates would be minor. Aligning B2M rates with BU 210 rates avoids developing two sets of rates for like plant accounts in BU 210 depreciation studies.

It is my opinion, therefore, that replacing current B2M rates with 2017 BU 210 rates would be appropriate and consistent with the goals and objectives of depreciation accounting.

Please contact me if I can be of further assistance.

Respectfully,

A handwritten signature in black ink, appearing to read 'Ronald E. White', written over a horizontal line.

Ronald E. White, Ph.D.



<b>Members</b>	<b>Description</b>
Hydro One Indigenous Partnerships GP Inc. (“HOIP”) (formerly B2M GP Inc.)	A corporation owned indirectly by Hydro One Inc.
Saugeen Ojibway Nation Finance Corporation (“SON FC”) - Nominee for SON	A corporation owned directly by the First Nations
Hydro One B2M LP Inc.	A corporation owned indirectly by Hydro One Inc.

1

2 SON FC and its shareholders are not subject to payment in lieu of corporate tax (“PILS”)  
3 or Corporate Income Tax, as provided in EB-2015-0026 at Exhibit C1, Tab 5, Schedule  
4 1, Attachment 1-A and 1-B. Therefore, the taxable income in B2M LP allocated to SON  
5 FC will not be subject to income tax.

6

## 7 **2.2 DEPARTURE FROM PILS REGIME**

8

9 B2M LP is not a corporation exempt from tax under Section 149(1) of the *Income Tax*  
10 *Act* (Canada) and the *Taxation Act*, 2007 (Ontario), and is therefore not subject to  
11 payment in lieu of corporate income taxes (“PILS”) under the *Electricity Act*, 1998. B2M  
12 LP did not change tax regimes as a result of Hydro One’s Initial Public Offering (“IPO”)  
13 and was not subject to the deemed disposition rules under subsection 149(10) of the  
14 *Income Tax Act* or where the tax basis of assets in B2M LP was revalued for tax  
15 purposes.

16

## 17 **2.3 REGULATORY INCOME TAX EXPENSE**

18

19 Regulatory Income Taxes for B2M LP are determined by applying the statutory tax rate  
20 to the regulatory taxable income allocated to Hydro One Indigenous Partnerships GP Inc.  
21 and Hydro One B2M LP Inc.

Witness: Nancy Tran

1 **2.4 CORPORATE MINIMUM TAX**

2  
3 Ontario corporate minimum tax (“OCMT”) is designed to impose a minimum tax based  
4 on financial statement income calculated without most tax adjustments. The OCMT paid  
5 in the year can be applied to reduce taxes payable in future year. Hydro One Indigenous  
6 Partnerships GP Inc. and Hydro One B2M LP Inc. were subject to OCMT in the  
7 historical years 2015 to 2018 as shown in Exhibit F, Tab 6, Schedule 1, Attachment 3.  
8 B2M LP recovered the OCMT expense from customers in the historical years and will  
9 reduce income tax expenses in the Test period 2020 to 2024 by the amount of OCMT  
10 credits that can be utilized to reduce taxes payable in those years. These credits are  
11 expected to be fully depleted prior to the end of the Test period, resulting in an increase  
12 to the overall tax expense.

13  
14 **2.5 INCOME TAX RATE (FEDERAL AND ONTARIO)**

15  
16 A combined income tax rate of 26.5% has been used for the 2020 Test Year, as set out in  
17 Table 1 below, comprising a federal rate of 15% and a provincial rate of 11.5%. Any  
18 variance between actual taxes payable and forecast taxes, because of tax policy and  
19 legislation changes or rate changes for income tax or capital cost allowance, will be  
20 captured in a deferral account for tax rate changes as per Section 7.1 of the Electricity  
21 Distribution Rate (“EDR”) Handbook, described further in Exhibit H, Tab 1, Schedule 1.

22  
23 **Table 1 - Combined Income Tax Rates**

	Historical				Bridge	Test
	2015	2016	2017	2018	2019	2020
Federal Tax Rate (%)	15.00	15.00	15.00	15.00	15.00	15.00
Provincial Rate (%)	11.50	11.50	11.50	11.50	11.50	11.50
Total Statutory Tax Rate (%)	<b>26.50</b>	<b>26.50</b>	<b>26.50</b>	<b>26.50</b>	<b>26.50</b>	<b>26.50</b>

Witness: Nancy Tran

1    **3. RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE**  
2    **TAX AND TAXABLE INCOME**

3  
4    Reconciliation between the regulatory net income before tax (“NIBT”) and taxable  
5    income for the 2020 Test year is provided in Exhibit F, Tab 6, Schedule 1, Attachment 1.  
6    This schedule contains the income tax computation and also shows how the taxable  
7    income is computed by making adjustments to the regulatory NIBT for items such as  
8    depreciation and capital cost allowance (“CCA”). The calculation of CCA is provided in  
9    Exhibit F, Tab 6, Schedule 1, Attachment 2.

10  
11    CCA is calculated on a declining balance and, as a result, the amount of CCA available to  
12    reduce taxable income decreases. This is illustrated in the calculation of CCA for the  
13    historical years in Exhibit F, Tab 6, Schedule 1, Attachment 4, which shows the CCA  
14    deductions declining from \$29M in 2015 to \$21M in 2019. The rate of decline is  
15    expected to continue in the Test years and will result in higher tax expense over the Test  
16    period.

17  
18    Reconciliation between the accounting NIBT and taxable income for the historical years  
19    2015-2018 is provided in Exhibit F, Tab 6, Schedule 1, Attachment 3. The calculation of  
20    CCA for the historical years is provided in Exhibit F, Tab 6, Schedule 1, Attachment 4.

21  
22    To make it easier to follow these reconciliations, B2M LP has placed these adjustments  
23    into the following categories:

- 24       1. Recurring items that must be added (deducted) because they have been included  
25       in the OM&A expenses in arriving at the revenue requirement, or for which  
26       appropriate tax adjustments are made (for example, depreciation versus CCA);  
27       and  
28       2. Recurring items not in the revenue requirement.

Witness: Nancy Tran

1 **4. OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME**

2  
3 The starting point for the computation of B2M LP taxable income is the NIBT as shown  
4 on the utility's income statement for the year. The NIBT is prepared by using U.S.  
5 Generally Accepted Accounting Principles, but taxable income is computed using the  
6 relevant tax legislation, interpretations and assessing practices. Therefore, many  
7 adjustments are typically made to the NIBT to arrive at taxable income. Essentially, the  
8 NIBT is increased by amounts that are not deductible for tax purposes, such as  
9 depreciation. On the other hand, the NIBT is reduced by amounts that are deductible for  
10 tax purposes but have not been deducted in computing NIBT such as CCA.

11  
12 Consequently, it is imperative that the NIBT be adjusted for amounts that have been  
13 included (or deducted) for accounting purposes that are not income (or deductible) for tax  
14 return purposes.

15  
16 **5. TAXABLE TREATMENT OF DEFERRAL ACCOUNTS (REGULATORY**  
17 **ASSETS AND LIABILITIES)**

18  
19 Deferral accounts are typically recognized by the utilities' balance sheets for forgone  
20 revenue or for expenses that have been incurred, for which recovery will be sought from  
21 ratepayers through future rates. Disposition of the deferral accounts is determined by the  
22 Board.

23  
24 For example, as shown in Table 2, assuming that a 26.5% tax rate and a \$100 expense is  
25 incurred, the utility will be allowed to deduct the \$100 in computing taxable income for  
26 the year in which the expense has been incurred. If the OEB subsequently approves  
27 recovery of this expense over a two-year period through a rate rider, the utility will  
28 include the approved recoverable amounts in computing taxable income for the year in

Witness: Nancy Tran

1 which it is billed to ratepayers. The net result is that the utility has recovered the \$100  
2 cost although the income or expense has been taxed or deducted in different years.

3  
4 **Table 2 - Example of the Income Tax Treatment of Deferral Account Disposition**

	<b>Year 1</b>	<b>Year 2</b>	<b>Year 3</b>	<b>CUM</b>
<b>Income (deduction)</b>	(100)	50	50	Nil
<b>Tax Refund (payable)</b>	26.5	(13.25)	(13.25)	Nil
<b>Cash Inflow (outflow)</b>	(73.5)	36.75	36.75	Nil

5 Therefore, deferral accounts have not been included in computing tax payable for  
6 purposes of the revenue requirement since the tax benefit has or will be obtained through  
7 the tax system. It should be noted that this conclusion is consistent with the Section  
8 2.8.11 of the Filing Requirements issued February 11, 2016 which states:

9  
10 *“Regulatory assets (and regulatory liabilities) must generally be excluded*  
11 *from PILs calculations both when they were created, and when they were*  
12 *collected, regardless of the actual tax treatment accorded those amounts.”*

13  
14 **6. INTEGRITY CHECKS**

15  
16 B2M LP has performed the integrity checks set described in Section 2.8.11.2 of the Filing  
17 Requirements.

18  
19 **7. SUPPORTING ATTACHMENTS**

20  
21 The attachments supporting the determination of the income tax expense are provided in  
22 the following attachments:

Witness: Nancy Tran

- 1 **Attachment 1:** Calculation of Utility Income Taxes – Bridge and Test Year
- 2 **Attachment 2:** Calculation of Capital Cost Allowance – Bridge and Test Year
- 3 **Attachment 3:** Calculation of Utility Income Taxes - Historical Years
- 4 **Attachment 4:** Calculation of Capital Cost Allowance - Historical Years

B2M LP  
Calculation of Utility Income Taxes  
Bridge (2019) and Test Years (2020)  
Year Ending December 31  
(\$ Millions)

<b>SUMMARY OF TAX EXPENSE</b>		
	2019	2020
Hydro One Indigenous Partnerships GP Inc	1.05	0.98
Hydro One B2M LP Inc.	0.00	0.00
SON FC	0.00	0.00
<b>Total</b>	<b>1.05</b>	<b>0.99</b>

**B2M LP**

Line No.	Particulars	2019 (a)	2020 (b)
	<u>Determination of Taxable Income</u>		
1	Regulatory Net Income (before tax)	18.85	18.58
2	Book to Tax Adjustments:		
3	Depreciation and amortization	7.20	6.99
4	Capital Cost Allowance	-21.31	-19.53
5	Other	1.91	0.00
6	Total Adjustments	-12.21	-12.54
7	<b>Regulatory Taxable Income/(Loss) before Loss Carry Forward</b>	<b>\$ 6.64</b>	<b>\$ 6.04</b>
	<u>Allocation of Taxable Income</u>		
8	Hydro One Indigenous Partnerships GP Inc	4.73	4.31
9	Hydro One B2M LP Inc.	0.01	0.01
10	SON FC	1.91	1.73
11	Total	<b>\$ 6.64</b>	<b>\$ 6.04</b>
	<u>Tax Rates</u>		
12	Federal Tax	15.00 %	15.00 %
13	Provincial Tax	11.50 %	11.50 %
14	Total Tax Rate	<b>26.50 %</b>	<b>26.50 %</b>

Hydro One Indigenous Partnerships GP Inc

Line No.	Particulars	2019 (a)	2020 (a)
	<u>Determination of Income Taxes</u>		
1	Allocation of Taxable Income from B2M LP	4.73	4.31
2	Loss Carryforward	<u>0.00</u>	<u>0.00</u>
3	Taxable Income after loss carryforward	4.73	4.31
4	Tax Rate	26.50 %	26.50 %
5	<b>Income Tax Expense</b>	<b>\$ <u>1.25</u></b>	<b>\$ <u>1.14</u></b>
	<u>Loss Continuity Schedule</u>		
6	Closing Losses Carryforward	0.00	0.00
7	Losses (Incurred)/Utilized during the year	<u>0.00</u>	<u>0.00</u>
8	Closing Losses Carryforward	0.00	0.00
	<u>Determination of Corporate Minimum Tax</u>		
9	Allocation of Accounting Income from B2M LP	12.75	12.55
10	Corporate Minimum Tax Rate	<u>2.70 %</u>	<u>2.70 %</u>
11	Corporate Minimum Tax Potentially Applicable	0.34	0.34
12	Ontario Income Tax	<u>0.54</u>	<u>0.50</u>
13	<b>Corporate Minimum Tax Payable (Utilized)</b>	<b>\$ <u>-0.20</u></b>	<b>\$ <u>-0.16</u></b>
14	Opening CMT Credit Carryforward	1.24	1.04
15	CMT Credit Incurred/(utilized)	<u>-0.20</u>	<u>-0.16</u>
16	Closing CMT Credit Carryforward	1.04	0.88
17	<b>Total Taxes Expense for Hydro One Indigenous Partnerships GP Inc.</b>	<b>\$ <u>1.05</u></b>	<b>\$ <u>0.98</u></b>

**Hydro One B2M LP Inc.**

Line No.	Particulars	2019 (a)	2020 (a)
<u>Determination of Income Taxes</u>			
1	Allocation of Taxable Income from B2M LP	0.01	0.01
2	Loss Carryforward	<u>0.00</u>	<u>0.00</u>
3	Taxable Income after loss carryforward	0.01	0.01
4	Tax Rate	<u>26.50 %</u>	<u>26.50 %</u>
5	Sub Total	0.00	0.00
6	Additional Taxes due to Negative ACB	0.00	0.00
7	<b>Income Tax Expense</b>	<b>\$ <u>0.00</u></b>	<b>\$ <u>0.00</u></b>
<u>Loss Continuity Schedule</u>			
8	Closing Losses Carryforward	0.00	0.00
9	Losses (Incurred)/Utilized during the year	<u>0.00</u>	<u>0.00</u>
10	Closing Losses Carryforward	0.00	0.00
<u>Determination of Corporate Minimum Tax</u>			
11	Allocation of Accounting Income from B2M LP	0.02	0.02
12	Corporate Minimum Tax Rate	<u>2.70 %</u>	<u>2.70 %</u>
13	Corporate Minimum Tax Potentially Applicable	0.00	0.00
14	Ontario Income Tax	0.00	0.00
15	<b>Corporate Minimum Tax Payable (Utilized)</b>	<b>\$ <u>0.00</u></b>	<b>\$ <u>0.00</u></b>
16	Opening CMT Credit Carryforward	0.00	0.00
17	CMT Credit Incurred/(utilized)	<u>0.00</u>	<u>0.00</u>
18	Closing CMT Credit Carryforward	0.00	0.00
19	<b>Total Taxes Expense for Hydro One B2M LP Inc</b>	<b>\$ <u>0.00</u></b>	<b>\$ <u>0.00</u></b>

**SON FC**

Line No.	Particulars	2019 (a)	2020 (a)
<u>Determination of Income Taxes</u>			
1	Allocation of Taxable Income from B2M LP	1.91	1.73
2	Tax Rate	0.00 %	0.00 %
3	<b>Income Tax Expense</b>	<b>\$ 0.00</b>	<b>\$ 0.00</b>
<u>Determination of Corporate Minimum Tax</u>			
4	Allocation of Accounting Income from B2M LP	6.09	6.02
5	Corporate Minimum Tax Rate	0.00 %	0.00 %
6	<b>Corporate Minimum Tax Payable</b>	<b>\$ 0.00</b>	<b>\$ 0.00</b>
7	<b>Total Taxes Expense for SON FC</b>	<b>\$ 0.00</b>	<b>\$ 0.00</b>

B2M LP  
Calculation of Capital Cost allowance (CCA)  
Bridge (2019) and Test Years (2020)  
Year Ending December 31  
(\$ Millions)

2019	<u>Opening</u>	Net	<u>UCC pre-1/2</u>	<u>50% net</u>	<u>UCC for CCA</u>	<u>CCA Rate</u>	<u>CCA</u>	Accelerated	<u>Closing UCC</u>
<u>CCA Class</u>	<u>UCC</u>	<u>Additions</u>	<u>yr</u>	<u>additions</u>				<u>CCA Incentive</u>	
1	2.71	-	2.71	-	2.71	0.04	0.11	-	2.60
14.1 (Pre-2017)*	50.84	-	50.84	-	50.84	0.07	3.56	-	47.28
14.1 (Post-2017)*	-	0.06	0.06	(0.03)	0.03	0.05	0.00	0.00	0.06
47	216.06	2.96	219.02	(1.48)	217.54	0.08	17.40	0.24	201.38
UCC	269.61	3.02	272.64	(1.51)	271.12	0.24	21.07	0.24	251.32

**TOTAL CCA** 21.31

2020	<u>Opening</u>	Net	<u>UCC pre-1/2</u>	<u>50% net</u>	<u>UCC for</u>	<u>CCA Rate</u>	<u>CCA</u>	Accelerated	<u>Closing UCC</u>
<u>CCA Class</u>	<u>UCC</u>	<u>Additions</u>	<u>yr</u>	<u>additions</u>	<u>CCA</u>			<u>CCA Incentive</u>	
1	2.60	-	2.60	-	2.60	0.04	0.10	-	2.50
14.1 (Pre-2017)*	47.28	-	47.28	-	47.28	0.07	3.31	-	43.97
14.1 (Post-2017)*	0.06	-	0.06	-	0.06	0.05	0.00	-	0.05
47	201.38	-	201.38	-	201.38	0.08	16.11	-	185.27
UCC	251.32	-	251.32	-	251.32	0.24	19.53	-	231.80

**TOTAL CCA** 19.53

**Note:**

\* The Eligible Capital Expenditures (ECE) was transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027

B2M LP  
Calculation of Utility income Tax  
2015 - 2018 Historical Years  
Year Ending December 31  
(\$ Millions)

Tax Expense	2015	2016	2017	2018	Ownership Percentage
Hydro One Indigenous Partnerships GP Inc.	0.63	0.31	0.30	0.67	65.71%
Hydro One B2M LP Inc.	0.00	0.00	0.00	0.00	0.10%
SON FC	-	-	-	-	34.19%
<b>Total</b>	<b>0.63</b>	<b>0.31</b>	<b>0.30</b>	<b>0.67</b>	<b>100%</b>

**B2M LP**

Line No.	Particulars	2015	2016	2017	2018
	<u>Determination of Taxable Income</u>				
1	Net Income before Tax	29.40	17.13	16.66	19.32
	<u>Recurring items included in Revenue Requirement (RR):</u>				
2	Permanent differences	0.10	0.12	(0.01)	-
3	Depreciation and amortization	7.17	7.17	7.17	7.17
4	Capital Cost Allowance	(29.01)	(26.74)	(24.65)	(22.73)
5	Regulatory asset - transitional recovery	(7.70)	1.93	1.93	1.93
6	Other	(0.12)	(0.04)	(0.04)	(0.04)
	<u>Recurring items included not part of RR:</u>				
7	Regulatory asset - foregone revenue			(1.13)	2.77
8	Total Adjustments	(29.55)	(17.57)	(16.74)	(10.91)
9	Taxable Income/(Loss) before Loss Carryforward	(0.15)	(0.44)	(0.08)	8.42
	<u>Allocation of Taxable Income</u>				
11	Hydro One Indigenous Partnerships GP Inc.	0.38	(0.14)	(0.02)	5.57
12	Hydro One B2M LP Inc.	0.00	(0.00)	(0.00)	0.01
13	SON FC	(0.54)	(0.30)	(0.06)	2.84
14	Total	(0.15)	(0.44)	(0.08)	8.42

Hydro One Indigenous Partnerships GP Inc.

Line No.	Particulars	2015	2016	2017	2018
<u>Determination of Income Taxes</u>					
1	Net Income before Tax	(0.03) *	0.08	0.05	0.06
<u>Recurring items included in Revenue Requirement (RR):</u>					
2	Allocation of Taxable Income from B2M LP	0.38	(0.14)	(0.02)	5.57
3	Loss Carryforward - included	-	0.14	0.02	(1.03)
<u>Recurring items included not part of RR:</u>					
4	Deduction under 20(1)(j)	-	(1.26)	(1.25)	(1.28)
5	Loss Carryforward - excluded (non regulated activities)	-	1.19	1.20	(1.16)
6	Taxable Income after loss carryforward	0.35	-	-	2.15
7	Tax Rate	26.5%	26.5%	26.5%	26.5%
8	<b>Income Tax Expense</b>	<b>0.09</b>	<b>-</b>	<b>-</b>	<b>0.57</b>
16	<b>Corporate Minimum Tax Payable</b>	<b>0.53</b>	<b>0.31</b>	<b>0.30</b>	<b>0.10</b>
17	<b>Total Taxes Expense for Hydro One Indigenous Partnerships GP Inc.</b>	<b>0.63</b>	<b>0.31</b>	<b>0.30</b>	<b>0.67</b>
<u>Loss Continuity Schedule</u>					
9	Opening Loss Carryforward - included in RR	(0.87)	(0.87)	(1.01)	(1.03)
10	Losses (Incurred)/Utilized during the year	-	(0.14)	(0.02)	1.03
11	Closing Loss Carryforward - included in RR	(0.87)	(1.01)	(1.03)	-
12	Opening Loss Carryforward - excluded in RR	0.87	0.87	0.04	(1.16)
13	Losses (Incurred)/Utilized during the year	-	(1.19)	(1.20)	1.16
14	Losses carried back to prior years	-	0.35	-	-
15	Closing Loss Carryforward - excluded in RR	0.87	0.04	(1.16)	-
<u>Corporate Minimum Tax Carryforward</u>					
	Opening CMT Credit Carryforward	-	0.53	0.84	1.14
	CMT Paid/(CMT credit Utilized)	0.53	0.31	0.30	0.10
	Ending CMT Credit Carryforward	0.53	0.84	1.14	1.24

\* Information is based on the short taxation year ended December 31, 2015 as a result of the IPO

Hydro One B2M LP Inc

Line No.	Particulars	2015	2016	2017	2018
<u>Determination of Income Taxes</u>					
1	Net Income before Tax	-	-	0.00	0.00
<u>Recurring items included in Revenue Requirement (RR):</u>					
2	Allocation of Taxable Income from Hydro One B2M LP	0.00	(0.00)	(0.00)	0.01
3	Loss Carryforward - included	-	0.00	0.00	-
<u>Recurring items included not part of RR:</u>					
4	Deduction under 20(1)(j)	-	(0.00)	(0.00)	(0.00)
5	Loss Carryforward - excluded	-	0.00	0.00	(0.00)
6	Taxable Income after loss carryforward	0.00	-	-	0.00
7	Tax Rate	26.5%	26.5%	26.5%	26.5%
8	<b>Income Tax Expense</b>	<b>0.00</b>	<b>-</b>	<b>-</b>	<b>0.00</b>
<u>Loss Continuity Schedule</u>					
9	Opening Loss Carryforward - included in RR	(0.03)	(0.03)	(0.03)	(0.03)
10	Losses (Incurred)/Utilized during the year	-	(0.00)	(0.00)	-
11	Closing Loss Carryforward - included in RR	(0.03)	(0.03)	(0.03)	(0.03)
12	Opening Loss Carryforward - excluded in RR	-	-	(0.00)	(0.00)
13	Losses (Incurred)/Utilized during the year	-	(0.00)	(0.00)	0.00
14	Losses carried back to prior years	-	0.00	-	-
15	Closing Loss Carryforward - excluded in RR	-	(0.00)	(0.00)	-
16	<b>Corporate Minimum Tax Payable</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b> (1)
17	<b>Total Taxes Expense for Hydro One B2M LP Inc.</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>	<b>0.00</b>

**SON FC**

Line No.	Particulars	2015	2016	2017	2018
	<u>Determination of Income Taxes</u>				
1	Allocation of Taxable Income from Hydro One B2M LP	(0.54)	(0.30)	(0.06)	2.84
2	Tax Rate	0.0%	0.0%	0.0%	0.0%
3	Sub Total	-	-	-	-
4	<b>Income Tax Expense</b>	-	-	-	-

Note (1) - Corporate Minimum Tax is included in the B2M rate applications in 2015-2018

B2M LP  
 Calculation of Capital Cost allowance (CCA)  
 Historical Years (2015 - 2018)  
 Year Ending December 31  
 (\$ Millions)

2015	CCA Class	Opening UCC	Net Additions	Transfers	Net Adjustments	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
	1	3.2	-	-	-	3.2	-	3.2	4%	0.1	3.1
	12	0.0	-	-	-	0.0	-	0.0	100%	0.0	-
	47	301.6	-	-	-	301.6	-	301.6	8%	24.1	277.5
	UCC	304.8	-	-	-	304.8	-	304.8		24.3	280.5
CEC Continuity		68.1	-	-	(0.1)	68.0	-	68.0	7%	4.8	63.2
<b>TOTAL CCA and ECE</b>										<b>29.0</b>	
2016	CCA Class	Opening UCC	Net Additions	Transfers	Net Adjustments	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
	1	3.1	-	-	-	3.1	-	3.1	4%	0.1	2.9
	12	-	-	-	-	-	-	-	100%	-	-
	47	277.5	-	-	-	277.5	-	277.5	8%	22.2	255.3
	UCC	280.5	-	-	-	280.5	-	280.5		22.3	258.2
CEC Continuity		63.2	-	-	-	63.2	-	63.2	7%	4.4	58.8
<b>TOTAL CCA and ECE</b>										<b>26.7</b>	
2017	CCA Class	Opening UCC	Net Additions	Transfers	Net Adjustments	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
	1	2.9	-	-	-	2.9	-	2.9	4%	0.1	2.8
	12	-	-	-	-	-	-	-	100%	-	-
	14.1 (ECE) **	58.8	-	-	-	58.8	-	58.8	7%	4.1	54.7
	47	255.3	-	-	-	255.3	-	255.3	8%	20.4	234.8
	UCC	317.0	-	-	-	317.0	-	317.0		24.7	292.3
<b>TOTAL CCA</b>										<b>24.7</b>	
2018	CCA Class	Opening UCC	Net Additions	Transfers	Net Adjustments	UCC pre-1/2 yr	50% net additions	UCC for CCA	CCA Rate	CCA	Closing UCC
	1	2.8	-	-	-	2.8	-	2.8	4%	0.1	2.7
	12	-	-	-	-	-	-	-	100%	-	-
	14.1 (ECE) **	54.7	-	-	-	54.7	-	54.7	7%	3.8	50.8
	47	234.8	-	-	-	234.8	-	234.8	8%	18.8	216.1
	UCC	292.3	-	-	-	292.3	-	292.3		22.7	269.6
<b>TOTAL CCA</b>										<b>22.7</b>	

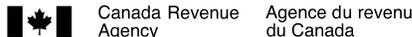
**Note:**

\*\* The Eligible Capital Expenditures (ECE) was transferred to Class 14.1 for taxation years beginning January 1, 2017. The CCA rate will remain at 7% for tax years that end prior to 2027

1  
2  
3

**INCOME TAX RETURN**

Attachment 1: Federal and Ontario Income Tax Return



# Partnership Financial Return

Exhibit F-7-1  
Attachment 1  
Page 1 of 34

Protected B when completed

**T5013**  
**Financial**

Full disclosure is required on all documents relating to this return. All the information requested in this form and in the documents supporting your information return is "prescribed information".

Complete this financial return using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account at [canada.ca/my-cra-business-account](http://canada.ca/my-cra-business-account). Your authorized representative can access this service in Represent a Client at [canada.ca/taxes-representatives](http://canada.ca/taxes-representatives).

**Note:** All legislative references provided on this form are from the Income Tax Act.

**055**  
**For office use only**

## Identification

<b>001</b> Partnership account number 80820 9530 RZ0001		<b>040</b> Is this an amended return? <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No											
<b>006</b> Partnership name: B2M LIMITED PARTNERSHIP		<b>060</b> Fiscal period to which this information return applies: Fiscal period start Year Month Day <b>061</b> Fiscal period end * Year Month Day From 2018-01-01 to 2018-12-31											
<b>007</b>		* If you answer <b>Yes</b> to question 078 below, enter the date when the partnership ceased to exist.											
<b>008</b> Partnership operating or trading name: B2M LIMITED PARTNERSHIP		<b>062</b> The end members of this partnership are (tick the applicable boxes): 01 <input checked="" type="checkbox"/> Individuals (including trusts) 02 <input checked="" type="checkbox"/> Corporations											
<b>009</b>		<b>070</b> Is this the first year of filing? <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No If <b>Yes</b> , enter the date the partnership was created: <b>071</b> _____											
<b>010</b> Location of the partnership head office Has this location changed since the last time you filed a partnership information return? <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No If <b>Yes</b> , enter the address of the new location on lines 011 to 018: <b>011</b> <b>012</b>		<b>073</b> Number of T5013 slips: 3											
<b>015</b> City Province/State <b>016</b>		<b>078</b> Is this the partnership's final information return up to dissolution? <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No											
<b>017</b> Country Postal or ZIP code <b>018</b>		<b>079</b> If an election was made under section 261 by one or more partners, state the functional currency code used for this return: _____											
<b>020</b> Mailing address of the partnership (if different from the head office address) Has this address changed since the last time you filed a partnership information return? <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No If <b>Yes</b> , enter the new mailing address on lines 021 to 028: <b>021</b> c/o <b>023</b> <b>024</b>		<b>082</b> Was the partnership a Canadian partnership throughout the fiscal period? <input checked="" type="checkbox"/> 1 Yes <input type="checkbox"/> 2 No											
<b>025</b> City Province/State <b>026</b>		<b>086</b> Type of partnership at the end of the fiscal period											
<b>027</b> Country Postal or ZIP code <b>028</b>		<table border="0"> <tr> <td><b>Non tax shelter</b></td> <td><b>Tax shelter (TS)</b></td> </tr> <tr> <td><input type="checkbox"/> 01 General partnership</td> <td><input type="checkbox"/> 11 General partnership</td> </tr> <tr> <td><input checked="" type="checkbox"/> 02 Limited partnership</td> <td><input type="checkbox"/> 12 Limited partnership</td> </tr> <tr> <td><input type="checkbox"/> 03 Limited liability partnership</td> <td><input type="checkbox"/> 13 Co-ownership</td> </tr> <tr> <td><input type="checkbox"/> 08 Investment club</td> <td><input type="checkbox"/> 19 Other (specify below)</td> </tr> </table>		<b>Non tax shelter</b>	<b>Tax shelter (TS)</b>	<input type="checkbox"/> 01 General partnership	<input type="checkbox"/> 11 General partnership	<input checked="" type="checkbox"/> 02 Limited partnership	<input type="checkbox"/> 12 Limited partnership	<input type="checkbox"/> 03 Limited liability partnership	<input type="checkbox"/> 13 Co-ownership	<input type="checkbox"/> 08 Investment club	<input type="checkbox"/> 19 Other (specify below)
<b>Non tax shelter</b>	<b>Tax shelter (TS)</b>												
<input type="checkbox"/> 01 General partnership	<input type="checkbox"/> 11 General partnership												
<input checked="" type="checkbox"/> 02 Limited partnership	<input type="checkbox"/> 12 Limited partnership												
<input type="checkbox"/> 03 Limited liability partnership	<input type="checkbox"/> 13 Co-ownership												
<input type="checkbox"/> 08 Investment club	<input type="checkbox"/> 19 Other (specify below)												
<b>030</b> Location of the partnership's books and records (if different from the head office address) Has this location changed since the last time you filed a partnership information return? <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No If <b>Yes</b> , enter the address of the new location on lines 031 to 038: <b>031</b> <b>032</b>		<b>087</b> If the partnership is a tax shelter (TS), enter the TS identification number: _____											
<b>035</b> City Province/State <b>036</b>		<b>098</b> Industry code (NAICS): 221121											
<b>037</b> Country Postal or ZIP code <b>038</b>													



Protected B when completed

	<b>Fiscal period end</b>	
<b>Partnership account number</b>	Year Month Day	
001 80820 9530 RZ0001	2018-12-31	061

**Documents required to be attached to this T5013 FIN, Partnership Financial Return**

1. The T5013 Summary, Summary of Partnership Income, and a copy of the T5013, Statement of Partnership Income, issued to partners and nominees or agents.
2. The GIF1 schedules; 100, 125, 140 (when more than one schedule 125 is filed), and schedule 141 which is not required for investment clubs.
3. Schedule 1 (if you are an inactive partnership, see line 280 in Guide T4068 for more information) and Schedule 50.
4. Answer all of the following questions. For each **Yes** response, **attach** the schedule to the partnership return, unless otherwise instructed.

		<b>Schedule or form</b>
At any time during the fiscal period, was the partnership a member (directly, or indirectly through one or more partnerships) of another partnership?	<b>150</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	9
Has the partnership had any transactions, including sections 97 and 98, and subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents.	<b>162</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	T2058, T2059, and/or T2060
Did the partnership have a total amount over \$1 million of reportable transactions with non-arm's length non-residents?	<b>171</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	T106
Is the partnership required to file Form T1134 in respect of any foreign affiliates in the fiscal period?	<b>172</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property, gifts of medicine, or federal, provincial, territorial, or municipal political contributions?	<b>202</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	2
Does the partnership have a permanent establishment in more than one jurisdiction?	<b>205</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	<b>206</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	6
Does the partnership have any property that is eligible for capital cost allowance?	<b>208</b> <input checked="" type="checkbox"/> 1 Yes <input type="checkbox"/> 2 No	8
Does the partnership have any resource-related deductions (excluding renounced expenditures)?	<b>212</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	12
Is the partnership allocating any investment tax credits (ITCs)? If <b>Yes</b> , attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	<b>231</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	<b>232</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	T661
Did the partnership allocate renounced resource expenses to its members?	<b>252</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	52
Did the partnership own or hold specified foreign property where the total cost amount of all such property, at any time in the fiscal period, was more than CAN\$100,000?	<b>259</b> <input type="checkbox"/> 1 Yes <input checked="" type="checkbox"/> 2 No	T1135

Protected B when completed

	Fiscal period end
<b>Partnership account number</b> 80820 9530 RZ0001	Year Month Day 2018-12-31

**Additional information**

Did the partnership use the international financial reporting standards (IFRS) when it prepared its financial statements? **270**  1 Yes  2 No

Was a slip issued to one or more nominees or agents? **271**  1 Yes  2 No

Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2? **272**  1 Yes  2 No

Does the partnership have one or more new nominees or agents? **273**  1 Yes  2 No

Did the partnership allocate any amount of income tax deducted at source? **274**  1 Yes  2 No

Did the partnership make any other election(s) under the Act during the fiscal period? If **Yes**, attach a copy of each election form to this return. **275**  1 Yes  2 No

Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed? If **Yes**, provide the business number(s) of the predecessor partnership(s): **277**  1 Yes  2 No

**278**

**279**

Was the partnership inactive throughout the fiscal period this information return applies to? If **Yes**, see Guide T4068 to verify your filing requirements. **280**  1 Yes  2 No

Did members of the partnership immigrate to Canada during the fiscal period? **291**  1 Yes  2 No

Did members of the partnership emigrate from Canada during the fiscal period? **292**  1 Yes  2 No

If the major business activity is construction, did you have any subcontractors during the fiscal period? **295**  1 Yes  2 No

Did the partnership report its farming or fishing income using the cash method? **296**  1 Yes  2 No

Is this a publicly traded partnership? **297**  1 Yes  2 No

If **Yes**, did the partnership issue T5008 information slips to report transactions of interests in the partnership? **298**  1 Yes  2 No

**Miscellaneous information**

Was an NR4 information return for tax deductions withheld at source filed for the fiscal period? **301**  1 Yes  2 No

If **Yes**, provide the non-resident account number: **302**

If **Yes**, were NR4 slips issued? **303**  1 Yes  2 No

Is this partnership a specified investment flow-through (SIFT) partnership? **304**  1 Yes  2 No

If **Yes**, enter the taxable non-portfolio earnings for the fiscal period: **305**

If **Yes**, enter the tax payable under Part IX.1 for the fiscal period: **306**

Enter the amount of the late filing penalty from line 307 of Schedule 52. **307**

Amount of payment enclosed with this return: **308**

Protected B when completed

<b>001</b>	<b>Partnership account number</b>	<b>061</b>	<b>Fiscal period end</b>
	80820 9530 RZ0001		Year Month Day 2018-12-31

**Additional information for all partnerships (including tax shelters that are partnerships)**

Name and identification number of the partner designated under subsection 165(1.15) of the Act

<b>400</b>	HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.	<b>402</b>	818381840RC0001
	Name of designated partner		Identification number

**Additional information for tax shelters only**

Principal promoter

<b>500</b>	<b>501</b>	<b>502</b>
Last name (print)	First name (print)	Identification number

**Certification**

I, <b>950</b>	TRAN	<b>951</b>	NANCY	<b>954</b>	VP CORPORATE TAX
	Last name (print)		First name (print)		Position or title

certify that the information given on this form is correct and complete. I further certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as specifically disclosed in a statement attached to this return.

<b>955</b>	2019-03-29	<b>956</b>	(416) 345-6778
	Year Month Day		Telephone number

**Language of correspondence**

Indicate your language of correspondence: **990**  1 English  2 French

Personal information is collected under the Income Tax Act to administer tax, benefits, and related programs. It may also be used for any purpose related to the enforcement of the Act such as audit, compliance and collection activities. It may be shared or verified with other federal, provincial, territorial or foreign government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the Privacy Act, individuals have the right to access their personal information, request correction, or file a complaint to the Privacy Commissioner of Canada regarding the handling of the individual's personal information. Refer to Personal Information Bank CRA PPU 224 on Info Source at [canada.ca/cra-info-source](http://canada.ca/cra-info-source).

**PARTNERSHIP'S BALANCE SHEET INFORMATION**

**T5013  
SCHEDULE 100**

Partnership name B2M LIMITED PARTNERSHIP	Partnership account Number 80820 9530 RZ0001	Fiscal period end Year Month Day 2018-12-31	Original <input checked="" type="checkbox"/> Amended <input type="checkbox"/>
---	---	---	--

Is this a NIL schedule? ..... **999** Yes  No

**Balance sheet information**

Account	Description	GIFI	Current year	Prior year
<b>Assets</b>				
	Total current assets	<b>1599</b> +	14,696,000.00	11,744,000.00
	Total tangible capital assets	<b>2008</b> +	526,448,000.00	526,448,000.00
	Total accumulated amortization of tangible capital assets	<b>2009</b> -	28,977,000.00	21,805,000.00
	Total intangible capital assets	<b>2178</b> +		
	Total accumulated amortization of intangible capital assets	<b>2179</b> -		
	Total long-term assets	<b>2589</b> +		1,925,000.00
	* Assets held in trust	<b>2590</b> +		
	<b>Total assets</b> (mandatory field)	<b>2599</b> =	512,167,000.00	518,312,000.00
<b>Liabilities</b>				
	Total current liabilities	<b>3139</b> +	4,778,000.00	4,851,000.00
	Total long-term liabilities	<b>3450</b> +	301,841,000.00	305,641,000.00
	* Subordinated debt	<b>3460</b> +		
	* Amounts held in trust	<b>3470</b> +		
	<b>Total liabilities</b> (mandatory field)	<b>3499</b> =	306,619,000.00	310,492,000.00
<b>Partner's capital</b>				
	<b>Total partners' capital</b> (mandatory field)	<b>3575</b> +	205,548,000.00	207,820,000.00
	<b>Total liabilities and partners' capital</b>	<b>3585</b> =	512,167,000.00	518,312,000.00

\* Generic item

# Current Assets

## SCHEDULE 100

Form Identifier 1599

Account	Description	GIFI	Current year	Prior year
<b>Cash and deposits</b>				
	Cash .....	<b>1001</b>	9,733,000.00	4,805,000.00
	<b>Cash and deposits</b> .....		+ 9,733,000.00	4,805,000.00
<b>Accounts receivable</b>				
	* Accounts receivable .....	<b>1060</b>	3,038,000.00	3,884,000.00
	<b>Accounts receivable</b> .....		+ 3,038,000.00	3,884,000.00
<b>Other current assets</b>				
	* Other current assets .....	<b>1480</b>	1,925,000.00	3,055,000.00
	<b>Other current assets</b> .....		+ 1,925,000.00	3,055,000.00
	<b>Total current assets</b> .....	<b>1599</b>	= 14,696,000.00	11,744,000.00

\* Generic item

# Tangible Capital Assets and Accumulated Amortization

**SCHEDULE 100**

Form identifier 2008/2009

Account	Description	GIFI	Tangible capital assets	Accumulated amortization	Prior year
<b>Machinery, equipment, furniture and fixtures</b>					
	* Machinery, equipment, furniture, and fixtures . . . . .	<b>1740</b>	+ 526,448,000.00		526,448,000.00
	*Accumulated amortization of machinery, equipment, furniture, and fixtures . . . . .	<b>1741</b>		- 28,977,000.00	21,805,000.00
	<b>Total</b>		<u>526,448,000.00</u>	<u>28,977,000.00</u>	
	<b>Total tangible capital assets</b> . . . . .	<b>2008</b>	= <u>526,448,000.00</u>		<u>526,448,000.00</u>
	<b>Total accumulated amortization of tangible capital assets</b> . . . . .	<b>2009</b>		= <u>28,977,000.00</u>	<u>21,805,000.00</u>

\* Generic item

# Current Liabilities

## SCHEDULE 100

Form identifier 3139

Account	Description	GIFI	Current year	Prior year
<b>Amounts payable and accrued liabilities</b>				
	* Amounts payable and accrued liabilities	<b>2620</b>	441,000.00	216,000.00
	Interest payable	<b>2629</b>	1,072,000.00	1,029,000.00
	<b>Amounts payable and accrued liabilities</b>		<u>1,513,000.00</u>	<u>1,245,000.00</u>
<b>Due to related parties</b>				
	* Due to related parties	<b>2860</b>	1,630,000.00	3,606,000.00
	<b>Due to related parties</b>		<u>1,630,000.00</u>	<u>3,606,000.00</u>
<b>Other current liabilities</b>				
	* Other current liabilities	<b>2960</b>	1,635,000.00	
	<b>Other current liabilities</b>		<u>1,635,000.00</u>	
	<b>Total current liabilities</b>	<b>3139</b>	<u>4,778,000.00</u>	<u>4,851,000.00</u>

\* Generic item

# Long-term Liabilities

## SCHEDULE 100

Form identifier 3450

Account	Description	GIFI	Current year	Prior year
<b>Long-term debt</b>				
	* Long-term debt .....	<b>3140</b>	301,841,000.00	305,641,000.00
	<b>Long-term debt</b> .....		+ 301,841,000.00	305,641,000.00
	<b>Total long-term liabilities</b> .....	<b>3450</b>	= 301,841,000.00	305,641,000.00

\* Generic item

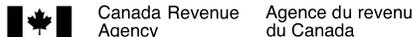
# Partner's capital

## SCHEDULE 100

GIFI Code 3575

Account	Description	GIFI	Current year	Prior year
<b>Total net income/loss</b>				
	Net income/loss	3545	19,323,000.00	16,661,000.00
	<b>Total net income/loss</b>	3550	<u>19,323,000.00</u>	<u>16,661,000.00</u>
<b>General partners' capital</b>				
	General partners' capital beginning balance	3551	136,188,000.00	135,931,000.00
	General partners' net income (loss)	3552	12,736,000.00	10,977,000.00
	General partners' drawings	3553	-14,024,000.00	-10,720,000.00
	<b>General partners' capital ending balance</b>	3560	<u>134,900,000.00</u>	<u>136,188,000.00</u>
<b>Limited partners' capital</b>				
	Limited partners' capital beginning balance	3561	71,632,000.00	71,627,000.00
	Limited partners' net income (loss)	3562	6,587,000.00	5,684,000.00
	Limited partners' drawings	3563	-7,571,000.00	-5,679,000.00
	<b>Limited partners' capital ending balance</b>	3571	<u>70,648,000.00</u>	<u>71,632,000.00</u>
	<b>Total partners' capital</b>	3575	<u>205,548,000.00</u>	<u>207,820,000.00</u>

\* Generic item



**T5013  
SCHEDULE 125**

Form identifier 125

**GENERAL INDEX OF FINANCIAL INFORMATION – GIFI**

<b>Partnership name</b> B2M LIMITED PARTNERSHIP	<b>Partnership account number</b> 80820 9530 RZ0001	<b>Fiscal period end</b> Year Month Day 2018-12-31	Original <input checked="" type="checkbox"/> Amended <input type="checkbox"/>
--	--	--	--

**Income statement information**

<b>Description</b>	<b>GIFI</b>
--------------------	-------------

Is this a NIL schedule? . . . . . **999**  Yes  No

Operating name . . . . . **0001**  
 Description of the operation . . . . . **0002** ELECTRICITY TRANSMISSION  
 Sequence Number . . . . . **0003** 01

Account	Description	GIFI	Current year	Prior year
---------	-------------	------	--------------	------------

**Income statement information**

Total sales of goods and services		<b>8089</b> +	33,173,000.00	30,423,000.00
Cost of sales		<b>8518</b> -		
<b>Gross profit/loss</b>		<b>8519</b> =	33,173,000.00	30,423,000.00
Cost of sales		<b>8518</b> +		
Total operating expenses		<b>9367</b> +	13,850,000.00	13,762,000.00
<b>Total expenses</b> (mandatory field)		<b>9368</b> =	13,850,000.00	13,762,000.00
Total revenue (mandatory field)		<b>8299</b> +	33,173,000.00	30,423,000.00
Total expenses (mandatory field)		<b>9368</b> -	13,850,000.00	13,762,000.00
<b>Net non-farming income</b>		<b>9369</b> =	19,323,000.00	16,661,000.00

**Farming income statement information**

Total farm revenue (mandatory field)		<b>9659</b> +		
Total farm expenses (mandatory field)		<b>9898</b> -		
<b>Net farm income</b>		<b>9899</b> =		

<b>Net income/loss before extraordinary items – all operations</b>		<b>9970</b> =	19,323,000.00	16,661,000.00
--	--	---------------	---------------	---------------

<b>Total other comprehensive income</b>		<b>9998</b> =		
---	--	---------------	--	--

**Extraordinary items and income (linked to Schedule 140)**

Extraordinary item(s)		<b>9975</b> -		
Legal settlements		<b>9976</b> -		
Unrealized gains/losses		<b>9980</b> +		
Unusual items		<b>9985</b> -		
Current income taxes		<b>9990</b> -		
Deferred income tax provision		<b>9995</b> -		
Total – Other comprehensive income		<b>9998</b> +		
<b>Net income/loss after taxes and extraordinary items</b> (mandatory field)		<b>9999</b> =	19,323,000.00	16,661,000.00

# Revenue

## SCHEDULE 125

Form identifier 8299

Account	Description	GIFI	Current year	Prior year
	* Sales of goods and services to related parties	<b>8020</b> +	33,173,000.00	30,423,000.00
	<b>Total sales of goods and services</b>	<b>8089</b> =	33,173,000.00	30,423,000.00
	<b>Total revenue</b>	<b>8299</b> =	<u>33,173,000.00</u>	<u>30,423,000.00</u>

\* Generic item

# Operating Expenses

## SCHEDULE 125

Form identifier 9367

Account	Description	GIFI	Current year	Prior year
	* Amortization of tangible assets	8670	7,172,000.00	7,172,000.00
<b>Interest and bank charges</b>				
	* Interest and bank charges	8710	5,271,000.00	5,265,000.00
	<b>Interest and bank charges</b>		<u>5,271,000.00</u>	<u>5,265,000.00</u>
<b>Other expenses</b>				
	General and administrative expenses	9284	1,407,000.00	1,325,000.00
	<b>Other expenses</b>		<u>1,407,000.00</u>	<u>1,325,000.00</u>
	<b>Total operating expenses</b>	<b>9367</b>	<u>13,850,000.00</u>	<u>13,762,000.00</u>

\* Generic item

# Financial Statement Notes Checklist

Protected B when completed

**T5013**  
**Schedule 141**

<b>Partnership name</b> B2M LIMITED PARTNERSHIP	<b>Partnership account number</b> 80820 9530 RZ0001	<b>Fiscal period end</b> Year Month Day 2018-12-31	<input checked="" type="checkbox"/> Original <input type="checkbox"/> Amended
--	--	--	--

- Fill out this schedule from the perspective of the person (referred to in this schedule as the "accountant") who prepared or reported on the financial statements.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- For more information, see Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*, and Guide RC4088, *General Index of Financial Information (GIFI)*.
- Attach the original copy of this completed schedule, along with any "Notes to the financial statements" and the auditor's or accountant's report, to Form T5013 FIN, *Partnership Financial Return*.

## Part 1 – Information on the accountant who prepared or reported on the financial statements

Does the accountant have a professional designation? **095** 1 Yes  2 No

Is the accountant connected with the partnership? \* **097** 1 Yes  2 No

**Note:** If the accountant does not have a professional designation or is connected with the partnership, you do not have to complete parts 2 and 3 below.  
\* A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

## Part 2 – Type of involvement with the financial statements

Choose the option that represents the accountant's highest level of involvement: **198**

Completed an auditor's report 1

Completed a review engagement report 2

Conducted a compilation engagement 3

## Part 3 – Reservations

If you selected option 1 or option 2 in part 2 above, answer the following question:

Has the accountant expressed a reservation? **099** 1 Yes  2 No

## Part 4 – Other information (continued on page 2)

If you have a professional designation and are not the accountant associated with the financial statements in part 1 above, choose one of the following options: **110**

Prepared the information return (financial statements prepared by client) 1

Prepared the information return and the financial information contained therein (financial statements have not been prepared) 2

Were notes to the financial statements prepared? **101** 1 Yes  2 No

If **yes**, answer the following four questions:

Are subsequent events mentioned in the notes? **104** 1 Yes  2 No

Is re-evaluation of asset information mentioned in the notes? **105** 1 Yes  2 No

Is contingent liability information mentioned in the notes? **106** 1 Yes  2 No

Is information regarding commitments mentioned in the notes? **107** 1 Yes  2 No

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below **108** 1 Yes  2 No

Are you filing joint venture(s) financial statements? **109** 1 Yes  2 No

<b>Partnership account number</b> 80820 9530 RZ0001	<b>Fiscal period end</b> Year Month Day 2018-12-31
--	--

Protected B when completed

**Part 4 – Other information (continued)**

**Impairment and fair value changes**

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? . . . . .

**200** 1 Yes  2 No

If **yes**, enter the amount recognized:

	<b>In net income</b>	<b>In other comprehensive</b>
	Increase (decrease)	income
	Increase (decrease)	Increase (decrease)
Property, plant and equipment . . . . .	<b>210</b> _____	<b>211</b> _____
Intangible assets . . . . .	<b>215</b> _____	<b>216</b> _____
Investment property . . . . .	<b>220</b> _____	
Biological assets . . . . .	<b>225</b> _____	
Financial instruments . . . . .	<b>230</b> _____	<b>231</b> _____
Other . . . . .	<b>235</b> _____	<b>236</b> _____

**Financial instruments**

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)? . . . . .

**250** 1 Yes  2 No

Did the partnership apply hedge accounting during the fiscal period? . . . . .

**255** 1 Yes  2 No

Did the partnership discontinue hedge accounting during the fiscal period? . . . . .

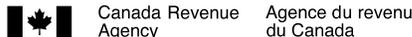
**260** 1 Yes  2 No

**Adjustments to opening partners' capital**

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? . . . . .

**265** 1 Yes  2 No

If **yes**, you have to maintain a separate reconciliation.



# Net Income (Loss) for Income Tax Purposes

Protected B when completed

**T5013**  
**Schedule 1**

<b>Partnership name</b> B2M LIMITED PARTNERSHIP	<b>Partnership account number</b> 80820 9530 RZ0001	<b>Fiscal period end</b> Year Month Day 2018-12-31	<input checked="" type="checkbox"/> Original <input type="checkbox"/> Amended
--	--	--	--

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 forms).
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to Form T5013 FIN, Partnership Financial Return.

Is this a NIL schedule?  Yes  No **999**

(If **yes**, do not use zeroes (000 00), dashes ( - ), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140	<b>500</b>	19,323,000.00
<b>Add:</b>		
Provision for Part IX.1 specified investment flow through (SIFT) taxes	<b>101</b>	
Amortization/depreciation of tangible assets	<b>104</b>	7,172,000.00
Amortization of natural resource assets	<b>105</b>	
Amortization of intangible assets	<b>106</b>	
Recapture of capital cost allowance from Schedule 8	<b>107</b>	
Income or loss for tax purposes from partnerships	<b>109</b>	
Loss in equity of affiliates	<b>110</b>	
Loss on disposal of assets per financial statements	<b>111</b>	
Charitable donations and gifts from Schedule 2	<b>112</b>	
Political contributions from Schedule 2	<b>114</b>	
Current fiscal period's holdbacks	<b>115</b>	
Deferred and prepaid expenses	<b>116</b>	
Depreciation in inventory – end of fiscal period	<b>117</b>	
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	<b>118</b>	
Capitalized interest and property taxes on vacant land	<b>119</b>	
Non-deductible club dues and fees	<b>120</b>	
Non-deductible meals and entertainment expenses	<b>121</b>	
Non-deductible automobile expenses	<b>122</b>	
Non-deductible life insurance premiums	<b>123</b>	
Non-deductible company pension plans	<b>124</b>	
Reserves from financial statements – balance at the end of the fiscal period	<b>126</b>	
Soft costs on construction and renovation of buildings	<b>127</b>	
Salaries and wages paid to partners deducted on financial statements	<b>150</b>	
Cost of products available for sale that were consumed	<b>151</b>	
Personal expenses of the partners paid by the partnership	<b>152</b>	
Dividend rental arrangement compensation payment deductions	<b>154</b>	
Renounced exploration, development and resource property expenses deducted per financial statements from Schedule 52	<b>155</b>	
Certain fines and penalties	<b>156</b>	
Amount from line 508 on page 2 of this schedule	<b>199</b>	4,690,197.00
<b>Total (Add lines 101 to 199. Enter this amount on line 501)</b>		<b>501</b> + 11,862,197.00
<b>Deduct:</b> Amount from line 511 on page 3 of this schedule		<b>502</b> - 22,767,522.95
<b>Net income (loss) for income tax purposes – (line 500 plus line 501 minus line 502)</b>		<b>503</b> = 8,417,674.05
<b>Deduct:</b> Net income (loss) for general partners		<b>504</b> -
<b>Net income (loss) for income tax purposes for limited and non-active partners (line 503 minus line 504)</b>		<b>505</b> = 8,417,674.05

**Partnership account number**  
80820 9530 RZ0001

**Fiscal period end**  
Year Month Day  
2018-12-31

**Protected B** when completed

**Add:**

Accounts payable and accruals for cash basis – closing	201	_____
Accounts receivable and prepaid for cash basis – opening	202	_____
Accrual inventory – opening	203	_____
Accrued dividends – prior fiscal period	204	_____
Book loss on joint ventures or partnerships	205	_____
Capital items expensed	206	_____
Debt issue expense	208	_____
Deemed dividend income	209	_____
Deemed interest on loans to non-residents	210	_____
Deemed interest received	211	_____
Development expenses claimed in current fiscal period	212	_____
Dividend stop-loss adjustment	213	_____
Dividends credited to the investment account	214	_____
Exploration expenses claimed in current fiscal period	215	_____
Financing fees deducted in books	216	_____
Foreign accrual property income	217	_____
Foreign affiliate property income	218	_____
Foreign exchange included in retained earnings	219	_____
Gain on settlement of debt – income inclusion under subsection 80(13)	220	_____
Interest paid on income debentures	221	_____
Limited partnership losses	222	_____
Loss from international banking centres	223	_____
Mandatory inventory adjustment – included in current fiscal period	224	_____
Non-deductible advertising	226	_____
Non-deductible interest	227	_____
Non-deductible legal and accounting fees	228	_____
Optional value of inventory – included in current fiscal period	229	_____
Other expenses from financial statements	230	_____
Recapture of SR&ED expenditures from Form T661	231	_____
Resource amounts deducted	232	_____
Sales tax assessments	234	_____
Write-down of capital property	236	_____
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	_____
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	238	_____
Taxable/Non-deductible other comprehensive income items	239	_____

**Total (Add lines 201 to 239. Enter this amount on line 506)** **506** + \_\_\_\_\_

**Other additions:**

<b>600</b> _____	<b>290</b> _____
<b>601</b> Regulatory Asset	<b>291</b> 4,690,197.00
<b>602</b> _____	<b>292</b> _____
<b>603</b> _____	<b>293</b> _____
<b>604</b> _____	<b>294</b> _____

**Total (Add lines 290 to 294. Enter this amount on line 507)** **507** + 4,690,197.00

**Total (Add lines 506 and 507)** **508** = 4,690,197.00

Enter the amount from line 508 on line 199 on page 1 of this schedule.

**Partnership account number**  
80820 9530 RZ0001

**Fiscal period end**  
Year Month Day  
2018-12-31

**Protected B** when completed

**Deduct:**

Accounts payable and accruals for cash basis – opening	300	_____
Accounts receivable and prepaid for cash basis – closing	301	_____
Accrual inventory – closing	302	_____
Accrued dividends – current fiscal period	303	_____
Bad debt	304	_____
Book income of joint venture or partnership	305	_____
Equity in income from affiliates	306	_____
Exempt income under section 81	307	_____
Income from international banking centres	308	_____
Mandatory inventory adjustment – included in prior fiscal period	309	_____
Contributions to a qualifying environmental trust	310	_____
Non-Canadian advertising expenses – broadcasting	311	_____
Non-Canadian advertising expenses – printed materials	312	_____
Optional value of inventory – included in prior fiscal period	313	_____
Other income from financial statements	314	_____
Payments made for allocations in proportion to borrowing and bonus interest payments	315	_____
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316	_____
Non-taxable/Deductible other comprehensive income items	347	_____

**Other less common deductions:**

<b>700</b> 2014 deferred financing fees - 20(1)(e)	<b>390</b>	24,962.00
<b>701</b> 2015 deferred financing fees - 20(1)(e)	<b>391</b>	15,132.00
<b>702</b> _____	<b>392</b>	_____
<b>703</b> _____	<b>393</b>	_____
<b>704</b> _____	<b>394</b>	_____

**Total (Add lines 300 to 394. Enter this amount on line 509)** 40,094.00 ► **509** + 40,094.00

**Other deductions:**

Gain on disposal of assets per financial statements	401	_____
Non-taxable dividends under section 83	402	_____
Capital cost allowance from Schedule 8	403	22,727,428.95
Terminal loss from Schedule 8	404	_____
Foreign non-business tax deduction under subsection 20(12)	407	_____
Prior fiscal period's holdbacks	408	_____
Deferred and prepaid expenses	409	_____
Depreciation in inventory – end of prior fiscal period	410	_____
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411	_____
Reserves from financial statements – balance at the beginning of the fiscal period	414	_____
Patronage dividends	416	_____
Contributions to deferred income plans	417	_____

**Total (Add lines 401 to 417. Enter this amount on line 510)** 22,727,428.95 ► **510** + 22,727,428.95

**Total (Add lines 509 and 510)** ..... **511** = 22,767,522.95  
Enter this amount on line 502 on page 1 of this schedule.

### Capital Cost Allowance (CCA)

Protected B when completed

**T5013**  
**Schedule 8**

<b>Partnership name</b> B2M LIMITED PARTNERSHIP	<b>Partnership account number</b> 80820 9530 RZ0001	<b>Fiscal period end</b> Year Month Day 2018-12-31	<input checked="" type="checkbox"/> Original <input type="checkbox"/> Amended
--	--	--	--

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period, and to account for acquisitions and/or dispositions of depreciable property.
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 8.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

200	201	203	205	207		211		212	213	215	217	220
(1) Class number	(2) Undepreciated capital cost (UCC) at the beginning of the fiscal period (UCC at the end of the previous fiscal period (column (13) of Schedule 8))	(3) Cost of acquisitions during the fiscal period (new property must be available for use) *	(4) Net adjustments (show negative amounts in brackets) **	(5) Proceeds of dispositions during the fiscal period (amount not to exceed the capital cost)	(6) UCC (column (2) plus column (3) plus or minus column (4) minus column (5))	(7) 50% rule (1/2 of the amount, if any, by which the net cost of acquisitions exceeds column (5)) ***	(8) Reduced UCC (column (6) minus column (7))	(9) CCA rate (%)	(10) Recapture of CCA	(11) Terminal loss	(12) CCA (column (8) multiplied by column (9), or a lower amount) ****	(13) UCC at the end of the fiscal period (column (6) minus column (12))
1	2,825,080.60				2,825,080.60		2,825,080.60	4.00			113,003.22	2,712,077.38
2	234,845,161.01				234,845,161.01		234,845,161.01	8.00			18,787,612.88	216,057,548.13
3	54,668,754.93				54,668,754.93		54,668,754.93	5.00			3,826,812.85	50,841,942.08
4												
5												
6												
7												
8												
9												
10												
	292,338,996.54				292,338,996.54		292,338,996.54		<b>230</b>	<b>240</b>	<b>250</b>	269,611,567.59
<b>Totals</b>											22,727,428.95	

\* Include any property acquired in previous fiscal periods that has now become available for use. This property would have been previously excluded from column (3). List separately any acquisitions that are not subject to the 50% rule; see the *Income Tax Regulations* 1100(2) and (2.2).

\*\* Include amounts applicable to depreciable assets transferred under section 85. See Guide T4068 for examples of adjustments to include in column (4).

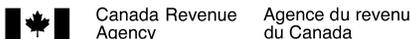
\*\*\* The net cost of acquisitions is the cost of acquisitions column (3) plus or minus certain adjustments from column (4). For exceptions to the 50% rule, see Interpretation Bulletin IT-285, *Capital Cost Allowance – General Comments*.

\*\*\*\* If the fiscal period is shorter than 365 days, prorate the CCA claim except for some classes. For more information, see Guide T4068.

Enter the amount on line 230 on line 107 of Schedule 1.  
Enter the amount on line 240 on line 404 of Schedule 1.  
Enter the amount on line 250 on line 403 of Schedule 1.

See the privacy notice on your return.

Approval code: RC-18-P006



### Partner's Ownership and Account Activity

Protected B when completed

**T5013**  
**Schedule 50**

<b>Partnership name</b> B2M LIMITED PARTNERSHIP	<b>Partnership account number</b> 808209530RZ0001	<b>Fiscal period end</b> Year Month Day 2018-12-31	<input checked="" type="checkbox"/> Original <input type="checkbox"/> Amended
--	--	--	--

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

<b>Number of partners</b>	<b>010</b>	3
<b>Number of partners who disposed of all, or part of, their partnership interest</b>	<b>011</b>	
<b>Number of nominees or agents</b>	<b>012</b>	1
<b>Total of all amounts from line 220</b>	<b>015</b>	8,417,674.00

Partner 1	Ownership					Fiscal period's income (loss) allocation	Account activity
<b>100</b>	<b>101</b>	<b>105</b>	<b>106</b>	<b>107</b>	<b>110</b>	<b>220</b>	<b>300</b>
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.	818381840RC0001	2	2	65.7086	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	5,570,225.00	250017271.00
<b>Account activity (continued)</b>					<b>At-risk amount (ARA) (for limited partners only)</b>		
<b>310</b>	<b>320</b>	<b>330</b>	<b>340</b>	<b>350</b>	<b>410</b>	<b>420</b>	<b>430</b>
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-20,246.00		-14,024,454.00				

Partner 2	Ownership					Fiscal period's income (loss) allocation	Account activity
<b>100</b>	<b>101</b>	<b>105</b>	<b>106</b>	<b>107</b>	<b>110</b>	<b>220</b>	<b>300</b>
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
HYDRO ONE B2M LP INC	818382046RC0001	2	0	0.1000	<input type="checkbox"/> Yes <input checked="" type="checkbox"/> No	8,477.00	375590.00
<b>Account activity (continued)</b>					<b>At-risk amount (ARA) (for limited partners only)</b>		
<b>310</b>	<b>320</b>	<b>330</b>	<b>340</b>	<b>350</b>	<b>410</b>	<b>420</b>	<b>430</b>
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-31.00		-21,867.00		8,477.00		

Approval code: RC-18-P006

Protected B when completed

Partner 3		Ownership					Fiscal period's income (loss) allocation	Account activity
100		101	105	106	107	110	220	300
Partner name		Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base
SON FINANCE CORP (TRUSTEE)								

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable
	-55,304.00		-7,549,229.00				

Partner 4		Ownership					Fiscal period's income (loss) allocation	Account activity
100		101	105	106	107	110	220	300
Partner name		Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 5		Ownership					Fiscal period's income (loss) allocation	Account activity
100		101	105	106	107	110	220	300
Partner name		Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?	Partner's share of the net income (loss)	Cost base

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

Filer's name and address – Nom et adresse du déclarant  
**B2M LIMITED PARTNERSHIP**  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
<b>002</b> 2	<b>003</b> CAN	<b>004</b> 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

**001** 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

**010**

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

**020** 5,570,225 00

Partner's identification number  
 Numéro d'identification de l'associé

**006** 818381840RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

**005** 65.708615

Total capital gains (losses)  
 Total des gains (pertes) en capital

**030**

Capital cost allowance  
 Déduction pour amortissement

**040** 14,979,854 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

▶ **HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.**

185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
113		14,024,454 00	116		5,570,225 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		21,864,624 00			

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Filer's name and address – Nom et adresse du déclarant  
**B2M LIMITED PARTNERSHIP**  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
<b>002</b> 0	<b>003</b> CAN	<b>004</b> 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

**001** 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

**010** 8,477 00

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

**020**

Partner's identification number  
 Numéro d'identification de l'associé

**006** 818382046RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

**005** 0.100000

Total capital gains (losses)  
 Total des gains (pertes) en capital

**030**

Capital cost allowance  
 Déduction pour amortissement

**040** 22,797 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées)      First name – Prénom      Initials – Initiales

▶ **HYDRO ONE B2M LP INC**

483 BAY STREET  
 7TH FLOOR SOUTH TOWER  
 TORONTO ON M5G2P5

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		8,477 00	113		21,867 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		33,275 00			

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Filer's name and address – Nom et adresse du déclarant  
**B2M LIMITED PARTNERSHIP**  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
<b>002</b> 4	<b>003</b> CAN	<b>004</b> 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

**001** 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

**010** 2,838,972.00

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

**020**

Partner's identification number  
 Numéro d'identification de l'associé

**006** 822177333RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

**005** 34.191385

Total capital gains (losses)  
 Total des gains (pertes) en capital

**030**

Capital cost allowance  
 Déduction pour amortissement

**040** 7,724,778.00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées)      First name – Prénom      Initials – Initiales

▶ **SON FINANCE CORP (TRUSTEE)**

**BDO CANADA**  
 663 BERFORD STREET P.O. BOX 849  
 WIARTON ON N0H2T0

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		2,838,972.00	113		7,549,229.00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		11,275,101.00			

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
<input type="text"/>					

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*) / Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002 2	003 CAN	004 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)  
 001 808209530RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire  
 010

Total business income (loss) / Total du revenu (de la perte) d'entreprise  
 020 5,570,225 00

Partner's identification number / Numéro d'identification de l'associé  
 006 818381840RC0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes  
 005 65.708615

Total capital gains (losses) / Total des gains (pertes) en capital  
 030

Capital cost allowance / Déduction pour amortissement  
 040 14,979,854 00

**Partner's name and address – Nom et adresse de l'associé**  
 Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales  
 HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
113		14,024,454 00	116		5,570,225 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		21,864,624 00			

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

See the privacy notice on your return / Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Attach to your income tax return 2**  
**Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2**

See recipient instructions / Voir les instructions du bénéficiaire

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 2	003 CAN	004 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

001 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

010

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

020 5,570,225 00

Partner's identification number  
 Numéro d'identification de l'associé

006 818381840RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

005 65.708615

Total capital gains (losses)  
 Total des gains (pertes) en capital

030

Capital cost allowance  
 Déduction pour amortissement

040 14,979,854 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

▶ HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
113		14,024,454 00	116		5,570,225 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		21,864,624 00			

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

See the privacy notice on your return / Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Keep this slip for your records 3**  
**Bénéficiaire – Conservez pour vos dossiers 3**

See recipient instructions / Voir les instructions du bénéficiaire

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'énoncé au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 0	003 CAN	004 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

001 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

010 8,477 00

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

020

Partner's identification number  
 Numéro d'identification de l'associé

006 818382046RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

005 0.100000

Total capital gains (losses)  
 Total des gains (pertes) en capital

030

Capital cost allowance  
 Déduction pour amortissement

040 22,797 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

HYDRO ONE B2M LP INC  
 483 BAY STREET  
 7TH FLOOR SOUTH TOWER  
 TORONTO ON M5G2P5

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		8,477 00	113		21,867 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		33,275 00			

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

See the privacy notice on your return / Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Attach to your income tax return 2**  
**Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2**

See recipient instructions / Voir les instructions du bénéficiaire

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*) / Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002 0	003 CAN	004 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)  
 001 808209530RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire  
 010 8,477 00

Total business income (loss) / Total du revenu (de la perte) d'entreprise  
 020

Partner's identification number / Numéro d'identification de l'associé  
 006 818382046RC0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes  
 005 0.100000

Total capital gains (losses) / Total des gains (pertes) en capital  
 030

Capital cost allowance / Déduction pour amortissement  
 040 22,797 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales  
 HYDRO ONE B2M LP INC  
 483 BAY STREET  
 7TH FLOOR SOUTH TOWER  
 TORONTO ON M5G2P5

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		8,477 00	113		21,867 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		33,275 00			

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case Code Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

See the privacy notice on your return / Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Keep this slip for your records 3**  
**Bénéficiaire – Conservez pour vos dossiers 3**

See recipient instructions / Voir les instructions du bénéficiaire

Filer's name and address – Nom et adresse du déclarant  
**B2M LIMITED PARTNERSHIP**  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*) / Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
<b>002</b> 4	<b>003</b> CAN	<b>004</b> 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)  
**001** 808209530RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire  
**010** 2,838,972.00

Total business income (loss) / Total du revenu (de la perte) d'entreprise  
**020**

Partner's identification number / Numéro d'identification de l'associé  
**006** 822177333RC0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes  
**005** 34.191385

Total capital gains (losses) / Total des gains (pertes) en capital  
**030**

Capital cost allowance / Déduction pour amortissement  
**040** 7,724,778.00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées)      First name – Prénom      Initials – Initiales

▶ **SON FINANCE CORP (TRUSTEE)**

**BDO CANADA**  
 663 BERFORD STREET P.O. BOX 849  
 WIARTON ON N0H2T0

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		2,838,972.00	113		7,549,229.00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		11,275,101.00			

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

See the privacy notice on your return / Consultez l'avis de confidentialité dans votre déclaration

**For Recipient – Attach to your income tax return 2**  
**Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2**

See recipient instructions / Voir les instructions du bénéficiaire

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see statement on reverse side \*) / Numéro d'inscription de l'abri fiscal (lisez l'énoncé au dos \*)

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)  
 001 808209530RZ0001

Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire  
 010 2,838,972.00

Total business income (loss) / Total du revenu (de la perte) d'entreprise  
 020

Partner's identification number / Numéro d'identification de l'associé  
 006 822177333RC0001

Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes  
 005 34.191385

Total capital gains (losses) / Total des gains (pertes) en capital  
 030

Capital cost allowance / Déduction pour amortissement  
 040 7,724,778.00

**Partner's name and address – Nom et adresse de l'associé**  
 Last name (print) – Nom de famille (en lettres moulées) / First name – Prénom / Initials – Initiales  
 SON FINANCE CORP (TRUSTEE)  
 BDO CANADA  
 663 BERFORD STREET P.O. BOX 849  
 WIARTON ON N0H2T0

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		2,838,972.00	113		7,549,229.00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		11,275,101.00			

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box – Case Code Other information – Autres renseignements

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

Box Case Code Amount – Montant / Box Case Code Amount – Montant

See the privacy notice on your return / Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Keep this slip for your records 3 / Bénéficiaire – Conservez pour vos dossiers 3

See recipient instructions / Voir les instructions du bénéficiaire

Filer's name and address – Nom et adresse du déclarant  
**B2M LIMITED PARTNERSHIP**  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
<b>002</b> 2	<b>003</b> CAN	<b>004</b> 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

**001** 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

**010** [ ] [ ]

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

**020** 5,570,225 00

Partner's identification number  
 Numéro d'identification de l'associé

**006** 818381840RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

**005** 65.708615

Total capital gains (losses)  
 Total des gains (pertes) en capital

**030** [ ] [ ]

Capital cost allowance  
 Déduction pour amortissement

**040** 14,979,854 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées) First name – Prénom Initials – Initiales

▶ **HYDRO ONE INDIGENOUS PARTNERSHIPS GP INC.**

185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
113	[ ]	14,024,454 00	116	[ ]	5,570,225 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118	[ ]	21,864,624 00	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Box – Case Code Other information – Autres renseignements

[ ] [ ] [ ]

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
[ ]	[ ]	[ ] [ ]	[ ]	[ ]	[ ] [ ]

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 0	003 CAN	004 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)  
 001 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire  
 010 8,477 00

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise  
 020

Partner's identification number  
 Numéro d'identification de l'associé  
 006 818382046RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes  
 005 0.100000

Total capital gains (losses)  
 Total des gains (pertes) en capital  
 030

Capital cost allowance  
 Déduction pour amortissement  
 040 22,797 00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées)      First name – Prénom      Initials – Initiales

HYDRO ONE B2M LP INC  
 483 BAY STREET  
 7TH FLOOR SOUTH TOWER  
 TORONTO ON M5G2P5

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		8,477 00	113		21,867 00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		33,275 00			

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Filer's name and address – Nom et adresse du déclarant  
 B2M LIMITED PARTNERSHIP  
 185 CLEGG ROAD  
 MARKHAM ON L6G1B7

Tax shelter identification number (see **statement** on reverse side \*)  
 Numéro d'inscription de l'abri fiscal (lisez l'**énoncé** au dos \*)

Partner code Code de l'associé	Country code Code du pays	Recipient type Genre de bénéficiaire
002 4	003 CAN	004 3

Partnership account number (15 characters)  
 Numéro de compte de la société de personnes (15 caractères)

001 808209530RZ0001

Total limited partner's business income (loss)  
 Total du revenu (de la perte) d'entreprise du commanditaire

010 2,838,972.00

Total business income (loss)  
 Total du revenu (de la perte) d'entreprise

020

Partner's identification number  
 Numéro d'identification de l'associé

006 822177333RC0001

Partner's share (%) of partnership  
 Part de l'associé (%) dans la société de personnes

005 34.191385

Total capital gains (losses)  
 Total des gains (pertes) en capital

030

Capital cost allowance  
 Déduction pour amortissement

040 7,724,778.00

**Partner's name and address – Nom et adresse de l'associé**

Last name (print) – Nom de famille (en lettres moulées)      First name – Prénom      Initials – Initiales

▶ SON FINANCE CORP (TRUSTEE)

BDO CANADA  
 663 BERFORD STREET P.O. BOX 849  
 WIARTON ON N0H2T0

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
104		2,838,972.00	113		7,549,229.00

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
118		11,275,101.00			

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

Box – Case      Code      Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

# Summary of Partnership Income / Sommaire des revenus d'une société de personnes

**T5013** Summary / Sommaire

Fill out this summary and related slips using the instructions in guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.

Remplissez ce sommaire et les feuillets connexes en suivant les instructions du guide T4068, *Guide pour la déclaration de renseignements des sociétés de personnes (formulaires T5013)*.

Do not use this area. N'inscrivez rien ici.

For the fiscal period – Pour l'exercice

Start / Début: 2018-01-01 (Year: 2018, Month: 01, Day: 01)  
End / Fin: 2018-12-31 (Year: 2018, Month: 12, Day: 31)

Partnership's account number

Noméro de compte de la société de personnes: 80820 9530 RZ0001

Postal or ZIP code / Code postal ou ZIP

50 [ ] [ ] [ ] [ ] [ ] [ ] 1616

Name of the partnership – Nom de la société de personnes

B2M LIMITED PARTNERSHIP / L6G1B7

Are you a nominee or agent? (tick if yes and provide the following information)

Êtes-vous un mandataire ou un agent? (cochez si oui et fournir les renseignements qui suivent)

Name of the nominee or agent – Nom du mandataire ou de l'agent

Postal or ZIP code / Code postal ou ZIP

Nominee or agent's account number

Noméro de compte du mandataire ou de l'agent: [ ] [ ] [ ] [ ] [ ] [ ]

Is the partnership a tax shelter? (tick if yes)

La société de personnes est-elle un abri fiscal? (cochez si oui)

If yes, provide the tax shelter identification number

Si oui, fournir le numéro d'identification de l'abri fiscal: [ ] [ ] [ ] [ ] [ ] [ ]

## Totals from T5013 slips – Totaux des feuillets T5013

Total number of T5013 information slips attached: / Nombre total de feuillets de renseignements T5013 joints: 009 3

Total limited partner's business income (loss) – Total du revenu (de la perte) d'entreprise du commanditaire	010	2,847,449	00
Total business income (loss) – Total du revenu (de la perte) d'entreprise	020	5,570,225	00
Total capital gains (losses) – Total des gains (pertes) en capital	030		
Capital cost allowance – Déduction pour amortissement	040	22,727,429	00

Complete the six generic boxes identified below taken from the T5013 slips – Remplissez les lignes ci-dessous pour les six cases génériques qui parviennent des feuillets T5013

Canadian and foreign net rental income (loss) – Revenu net (perte nette) de location canadien et étranger	110		
Professional income (loss) – Revenu (perte) de profession libérale	120		
Renounced Canadian exploration expenses – Frais renoncés d'exploration au Canada	190		
Renounced Canadian development expenses – Frais renoncés d'aménagement au Canada	191		
Expenses qualifying for an ITC – Frais admissibles aux fins du CII	194		
Total carrying charges – Total des frais financiers	210		

Person to contact about this return / Personne-ressource que nous pouvons contacter à propos de cette déclaration

076 Tran, Nancy / 078 (416) 345-6778

### Certification – Attestation

I certify that the information given in this return and related summary and slips is correct and complete. / J'atteste que les renseignements fournis dans cette déclaration de renseignements et sur tous les feuillets connexes sont exacts et complets.

2019-03-29

Date

Signature of authorized person – Signature d'une personne autorisée

VP CORPORATE TAX

Position or office – Poste ou titre

Prepared by – Préparé par

Date: 2019-03-29

Personal information, including the social insurance number, is collected under the *Income Tax Act* to administer tax, benefits, and related programs. It may also be used for any purpose related to the administration or enforcement of the Act such as audit, compliance and the payment of debts owed to the Crown. It may be shared or verified with other federal, provincial/territorial government institutions to the extent authorized by law. Failure to provide this information may result in interest payable, penalties or other actions. Under the *Privacy Act*, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source [www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html](http://www.cra-arc.gc.ca/gncy/tp/nfsrc/nfsrc-eng.html), personal information bank(s) CRA PPU 224.

Les renseignements personnels sont recueillis selon la *Loi de l'impôt sur le revenu* afin d'administrer les programmes fiscaux, de prestations et autres. Ils peuvent également être utilisés pour toute fin liée à l'application ou à l'exécution de la *Loi* telle que la vérification, l'observation et le recouvrement des sommes dues à l'État. Les renseignements peuvent être transmis à une autre institution gouvernementale fédérale, provinciale ou territoriale, ou vérifiés auprès de celles-ci, dans la mesure où la loi l'autorise. Cependant, le défaut de fournir ces renseignements pourrait entraîner des intérêts à payer, des pénalités ou d'autres mesures. Les particuliers ont le droit, selon la *Loi sur la protection des renseignements personnels*, d'accéder à leurs renseignements personnels et de demander une modification, s'il y a des erreurs ou omissions. Consultez Info Source en allant à [www.arc.gc.ca/gncy/tp/nfsrc/nfsrc-fra.html](http://www.arc.gc.ca/gncy/tp/nfsrc/nfsrc-fra.html) et le(s) Fichier(s) de renseignements personnels ARC PPU 224.

**Z-FACTOR CLAIMS**

1  
2  
3  
4

Hydro One is not seeking recovery of any material costs associated with unforeseen events as described in section 2.8.12 of the Filing Requirements.



1 **2. CAPITAL STRUCTURE**

2  
3 B2M LP's deemed capital structure for rate-making purposes is 60% debt and 40%  
4 common equity of utility rate base, as affirmed by the OEB's Decision in B2M LP's 2015  
5 to 2019 transmission rate application (EB-2015-0026). The 60% debt component is  
6 comprised of 4% deemed short-term debt and 56% long-term debt.

7  
8 This structure is consistent with the OEB's report on the Cost of Capital for Ontario's  
9 Regulated Utilities, dated December 11, 2009 (EB-2009-0084), and its subsequent  
10 Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated  
11 Utilities, dated January 14, 2016.

12  
13 **2.1 COST OF CAPITAL SUMMARY**

14  
15 The cost of capital as described in this Exhibit has been reflected in the revenue  
16 requirement for the Application's Test Year. B2M LP's proposed 2020 cost of capital is  
17 presented in Table 1:

18  
19 **Table 1 - 2020 Cost of Capital**

<b>2020</b>				
<b>Amount of Deemed Return</b>	<b>(\$M)</b>	<b>%</b>	<b>Cost Rate (%)</b>	<b>Return (\$M)</b>
Long-term debt	274.3	56%	3.08%	8.4
Short-term debt	19.6	4%	2.82%	0.6
Common equity	196.0	60%	8.98%	17.6
<b>Total</b>	<b>489.9</b>	<b>100%</b>	<b>5.43%</b>	<b>26.6</b>

20  
21 When the OEB releases its 2020 cost of capital parameters, B2M LP will update the  
22 revenue requirement for the 2020 Test Year to reflect: (a) the OEB-approved 2020 return  
23 on equity and short-term debt rates; and (b) a long-term debt rate based on B2M LP's  
24 weighted average of its existing debt rate and the rate on B2M LP's forecast debt

Witness: Samir Chhelavda

1 refinancing in 2020, using the September 2019 Consensus Forecast. B2M LP proposes  
2 that the 2020 cost of capital parameters established at that time be used to determine the  
3 final revenue requirements for the 2020 Test Year.

4  
5 The historical, Bridge and Test year debt and equity summary schedules are provided at  
6 Exhibit G, Tab 1, Schedule 3.

7  
8 The OEB is expected to issue its Decision and Order before B2M LP issues new debt to  
9 refinance its maturing long-term debt in 2020. The future refinancing rate on 100% of  
10 B2M LP's long-term debt is unknown and could therefore have a material impact on  
11 B2M LP's financial performance if the actual cost is not reflected in rates. B2M LP  
12 proposes a one-time update to the cost of long-term debt, at the first annual update for  
13 rates in 2021, to reflect the actual market rate achieved on the long-term debt it will issue.  
14 In the alternative, if approval to update the long-term debt at the first annual update for  
15 rates in 2021 is not granted, B2M LP proposes to apply the forecast new long-term debt  
16 rate of 3.63%<sup>1</sup> beginning in 2020, to determine the cost of debt during the five-year  
17 period.

### 18 19 **3. RETURN ON COMMON EQUITY**

20  
21 B2M LP's evidence reflects a return on equity ("ROE") of 8.98% as a placeholder for  
22 2020 based on the Cost of Capital Parameters released by the OEB on November 22,  
23 2018, for rates effective January 1, 2019. It is calculated according to the OEB's  
24 formulaic approach in Appendix B of the Cost of Capital for Ontario's Regulated  
25 Utilities report, dated December 11, 2009 (EB-2009-0084).

---

<sup>1</sup> Refer to Exhibit G-01-02 page 2.

Witness: Samir Chhelavda

1 As set out above, the Applicant will update the equity cost of capital for the 2020 Test  
2 Year by using the 2020 ROE to be released by the OEB in the fall of 2019.

3  
4 **4. DEEMED SHORT-TERM DEBT**

5  
6 The OEB has determined that the deemed amount of short-term debt that should be  
7 factored into rate setting be fixed at 4% of rate base. The deemed short-term rate of  
8 2.82% is being used by B2M LP as a placeholder for 2020 and is based on the September  
9 2018 average three-month bankers' acceptance rate of 1.923% and the 0.9% average  
10 annual spread from the Cost of Capital Parameters released by the OEB on November 22,  
11 2018, for rates effective January 1, 2019.

12  
13 B2M LP will update the short-term debt rate for the 2020 Test year based on the 2020  
14 deemed short-term debt rate to be released by the OEB in the fall of 2019.

15  
16 **5. LONG-TERM DEBT**

17  
18 The OEB has determined that the deemed amount of long-term debt that should be  
19 factored into rate setting be fixed at 56% of rate base, in B2M LP's 2015 to 2019  
20 transmission rate application (EB-2015-0026). The forecast weighted average long-term  
21 debt rate is calculated to be 3.08% for 2020.

22  
23 B2M LP will update the long-term debt rate for the 2020 Test year based on B2M LP's  
24 weighted average of its existing debt rate and the September 2019 Consensus Forecast,  
25 consistent with the proposed update of the return on common equity and deemed short-  
26 term interest rate.

1 **6. COST OF LONG-TERM DEBT**

2  
3 **6.1 B2M LP LONG-TERM DEBT**

4  
5 Hydro One Inc. provides treasury services to B2M LP. B2M LP issues debt to Hydro One  
6 Inc. to reflect debt issued by Hydro One Inc. to third-party public debt investors. In  
7 2015, Hydro One Inc. issued a five-year note to third-party investors to finance 100% of  
8 B2M LP's debt, which matures on April 30, 2020. Third-party public debt investors hold  
9 all of the long-term debt issued by Hydro One Inc. The debt portfolio for B2M LP is  
10 detailed in Exhibit G, Tab 1, Schedule 3.

11  
12 **6.2 CREDIT RATINGS**

13  
14 As an issuing entity, Hydro One Inc. obtains credit ratings from credit rating agencies as  
15 a requirement to issue medium term notes in the Canadian public debt markets. Table 2  
16 lists the credit ratings of Hydro One Inc.'s debt obligations by DBRS, Moody's Investors  
17 Service and Standard & Poor's Rating Services:

18  
19 **Table 2 - Credit Ratings for Hydro One Inc.**

Rating Agency	Short-term Debt	Long-term Debt
Standard & Poor's Rating Services (S&P)	A-1(low)	A-
DBRS	R-1(low)	A(high)
Moody's Investors Service (Moody's)	Prime-2	Baa1

20  
21 The most recent rating agency reports are available in Hydro One Transmission's EB-  
22 2019-0082 proceeding at Exhibit A, Tab 6, Schedule 3.

Witness: Samir Chhelavda

1 **6.3 COST OF LONG-TERM DEBT**

2  
3 The long-term debt rate for 2020 is calculated as the weighted average cost rate on  
4 existing debt, which matures on April 30, 2020, and forecast debt planned to be issued in  
5 2020. The proposed weighted average long-term debt rate for 2020 is 3.08%. Details  
6 used in the calculation of the forecast long-term debt rate are presented at Exhibit G, Tab  
7 1, Schedule 2, Page 1.

8  
9 **6.4 FORECAST DEBT**

10  
11 The OEB has determined in its Cost of Capital Report that the rate for new debt that is  
12 held by a third-party public debt investor will be the prudently negotiated contract rate.  
13 This would include recognition of premiums and discounts.

14  
15 B2M LP's planned borrowing requirement in 2020 is \$273.5 million, based on its most  
16 recent forecast. B2M LP's borrowing requirements are driven entirely by the maturity of  
17 its existing debt. Unlike other transmission companies such as HONI, which have capital  
18 structures that include a portfolio of embedded debt with remaining maturities ranging  
19 from less than one year to more than 40 years, the entire amount of B2M LP's debt  
20 matures at once in 2020.

21  
22 B2M LP issued a five-year note in 2015 for the entire amount of its debt. The timing of  
23 this issuance yielded a very low rate that provided ratepayers with substantially low long-  
24 term debt costs over the last five years. For planning purposes it is assumed that B2M  
25 LP's new debt issues will be distributed evenly over the standard terms of 5, 10 and 30-  
26 years. These are the standard maturity terms preferred by investors and represent the  
27 typical financing terms that Hydro One Inc. utilizes to execute its financing strategy and  
28 raise required funds.

Witness: Samir Chhelavda

1 For the purpose of this application, B2M LP's evidence reflects a long-term debt rate of  
2 3.08%, as a placeholder for 2020. From January to April 2020, the cost of existing debt of  
3 1.64% is applied and, from April 30, 2020, to December 31, 2024, B2M LP has applied  
4 the long-term debt rate based on HONI's forecast for new long-term debt rate calculation  
5 for 2020, reflecting the April 2019 Consensus Forecasts and the average of indicative  
6 new issue spreads for April 2019.

7  
8 Table 3 lists the fixed rate notes that Hydro One Inc. plans to issue for B2M LP in 2020,  
9 as shown in lines 2 to 3 of Exhibit G, Tab 1, Schedule 2, page 1.

10  
11 **Table 3 - Forecast Debt Issues for 2020**

<b>Principal Amount (\$Millions)</b>	<b>Term (Years)</b>	<b>Coupon</b>
91.2	5	2.91%
91.2	10	3.42%
91.2	30	4.06%

12  
13 B2M LP has calculated the weighted average debt rate to be 3.08% for 2020 and the  
14 forecast new long-term debt rate of 3.63% for 2021, as shown in Exhibit G, Tab 1,  
15 Schedule 2, page 1 and 2, respectively.

16  
17 B2M LP assumes that for rates effective January 1, 2020, the forecast interest rate for  
18 B2M LP's debt issues will be updated based on the September 2019 Consensus Forecasts  
19 and the average of indicative new issue spreads for September 2019 that will be obtained  
20 from the Hydro One Medium Term Note ("MTN") dealer group for each planned  
21 issuance term.

22  
23 The future refinancing rate on 100% of B2M LP's long-term debt in 2020 is unknown  
24 and could therefore have a material impact on B2M LP's financial performance if not

Witness: Samir Chhelavda

1 accounted for. B2M LP proposes to update the cost of long-term debt at the first annual  
2 update for rates in 2021, to reflect the actual market rate achieved on the long-term debt it  
3 will issue. Based on the current assumed forecast rates, the cost of debt for 2021 would  
4 be 3.63%. In the alternative, if approval to update the long-term debt at the first annual  
5 update for rates in 2021 is not granted, B2M LP proposes to apply the forecast rate of  
6 3.63% for new long-term debt beginning in 2020 to determine the cost of debt during the  
7 five-year period.

#### 9 **6.5 INTEREST RATES ON 2020 FORECAST DEBT ISSUES**

10  
11 B2M LP's borrowing will be financed at market rates applicable to Hydro One Inc.  
12 Table 4 summarizes the derivation of the forecast Hydro One Inc. yields for each of the  
13 planned issuance terms for 2020.

14  
15 **Table 4 - Forecast Yield for 2020 Issuance Terms**

	2020		
	5-year	10-year	30-year
<b>Government of Canada</b>	1.95%	2.10%	2.39%
<b>Hydro One Spread</b>	0.96%	1.32%	1.67%
<b>Forecast Hydro One Yield</b>	2.91%	3.42%	4.06%

16  
17 Each rate comprises the forecast Government of Canada bond yield plus the Hydro One  
18 Inc. credit spread applicable to that term. The ten-year Government of Canada bond  
19 yield forecast for 2020 is based on the average of the three-month and 12-month forecast  
20 from the April 2019 Consensus Forecast. The ten-year Government of Canada bond  
21 yield forecast for 2020 is based on the April 2019 Long-Term Consensus Forecast. The  
22 five-year Government of Canada bond yield forecasts are derived by subtracting the April  
23 2019 average spreads (five-year to ten-year for the five-year forecast) from the ten-year

Witness: Samir Chhelavda

1 Government of Canada bond yield forecast. The thirty-year Government of Canada bond  
2 yield forecasts are derived by adding the April 2019 average spreads (30-year to ten-year  
3 for the 30-year forecast) to the ten-year Government of Canada bond yield forecast.  
4 Hydro One's credit spreads over the Government of Canada bonds are based on the  
5 average of indicative new issue spreads for April 2019 obtained from the Company's  
6 MTN dealer group for each planned issuance term.

7  
8 B2M LP assumes that, for rates effective January 1, 2020, the forecast interest rate for  
9 Hydro One Inc.'s debt issues will be based on the September 2019 Consensus Forecasts  
10 and the average of indicative new issue spreads for September 2019 that will be obtained  
11 from the Hydro One Inc. MTN dealer group for each planned issuance term.

## 12 13 **6.6 TREASURY OM&A COSTS**

14  
15 Treasury OM&A costs are incurred to:

- 16 • execute borrowing plans and issue commercial paper and long-term debt;
- 17 • ensure compliance with securities regulations, bank and debt covenants;
- 18 • manage B2M LP's daily liquidity position, control cash, and manage the  
19 company's bank accounts;
- 20 • settle all transactions and manage relationships with creditors; and
- 21 • communicate with debt investors, banks and credit rating agencies.

22  
23 Treasury OM&A costs are provided in the long-term debt schedules for the Bridge and  
24 Test years in Exhibit G, Tab 1, Schedule 2 and are summarized in Table 5:

Witness: Samir Chhelavda

1

**Table 5 - Forecast Treasury OM&A Costs**

<b>Year</b>	<b>Amount (\$Millions)</b>	<b>Line</b>	<b>Page</b>
2020	0.1	6	1

2

3

**6.7 OTHER FINANCING-RELATED FEES**

4

5

Column (e) of Exhibit G, Tab 1, Schedule 2 ("Premium, Discount and Expenses") represents the costs of issuing debt. These costs are specific to each debt issue and include commissions, legal fees, debt discounts or premiums on issues and re-openings of issues relative to par, and hedge gains or losses.

9

10

Other financing-related fees include the Transmission allocation of Hydro One Inc.'s standby credit facility, annual credit rating agency, filing fees to security regulators, letters of credit, banking, custodial and trustee fees. These fees are summarized in Table 6 and are also provided in the long term debt schedules for the Bridge and Test years in Exhibit G, Tab 1, Schedule 2:

15

16

**Table 6 - Forecast Other Financing-Related Fees**

<b>Year</b>	<b>Amount (\$Millions)</b>	<b>Line</b>	<b>Page</b>
2020	0.2	7	1

Bruce to Milton Partnership  
Cost of Long-Term Debt Capital  
Test Year (2020)  
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered (\$Millions)	Premium Discount and Expenses (\$Millions)	Net Capital Employed		Effective Cost Rate	Total Amount Outstanding		Avg. Monthly Averages (\$Millions)	Carrying Cost (\$Millions)	Projected Average Embedded Cost Rates
						Total Amount (\$Millions)	Per \$100 Principal Amount (Dollars)		at 12/31/2019 (\$Millions)	at 12/31/2020 (\$Millions)			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	30-Jun-15	1.640%	30-Apr-20	274.3	1.0	273.3	99.64	1.72%	274.3	0.0	84.4	1.5	
2	30-Apr-20	2.912%	30-Apr-25	91.4	0.5	91.0	99.50	3.02%	0.0	91.4	63.3	1.9	
3	30-Apr-20	3.418%	30-Apr-30	91.4	0.5	91.0	99.50	3.48%	0.0	91.4	63.3	2.2	
4	30-Apr-20	4.059%	30-Apr-50	91.4	0.5	91.0	99.50	4.09%	0.0	91.4	63.3	2.6	
5		<b>Subtotal</b>							<u>274.3</u>	<u>274.3</u>	<u>274.3</u>	<u>8.2</u>	
6		Treasury OM&A costs										0.1	
7		Other financing-related fees										0.2	
8		<b>Total</b>							<u><u>274.3</u></u>	<u><u>274.3</u></u>	<u><u>274.3</u></u>	<u><u>8.4</u></u>	<u><u>3.08%</u></u>

Filed: 2019-07-31

EB-2019-0178

Exhibit G

Tab 1

Schedule 2

Page 2 of 2

B2M LP  
 Cost of Long-Term Debt Capital  
 2021  
 Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered (\$Millions)	Premium Discount and Expenses (\$Millions)	Net Capital Employed		Effective Cost Rate	Total Amount Outstanding		Avg. Monthly Averages (\$Millions)	Carrying Cost (\$Millions)	Projected Average Embedded Cost Rates
						Total Amount (\$Millions)	Per \$100 Principal Amount (Dollars)		at 12/31/2020 (\$Millions)	at 12/31/2021 (\$Millions)			
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	30-Apr-20	2.912%	30-Apr-25	91.4	0.5	91.0	99.50	3.02%	91.4	91.4	91.4	2.8	
2	30-Apr-20	3.418%	30-Apr-30	91.4	0.5	91.0	99.50	3.48%	91.4	91.4	91.4	3.2	
3	30-Apr-20	4.059%	30-Apr-50	91.4	0.5	91.0	99.50	4.09%	91.4	91.4	91.4	3.7	
4		<b>Subtotal</b>							274.3	274.3	274.3	9.7	
5		Treasury OM&A costs										0.1	
6		Other financing-related fees										0.2	
7		<b>Total</b>							274.3	274.3	274.3	10.0	3.63%

**B2M LP**  
 Debt and Equity Summary  
 Historical Years (2015, 2016, 2017, 2018) and Bridge Year (2019)  
 As at December 31  
 (\$ Millions)

Updated Line No.	Particulars	Amount Outstanding 2015	Amount Outstanding 2016	Amount Outstanding 2017	Amount Outstanding 2018	Amount Outstanding 2019
		Actual (a)	Actual (b)	Actual (c)	Actual (d)	Bridge (e)
I	Long-term debt	293.3	288.9	285.1	281.3	277.5
2	Short-term debt	20.5	20.5	20.5	20.5	19.8
3	Preference shares	-	-	-	-	-
4	Common equity	218.2	207.6	207.8	205.5	198.2

**B2M LP**  
 Summary of Cost of Capital  
 Test Year 2020  
 Utility Capital Structure  
 Year Ending December 31  
 (\$ Millions)

Line No.	Particulars	2020		Cost	Return
		(\$M)	%	Rate	(\$M)
		(a)	(b)	(c)	(d)
I	Long-term debt	274.3	56.0%	3.1%	8.4
2	Short-term debt	19.6	4.0%	2.8%	0.6
3	Deemed long-term debt	0.0	0.0%	0.0%	0.0
4	Total debt	293.9	60.0%	3.1%	9.0
5	Common equity	196.0	40.0%	9.0%	17.6
6	Total rate base	489.9	100.0%	5.4%	26.6

**B2M LP**  
Summary of Cost of Capital  
Last OEB-approved year (2019)  
Utility Capital Structure  
Year Ending December 31  
(\$ Millions)

Line No.	Particulars	2019			
		(\$M)	%	Cost Rate (%)	Return (\$M)
		(a)	(b)	(c)	(d)
1	Long-term debt	277.5	56.0%	1.8%	5.0
2	Short-term debt	19.8	4.0%	2.8%	0.6
3	Deemed long-term debt	0.0	0.0%	1.8%	0.0
4	Total debt	297.3	60.0%	1.9%	5.5
5	Common equity	198.2	40.0%	9.0%	17.8
6	Total rate base	495.6	100.0%	4.7%	23.3

## REGULATORY ACCOUNTS

### 1. INTRODUCTION

The purpose of this Exhibit is to provide a description of B2M LP's regulatory accounts and B2M LP's proposal with respect to regulatory account requests and disposition. The regulatory accounts reported by B2M LP have been established consistent with the Ontario Energy Board's ("OEB") requirements as set out in the Accounting Procedures Handbook, subsequent OEB direction, or as per specific requests initiated by B2M LP. B2M LP's outstanding regulatory account balances are summarized in Table 1 below:

**Table 1 - Summary of Regulatory Account Balances (\$ Millions)**

Description	US of A Account Ref.	Balance as at Dec 31, 2015	Balance as at Dec 31, 2016	Balance as at Dec. 31, 2017	Balance as at Dec. 31, 2018	Balance as at Dec. 31, 2019 (Forecast)
Forgone Revenue Deferral Account	1508	0.0	0.0	1.1	(1.6)	(0.1)
Tax Rate and Rule Changes Variance Account	1592	0.0	0.0	0.0	0.0	0.0
<b>Total Regulatory Accounts</b>		<b>0.0</b>	<b>0.0</b>	<b>1.1</b>	<b>(1.6)</b>	<b>(0.1)</b>

The forecast interest for 2019 is calculated by applying interest on the December 31, 2018, year-end principal balances less any amounts approved for disposition in 2019, using OEB prescribed interest rates, as per the Bankers' Acceptances three-month rate plus a spread of 25 basis points.

Information on each account and its balance is described in Section 2.0 of this Exhibit, with a detailed continuity schedule for the period 2015 to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances presented in Exhibit H, Tab 1, Schedule 2.

Witness: Samir Chhelavda

1 No adjustments have been made to account balances that were previously approved by  
2 the OEB on a final basis.

3

## 4 **2. DESCRIPTION OF REGULATORY ACCOUNTS**

5

6 The OEB approved or required the establishment of two regulatory accounts for B2M  
7 LP; which are described herein. As presented in Exhibit H, Tab 1, Schedule 2, there is a  
8 small 2019 forecast balance for regulatory accounts in the amount of (\$55,379). As such,  
9 B2M LP is requesting to adjust its revenue requirement over a one-year period  
10 commencing January 1, 2020.

11

### 12 **2.1 TAX RATE AND RULE CHANGES VARIANCE ACCOUNT**

13

14 This account was created as a result of the OEB's decision of December 29, 2015 (EB-  
15 2015-0026) and in accordance with the accounting order approved in the Final Order on  
16 January 14, 2016. The account will track the tax impact to B2M LP of:

- 17 • Differences that result from a legislative or regulatory change to the tax rates or  
18 rules compared to costs approved by the Board as part of 2015 to 2019  
19 transmission rates; and
- 20 • Differences that result from a change in, or a disclosure of, a new assessment or  
21 administrative policy that is published in the public tax administration or  
22 interpretation bulletins by relevant federal or provincial tax authorities.

23

24 As at December 31, 2018, B2M LP had recognized a balance of \$0.0 million, inclusive of  
25 accrued interest. This account is reported to the OEB on a quarterly basis, consistent with  
26 the OEB's Reporting and Record Keeping Requirements.

1 B2M LP proposes continuance of this account to track the revenue requirement impact of  
2 legislative or regulatory changes to tax rates or rules compared to costs approved by the  
3 OEB as part of B2M LP's 2020 to 2024 transmission rates.

## 4 5 **2.2 FORGONE REVENUE DEFERRAL ACCOUNT**

6  
7 This account was created as a result of the OEB's decision on June 8, 2017 (EB-2016-  
8 0349) and in accordance with the accounting order approved in the final Decision and  
9 Order on June 29, 2017. The account tracked the difference between revenue earned by  
10 B2M LP under the interim 2017 rates set at the 2016 Uniform Transmission Rates  
11 ("UTR") level, and the revenues that would have been received under the approved 2017  
12 UTR based on the OEB approved 2017 load forecast. The balance was subsequently  
13 recovered from ratepayers over a one-year period ended December 31, 2018. As part of  
14 the OEB's decision on May 10, 2018 (EB-2017-0380), the OEB directed B2M LP to  
15 record the difference between revenue earned by B2M LP under the interim 2018 rates  
16 set at the 2017 UTR level, and the revenues that would have been received under the  
17 approved 2018 UTR based on the OEB-approved 2018 load forecast. The majority of this  
18 balance is currently being returned to ratepayers over a one-year period ending December  
19 31, 2019.

20  
21 As at December 31, 2018, B2M LP had recognized a liability balance of \$1.6 million,  
22 inclusive of accrued interest. This account is reported to the OEB on a quarterly basis,  
23 consistent with the OEB's Reporting and Record Keeping Requirements.

24  
25 Included in the balance submitted for approval is interest forecast through to December  
26 31, 2019, to reflect carrying charges anticipated through to the proposed implementation  
27 date, and reduced by \$1.6 million liability balance approved for disposition in 2019. This  
28 will result in a forecast liability account balance of (\$55,379) at the end of 2019. As noted

Witness: Samir Chhelavda

1 above, B2M LP is requesting this balance for disposition over a one-year period  
2 commencing January 1, 2020.

3  
4 B2M LP proposes continuance of this account to record forgone revenue in future years  
5 when annual rate revenue requirement updates are made throughout the 2020 to 2024  
6 term.

7  
8 **3. DESCRIPTION OF NEW REGULATORY ACCOUNTS REQUESTED**

9  
10 B2M LP proposes a new earnings sharing mechanism (“ESM”) deferral account,  
11 effective January 1, 2020, to record any over-earnings realized during any year of the  
12 five-year term through B2M LP’s transmission revenue. B2M LP proposes to share with  
13 customers 50% of any earnings that exceed the regulatory return on equity reflected in  
14 this Application by more than 100 basis points in any year of the five-year term.

15  
16 The use of an ESM will provide protection for customers if forecasts differ from actual  
17 results over the five-year period. The 100 basis points would satisfy the OEB-defined  
18 materiality threshold and have a significant impact on B2M LP’s operations. It is also  
19 consistent with the proposal put forth by HONI in its 2020 to 2022 Transmission  
20 Application (EB-2019-0028).

21 The customer share of the earnings will be adjusted for any tax impacts and will be  
22 credited to a new deferral account that will be put forward for disposition at the time of  
23 B2M LP’s next rates rebasing application. A draft accounting order is provided as  
24 Appendix A to this Exhibit.

1 **4. ACCOUNTING AND CONTROL PROCESS**

2

3 The accounts noted above will continue to be managed in a consistent manner. When  
4 applicable, they will be updated monthly and interest applied to the monthly opening  
5 principal balance in this account according to the Board-approved rate. Balances will be  
6 reported to the Board as part of the quarterly reporting process. The outstanding  
7 balances, whether in a debit or credit position, will be submitted for approval to the  
8 Board as part of a future B2M LP rate application.

1                                   **APPENDIX A: B2M LP ACCOUNTING ORDER**

2  
3                                   **Transmission Accounting Order – ESM Deferral Account**

4  
5 B2M LP proposes the establishment of a new “Earnings Sharing Mechanism (“ESM”)  
6 Deferral Account” to record any over-earnings realized during any year of the five-year  
7 term through B2M LP’s transmission revenue.

8  
9 The account will be established as Account 2435, Accrued Rate-Payer Benefit effective  
10 January 1, 2020. B2M LP will record interest on any balance in the sub-account using  
11 the interest rates set by the OEB. Simple interest will be calculated on the opening  
12 monthly balance of the account until the balance is fully disposed.

13  
14 The following outlines the proposed accounting entries for this deferral account.

15

16	<b>USofA #</b>	<b>Account Description</b>
17	DR: 4395	Rate-Payer Benefit Including Interest
18	CR: 2435	Accrued Rate-Payer Benefit

19  
20 Initial entry to record the over-earnings realized in any year of the five-year term.

21

22	<b>USofA #</b>	<b>Account Description</b>
23	DR: 4395	Rate-Payer Benefit Including Interest
24	CR: 2435	Accrued Rate Payer Benefit

25  
26 To record interest improvement on principal balance of ESM deferral account.

		2015								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-15	Transactions Debit / (Credit) during 2015 excluding interest and adjustments	Board-Approved Disposition during 2015	Closing Principal Balances as of Dec 31-15 Adjusted for Dispositions	Opening Interest Amounts as of Jan-1-15	Interest Disposition during 2015 - instructed by Board	Interest Jan-1 to Dec-31-15	Closing Interest Balance as at Dec 31 -15 balance adjusted for disposition during 2015	2015 total balance (for evidence)
Foregone Revenue Deferral Account	1508									
<b>Total Transmission Regulatory Accounts Requesting for Disposition</b>		-	-	-	-	-	-	-	-	-
Tax Rate and Rule Changes Variance Account	1592									
<b>Total Transmission Accounts NOT requesting Disposition</b>		-	-	-	-	-	-	-	-	-
<b>Total Transmission Regulatory Accounts</b>		-	-	-	-	-	-	-	-	-

Witness: Samir Chhelavda

		2016								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions Debit / (Credit) during 2016 excluding interest and adjustments	Board-Approved Disposition during 2016	Closing Principal Balances as of Dec 31-16 Adjusted for Dispositions	Opening Interest Amounts as of Jan-1-16	Interest Disposition during 2016 - instructed by Board	Interest Jan-1 to Dec-31-16	Closing Interest Balance as at Dec 31 -16 balance adjusted for disposition during 2016	2016 total balance (for evidence)
Foregone Revenue Deferral Account	1508									
<b>Total Transmission Regulatory Accounts Requesting for Disposition</b>		-	-	-	-	-	-	-	-	-
Tax Rate and Rule Changes Variance Account	1592									
<b>Total Transmission Accounts NOT requesting Disposition</b>		-	-	-	-	-	-	-	-	-
<b>Total Transmission Regulatory Accounts</b>		-	-	-	-	-	-	-	-	-

Witness: Samir Chhelavda

		2017								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-17	Transactions Debit / (Credit) during 2017 excluding interest and adjustments	Board-Approved Disposition during 2017	Closing Principal Balances as of Dec 31-17 Adjusted for Dispositions	Opening Interest Amounts as of Jan-1-17	Interest Disposition during 2017 - instructed by Board	Interest Jan-1 to Dec-31-17	Closing Interest Balance as at Dec 31 -17 balance adjusted for disposition during 2017	2017 total balance (for evidence)
Foregone Revenue Deferral Account	1508	-	1,126,968		1,126,968	-	-	3,281	3,281	1,130,249
<b>Total Transmission Regulatory Accounts Requesting for Disposition</b>		-	<b>1,126,968</b>	-	<b>1,126,968</b>	-	-	<b>3,281</b>	<b>3,281</b>	<b>1,130,249</b>
Tax Rate and Rule Changes Variance Account	1592				-	-	-	-	-	-
<b>Total Transmission Accounts NOT requesting Disposition</b>		-	-	-	-	-	-	-	-	-
<b>Total Transmission Regulatory Accounts</b>		-	<b>1,126,968</b>	-	<b>1,126,968</b>	-	-	<b>3,281</b>	<b>3,281</b>	<b>1,130,249</b>

Witness: Samir Chhelavda

		2018								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-18	Transactions Debit / (Credit) during 2018 excluding interest and adjustments	Board-Approved Disposition during 2018	Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions	Opening Interest Amounts as of Jan-1-18	Interest Disposition during 2018 - instructed by Board	Interest Jan-1 to Dec-31-18	Projected Interest Balance as at Dec 31 -18 balance adjusted for disposition during 2018	2018 total balance (for evidence)
Foregone Revenue Deferral Account	1508	1,126,968	(2,760,870)		(1,633,902)	3,281		(4,327)	(1,046)	(1,634,948)
<b>Total Transmission Regulatory Accounts Requesting for Disposition</b>		<b>1,126,968</b>	<b>(2,760,870)</b>	-	<b>(1,633,902)</b>	<b>3,281</b>	-	<b>(4,327)</b>	<b>(1,046)</b>	<b>(1,634,948)</b>
Tax Rate and Rule Changes Variance Account	1592	-		-	-	-	-	-	-	-
<b>Total Transmission Accounts NOT requesting Disposition</b>		<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Total Transmission Regulatory Accounts</b>		<b>1,126,968</b>	<b>(2,760,870)</b>	<b>-</b>	<b>(1,633,902)</b>	<b>3,281</b>	<b>-</b>	<b>(4,327)</b>	<b>(1,046)</b>	<b>(1,634,948)</b>

Witness: Samir Chhelavda

		2019								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-19	Transactions Debit / (Credit) during 2019 excluding interest and adjustments	Board-Approved Disposition during 2019	Closing Principal Balances as of Dec 31-19 Adjusted for Dispositions	Opening Interest Amounts as of Jan-1-19	Interest Disposition during 2019 - instructed by Board	Projected Interest Jan-1 to Dec-31-19	Projected Interest Balance as at Dec 31 -19 balance adjusted for disposition during 2019	2019 total balance (for evidence)
Foregone Revenue Deferral Account	1508	(1,633,902)		1,600,000	(33,902)	(1,046)		(20,431)	(21,477)	(55,379)
<b>Total Transmission Regulatory Accounts Requesting for Disposition</b>		<b>(1,633,902)</b>	<b>-</b>	<b>1,600,000</b>	<b>(33,902)</b>	<b>(1,046)</b>	<b>-</b>	<b>(20,431)</b>	<b>(21,477)</b>	<b>(55,379)</b>
Tax Rate and Rule Changes Variance Account	1592	-		-	-	-		-	-	-
<b>Total Transmission Accounts NOT requesting Disposition</b>		<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>	<b>-</b>
<b>Total Transmission Regulatory Accounts</b>		<b>(1,633,902)</b>	<b>-</b>	<b>1,600,000</b>	<b>(33,902)</b>	<b>(1,046)</b>	<b>-</b>	<b>(20,431)</b>	<b>(21,477)</b>	<b>(55,379)</b>

Witness: Samir Chhelavda

**COST ALLOCATION AND RATE DESIGN**

**1. COST ALLOCATION**

All assets associated with B2M LP are classified as Network assets, consistent with the cost allocation methodology approved by the Board for B2M LP in proceeding EB-2015-0026. A listing of the B2M LP assets by functional category is provided below in Table 1. Accordingly, all of the rates revenue requirement associated with B2M LP's transmission assets will be allocated to the Network pool.

**Table 1 - B2M LP Assets by Functional Category**

<b>Circuit</b>	<b>Section</b>	<b>From</b>	<b>To</b>	<b>Functional Category</b>
B560V	1	Bruce A TS	Willow Creek JCT	Network
B560V	3	Willow Creek JCT	Milton SS	Network
B561M	1	Bruce B SS	Bruce JCT	Network
B561M	4	Bruce JCT	Bruce JCT	Network
B561M	2	Bruce JCT	Willow Creek JCT	Network
B561M	3	Willow Creek JCT	Milton SS	Network

The B2M LP Network rates revenue requirement for the purpose of setting uniform transmission rates effective on the first day of each test year is \$35.7 million for 2020, \$36.2 million for 2021, \$36.7 million for 2022, \$37.3 million for 2023, and \$37.8 million for 2024 as determined per Exhibit A, Tab 4, Schedule 1.

**2. CHARGE DETERMINANTS**

There are no customer delivery points supplied directly from the B2M LP assets, and as such the B2M LP Network charge determinant for the purpose of setting Uniform Transmission Rates is zero.

Witness: Henry Andre/Clement Li

1           **OVERVIEW OF UNIFORM TRANSMISSION SYSTEM RATES**

2  
3           **1. INTRODUCTION**

4  
5           Transmission rates in Ontario have been established on a uniform basis for all  
6           transmitters in Ontario since April 30, 2002, as per the OEB's Decision in RP-2001-  
7           0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Uniform Transmission  
8           Rates ("UTR") Schedules, which were effective on January 1, 2019, as part of the OEB's  
9           Decision and Interim Rate Order in EB-2018-0130, with approved interim 2019 UTR  
10          Order in EB-2018-0326 issued on December 20, 2018, are filed as Exhibit I, Tab 3,  
11          Schedule 1, Attachment 1. Exhibit I, Tab 3, Schedule 1, Attachment 2 shows the revenue  
12          requirement and charge determinant details used to derive the currently approved interim  
13          2019 UTRs.

14  
15          Since rates are established on a uniform basis, B2M LP's requested revenue requirement  
16          is a contributor to the total revenue requirement to be collected from the provincial UTR.  
17          The revenue requirement for all the other transmitters in the province approved to  
18          participate in the UTRs must be added to that of B2M LP in order to calculate the total  
19          transmission revenue requirement to be collected via the UTR.<sup>1</sup>

20  
21          The total revenue requirement from all transmitters must be allocated to the Network,  
22          Line Connection and Transformation Connection rate pools in order to establish uniform  
23          rates by pool. The revenue requirement for B2M LP will be allocated to the Network rate  
24          pool, as discussed in Exhibit I, Tab 1, Schedule 1. The revenue requirement by rate pool  
25          for the other transmitters is based on the proportions established by HONI Transmission's  
26          Cost Allocation process. Once the revenue requirement by rate pool has been established,

---

<sup>1</sup> The other four transmitters currently included in the UTRs are Hydro One Networks Transmission, Hydro One Sault Ste. Marie (formerly Great Lakes Power Transmission Inc.), Canadian Niagara Power Inc., and Five Nations Energy Inc.

Witness: Henry Andre/Clement Li

1 rates are determined by applying the Provincial charge determinants for each pool to the  
2 total revenue for each pool. The Provincial charge determinants are the sum of all charge  
3 determinants, by rate pool, approved by the Board for each of the transmitters  
4 participating in the UTR.

5

6 The proposed 2020 UTR schedules are provided in Exhibit I, Tab 4, Schedule 1,  
7 Attachment 1; and the revenue requirement and charge determinants details used to  
8 calculate the 2020 UTRs are provided in Exhibit I, Tab 4, Schedule 1, Attachment 2. The  
9 proposed 2020 UTR calculation includes the currently approved values for HONI  
10 Transmission, Hydro One Sault Ste. Marie, Canadian Niagara Power Inc., and Five  
11 Nations Energy Inc.

12

## 13 **2. BILL IMPACTS**

14

15 The impact of transmission rates on a customer's total bill varies between transmission-  
16 connected and distribution-connected customers. The approach used in HONI's  
17 Transmission Rate Application (EB-2019-0082) has been adopted to determine the  
18 impact of proposed changes to transmission rates on an average customer's bill. Table 1  
19 shows the estimated average transmission cost as a percentage of the total bill for a  
20 transmission- and a distribution-connected customer.



1 **Table 2 - Average Bill Impacts on Transmission and Distribution-connected**  
 2 **Customers**

	2019*	2020	2021	2022	2023	2024
Rates Revenue Requirement (\$ millions)	32.8	35.7	36.2	36.7	37.3	37.8
% Increase in Rates Revenue Requirement over prior year		8.8%	1.6%	1.4%	1.4%	1.4%
% Impact of load forecast change		0.0%	0.0%	0.0%	0.0%	0.0%
<b>Net Impact on Average Transmission Rates</b>		<b>0.18%</b>	<b>0.03%</b>	<b>0.03%</b>	<b>0.03%</b>	<b>0.03%</b>
<i>Transmission as a % of Tx - connected customer's Total Bill</i>		7.4%	7.4%	7.4%	7.4%	7.4%
<b>Estimated Average Bill Impact</b>		<b>0.01%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>
<i>Transmission as a % of Dx - connected customer's Total Bill</i>		6.2%	6.2%	6.2%	6.2%	6.2%
<b>Estimated Average Bill Impact</b>		<b>0.01%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>	<b>0.00%</b>

\* 2019 rates revenue requirement as per the OEB's Decision and Order for B2M LP's Transmission Revenue Requirement application (EB-2018-0320, Schedule A, Exhibit 1.0), issued on 20<sup>th</sup> December, 2018.

3  
 4 The total bill impact for a typical medium density residential (Hydro One R1) customer  
 5 consuming 750 kWh monthly and a typical General Service Energy less than 50 kW  
 6 (Hydro One GSe < 50 kW) customer consuming 2,000 kWh monthly is determined based  
 7 on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as  
 8 detailed in Table 3.

1

**Table 3 - Typical Customer Monthly Bill Impacts**

	<b>Typical Medium Density (Hydro One R1) Residential Customer 750 kWh</b>	<b>Typical General Service Energy less than 50 kW (Hydro One GSe &lt; 50kW) Customer 2,000 kWh</b>
Total Bill as of May 1, 2018 <sup>1</sup>	\$124.30	\$389.14
RTSR included in R1 Customer's Bill (based on 2019 Interim UTR)	\$11.94	\$25.21
<i>Estimated 2020 Monthly RTSR<sup>2</sup></i>	\$11.96	\$25.25
<b>2020 increase in Monthly Bill</b>	<b>\$0.02</b>	<b>\$0.04</b>
<i>2020 increase as a % of total bill</i>	<i>0.02%</i>	<i>0.01%</i>
<i>Estimated 2021 Monthly RTSR<sup>2</sup></i>	\$11.97	\$25.26
<b>2021 increase in Monthly Bill</b>	<b>\$0.00</b>	<b>\$0.01</b>
<i>2021 increase as a % of total bill</i>	<i>0.00%</i>	<i>0.00%</i>
<i>Estimated 2022 Monthly RTSR<sup>2</sup></i>	\$11.97	\$25.26
<b>2022 increase in Monthly Bill</b>	<b>\$0.00</b>	<b>\$0.01</b>
<i>2022 increase as a % of total bill</i>	<i>0.00%</i>	<i>0.00%</i>
<i>Estimated 2023 Monthly RTSR<sup>2</sup></i>	\$11.97	\$25.27
<b>2023 increase in Monthly Bill</b>	<b>\$0.00</b>	<b>\$0.01</b>
<i>2023 increase as a % of total bill</i>	<i>0.00%</i>	<i>0.00%</i>
<i>Estimated 2022 Monthly RTSR<sup>2</sup></i>	\$11.98	\$25.28
<b>2024 increase in Monthly Bill</b>	<b>\$0.00</b>	<b>\$0.01</b>
<i>2024 increase as a % of total bill</i>	<i>0.00%</i>	<i>0.00%</i>

<sup>1</sup>Total bill including HST, based on time-of-use commodity prices and distribution rates effective May 1, 2018 (implemented July 1, 2019) approved per Distribution Rate Order EB-2017-0049, issued on June 11, 2019 (includes impacts of all applicable components of the Fair Hydro Plan).

<sup>2</sup>The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for B2M LP's revenue disbursement allocator, as per the interim 2019 UTR Order (EB-2018-0326) issued on December 20, 2018.

Witness: Henry Andre/Clement Li

1           **CURRENT ONTARIO TRANSMISSION RATE SCHEDULES**

2

3       The current Uniform Transmission Rate (“UTR”) Schedules were approved as part of the  
4       2019 Decision and Interim Rate Order dated December 20, 2018 under EB-2018-0326.  
5       This approved rate schedule, and the revenue requirement and charge determinants for all  
6       transmitters used to establish the current UTRs and revenue disbursement allocators are  
7       included in the following attachments.

8

9       **Attachment 1:** 2019 Ontario Uniform Transmission Rate Schedules

10      **Attachment 2:** 2019 Uniform Transmission Rates and Revenue Disbursement Allocators

# 2019 ONTARIO UNIFORM TRANSMISSION

## RATE SCHEDULES

EB-2018-0326

**The rate schedule contained herein are interim and shall be effective and implemented as of January 1, 2019**

Issued: December 20, 2018  
Ontario Energy Board

## TRANSMISSION RATE SCHEDULES

### TERMS AND CONDITIONS

**(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

**(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

**(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of

Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

**(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

**(E) MARKET RULES** The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

## TRANSMISSION RATE SCHEDULES

**(F) METERING REQUIREMENTS** In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

**(G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

**(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a

## TRANSMISSION RATE SCHEDULES

distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

EFFECTIVE DATE:  
January 1, 2019

BOARD ORDER:  
EB-2018-0326

REPLACING BOARD ORDER:  
EB-2017-0359  
February 1, 2018

Page 4 of 6  
Ontario Uniform Transmission  
Rate Schedule

## TRANSMISSION RATE SCHEDULES

### RATE SCHEDULE: (PTS)

### PROVINCIAL TRANSMISSION RATES

#### **APPLICABILITY:**

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	<u>Monthly Rate (\$ per kW)</u>	
<b>Network Service Rate (PTS-N):</b>	<b>3.71</b>	
\$ Per kW of Network Billing Demand <sup>1,2</sup>		
<b>Line Connection Service Rate (PTS-L):</b>	<b>0.94</b>	
\$ Per kW of Line Connection Billing Demand <sup>1,3</sup>		
<b>Transformation Connection Service Rate (PTS-T):</b>	<b>2.25</b>	
\$ Per kW of Transformation Connection Billing Demand <sup>1,3,4</sup>		

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

#### Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

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

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

#### **TERMS AND CONDITIONS OF SERVICE:**

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

EFFECTIVE DATE:  
January 1, 2019

BOARD ORDER:  
EB-2018-0326

REPLACING BOARD ORDER:  
EB-2017-0359  
February 1, 2018

Page 5 of 6  
Ontario Uniform Transmission  
Rate Schedule

TRANSMISSION RATE SCHEDULES

**RATE SCHEDULE: (ETS)**

**EXPORT TRANSMISSION SERVICE**

---

***APPLICABILITY:***

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

**Export Transmission Service Rate (ETS):**

**Hourly Rate**

\$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

EFFECTIVE DATE:  
January 1, 2019

BOARD ORDER:  
EB-2018-0326

REPLACING BOARD ORDER:  
EB-2017-0359  
February 1, 2018

Page 6 of 6  
Ontario Uniform Transmission  
Rate Schedule

**2019 Interim Uniform Transmission Rates and Revenue Disbursement Allocators**

(for Period January 1, 2019 to December 31, 2019)

Transmitter	Revenue Requirement (\$)			
	Network	Line Connection	Transformation Connection	Total
FNEI	\$4,523,701	\$1,142,191	\$2,322,200	\$7,988,092
CNPI	\$2,631,736	\$664,488	\$1,350,977	\$4,647,201
HIN SSM	\$22,526,571	\$5,687,744	\$11,563,805	\$39,778,120
HIN	\$861,509,753	\$217,522,988	\$442,248,014	\$1,521,280,755
B2MLP	\$32,789,151	\$0	\$0	\$32,789,151
All Transmitters	\$923,980,911	\$225,017,411	\$457,484,996	\$1,606,483,319

Transmitter	Total Annual Charge Determinants (MW)**			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
HIN SSM	3,498.236	2,734.624	635.252	
HIN	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates (\$/kW-Month)	<b>3.71</b>	<b>0.94</b>	<b>2.25</b>	
FNEI Allocation Factor	<b>0.00490</b>	<b>0.00508</b>	<b>0.00508</b>	
CNPI Allocation Factor	<b>0.00285</b>	<b>0.00295</b>	<b>0.00295</b>	
GLPT Allocation Factor	<b>0.02438</b>	<b>0.02528</b>	<b>0.02528</b>	
HIN Allocation Factor	<b>0.93238</b>	<b>0.96669</b>	<b>0.96669</b>	
B2MLP Allocation Factor	<b>0.03549</b>	<b>0.00000</b>	<b>0.00000</b>	
Total of Allocation Factors	1.00000	1.00000	1.00000	

\*\* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.

Note 3: HIN SSM 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218, issued December 6, 2018.

Note 4: HIN Rates Revenue Requirement per OEB Decision EB-2018-0130 dated December 20, 2018.

Note 5: HIN Charge Determinants per OEB Decision EB-2018-0130 dated December 20, 2018.

Note 6: B2M LP 2018 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.

Note 7: Calculated data in shaded cells.



2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2019-0178

**The rate schedules contained herein shall be effective January 1, 2020**

Issued: Month, Year  
Ontario Energy Board

EFFECTIVE DATE:  
January 1, 2020

BOARD ORDER:  
EB-2019-0178

REPLACING BOARD ORDER:  
EB-2018-0326  
December 20, 2018

Page 1 of 6  
Ontario Uniform Transmission  
Rate Schedule

## TRANSMISSION RATE SCHEDULES

### TERMS AND CONDITIONS

**(A) APPLICABILITY** The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

**(B) TRANSMISSION SYSTEM CODE** The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

**(C) TRANSMISSION DELIVERY POINT** The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of

Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

**(D) TRANSMISSION SERVICE POOLS** The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

**(E) MARKET RULES** The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

## TRANSMISSION RATE SCHEDULES

**(F) METERING REQUIREMENTS** In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

**(G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation generator unit or energy storage facility are obtained after October 30, 1998; and (b) the generator unit nameplate rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage or solar generators; and (c) the Transmission Delivery Point through which the generator or energy storage facility is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments or expansions approved after October 30, 1998, to a generator or generation facility ~~unit~~ that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental generator nameplate capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for expansion of energy storage facilities or solar generators. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

**(H) EMBEDDED CONNECTION POINT** In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection

## TRANSMISSION RATE SCHEDULES

point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations:

- The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market.
- The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

EFFECTIVE DATE:  
January 1, 2020

BOARD ORDER:  
EB-2019-0178

REPLACING BOARD ORDER:  
EB-2018-0326  
December 20, 2018

Page 4 of 6  
Ontario Uniform Transmission  
Rate Schedule

## TRANSMISSION RATE SCHEDULES

### RATE SCHEDULE: (PTS)

### PROVINCIAL TRANSMISSION RATES

#### APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	<u>Monthly Rate (\$ per kW)</u>
<b>Network Service Rate (PTS-N):</b>	<b>3.72</b>
\$ Per kW of Network Billing Demand <sup>1,2</sup>	
<b>Line Connection Service Rate (PTS-L):</b>	<b>0.94</b>
\$ Per kW of Line Connection Billing Demand <sup>1,3</sup>	
<b>Transformation Connection Service Rate (PTS-T):</b>	<b>2.25</b>
\$ Per kW of Transformation Connection Billing Demand <sup>1,3,4</sup>	

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

#### Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

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

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

#### TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

EFFECTIVE DATE:  
January 1, 2020

BOARD ORDER:  
EB-2019-0178

REPLACING BOARD ORDER:  
EB-2018-0326  
December 20, 2018

Page 5 of 6  
Ontario Uniform Transmission  
Rate Schedule

TRANSMISSION RATE SCHEDULES

**RATE SCHEDULE: (ETS)**

**EXPORT TRANSMISSION SERVICE**

---

***APPLICABILITY:***

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

**Export Transmission Service Rate (ETS):**

**Hourly Rate**

\$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

***TERMS AND CONDITIONS OF SERVICE:***

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

**2020 Interim Uniform Transmission Rates and Revenue Disbursement  
 (for Period January 1, 2020 to December 31, 2020)**

Transmitter	Revenue Requirement (\$)			
	Network	Line Connection	Transformation Connection	Total
FNEI	\$4,523,701	\$1,142,191	\$2,322,200	\$7,988,092
CNPI	\$2,631,736	\$664,488	\$1,350,977	\$4,647,201
H1N SSM	\$22,526,571	\$5,687,744	\$11,563,805	\$39,778,120
H1N	\$861,509,753	\$217,522,988	\$442,248,014	\$1,521,280,755
B2MLP	\$35,673,488	\$0	\$0	\$35,673,488
All Transmitters	\$926,865,249	\$225,017,411	\$457,484,996	\$1,609,367,656

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates (\$/kW-Month)	<b>3.72</b>	<b>0.94</b>	<b>2.25</b>	
<b>FNEI</b> Allocation Factor	<b>0.00488</b>	<b>0.00508</b>	<b>0.00508</b>	
<b>CNPI</b> Allocation Factor	<b>0.00284</b>	<b>0.00295</b>	<b>0.00295</b>	
<b>H1N SSM</b> Allocation Factor	<b>0.02430</b>	<b>0.02528</b>	<b>0.02528</b>	
<b>H1N</b> Allocation Factor	<b>0.92949</b>	<b>0.96669</b>	<b>0.96669</b>	
<b>B2MLP</b> Allocation Factor	<b>0.03849</b>	<b>0.00000</b>	<b>0.00000</b>	
Total of Allocation Factors	1.00000	1.00000	1.00000	

*Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.*

*Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 with approved 2016 order under EB-2015-0354, issued January 14, 2016 and confirmed on November 9, 2017 (EB-2016-0160).*

*Note 3: H1N SSM 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218, issued December 6, 2018.*

*Note 4: H1N Rates Revenue Requirement per OEB Decision EB-2018-0130 dated December 20, 2018.*

*Note 5: H1N Charge Determinants per OEB Decision EB-2018-0130 dated December 20, 2018.*

*Note 6: B2MLP 2020 Revenue Requirement per Exhibit E, Tab 1, Schedule 1.*

*Note 7: Calculated data in shaded cells.*