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Vice President, Reliability Standards and Chief Regulatory Officer

BY EMAIL AND RESS

May 28, 2020

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

Dear Ms. Long,

Re: EB-2019-0082 – Hydro One Network Inc.'s 2020-2022 Transmission Custom IR Application and Evidence Filing – Draft Rate Order

Pursuant to the Ontario Energy Board's (the "Board" or "OEB") April 23, 2020 Decision and Order ("Decision") on Hydro One's Application for Electricity Transmission Revenue Requirements Beginning January 1, 2020 until December 31, 2022 (the "Application"), please find attached the draft revenue requirement/charge determinant order and a draft Uniform Transmission Rates ("UTRs") order with supporting schedules (together, the "Draft Rate Order" or "DRO"). In the Decision, the Board approved Hydro One's 2020 revenue requirement effective January 1, 2020 with updates to the UTRs that may be implemented effective July 1, 2020.

As directed in the Decision and by copy of this letter, all intervenors have been notified of this filing and of the fact that they have the opportunity to submit comments, if any, to the OEB by June 11, 2020 on the DRO. Since, as noted in the Decision, the OEB is temporarily waiving the paper copy filing requirement until further notice, Hydro One is only filing an electronic copy of the DRO.

Sincerely,

Frank D'Andrea

Frank D'Andrea

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O. 1998, c. 15, (Schedule B);

AND IN THE MATTER OF an application for electricity transmission revenue requirements beginning January 1, 2020 until December 31, 2022.

HYDRO ONE NETWORKS INC.

DRAFT RATE ORDER

OEB File No. EB-2019-0082

May 28, 2020

TABLE OF CONTENTS

1 INTRODUCTION

Hydro One Networks Inc. ("**Hydro One**") filed a three-year custom incentive rate-setting application with the Ontario Energy Board (the "**OEB**" or "**Board**") on March 21, 2019 under section 78 of the *Ontario Energy Board Act, 1998*, seeking approval of its electricity transmission revenue requirements effective from January 1, 2020 until December 31, 2022 (the "**Application**").

On April 23, 2020 the OEB issued its Decision and Order on the Application (the "**Decision**").[1] The Decision directs Hydro One to file a draft revenue requirement/charge determinant order and a draft Uniform Transmission Rates ("**UTR**s") rate order with supporting schedules (together, the "**Draft Rate Order"** or "**DRO**") by no later than May 28, 2020.[2] In the Decision, the OEB approves Hydro One's 2020 revenue requirement effective January 1, 2020 with updates to the UTRs that may be implemented effective July 1, 2020.[3]

The DRO is organized as follows:

1. Section 2: Revenue Requirement – This section provides an explanation of how the revenue requirement was calculated to reflect the OEB's Decision;
2. Sections 3 to 7: These sections provide additional details requested by the OEB or that are otherwise necessary to explain how Hydro One implemented the Decision and calculated the revenue requirement, as follows:
    a. Section 3: Capital Reductions and Forecasted In-service Additions – This section describes how capital spending was reduced at the OEB-cost

[1] OEB Decision and Order re Hydro One Networks Inc., Application for electricity transmission rates beginning January 1, 2020 until December 31, 2022, (EB-2019-0082), April 23, 2020 ("**Decision**")
[2] Decision, p. 184.
[3] Decision, p. 5.

category level (System Access, System Service, System Renewal, General Plant) and the impact on the forecasted in-service additions, at the OEB-cost category level;

b. Section 4: OM&A – This section describes how the 2020 operation, maintenance and administration ("**OM&A**") expense was adjusted to reflect the Decision including the OEB-imposed reduction and the inclusion of the non-service components of Hydro One's Other Post-Employment Benefits ("**OPEB**") costs as part of OM&A;

c. Section 5: Tax Considerations – This section provides updated tax schedules to support the revenue requirement and describes the tax impact of the Accelerated Investment Incentive ("**Accelerated CCA**"), the tax impact of capital expenditure reductions, and the tax impact of including the non-service component of OPEB costs as an OM&A expense, on revenue requirement;

d. Section 6: Deferral and Variance Accounts – This section describes the OEB-approved disposition of existing deferral and variance accounts, the accounts subject to specific OEB direction, a proposed modification to the methodology for calculating the Capital In-Service Variance Account ("**CISVA**"), and a request for a Transmission Foregone Revenue Deferral Account;

e. Section 7: Transmission Scorecard – This section describes how the OEB's direction on the Transmission Scorecard has been implemented.

3. Section 8: Rates – This section provides the exhibits which set out the load forecast, rates revenue requirement and charge determinants by rate pool, foregone revenue calculations, 2020 UTR schedule, and bill impacts, each in accordance with the Decision. This section also includes a discussion on UTR implementation options that the OEB may wish to consider when it carries out its process for updating the UTRs for all transmitters in Ontario, following completion of the current proceeding.

4. Section 9: Supporting Material – This section includes a number of Exhibits containing detailed supporting information, which are referenced throughout the DRO.

The Decision results in various reductions to the rates revenue requirement, including by virtue of the reductions to capital (resulting in lower rate base, lower depreciation expense, lower taxes and lower return on capital), the reduction to OM&A, and increase to external revenue. In 2021 and 2022, the OEB imposed a productivity factor, incremental stretch factor on capital and excluded working capital from the capital factor calculation further reducing revenue requirement. All of the foregoing is further detailed below and in Exhibits 1.0 through 1.9.

The various reductions to rates revenue requirement are also offset by the following four increases that necessarily result from the findings and directions in the Decision:

- First, Hydro One adjusted its 2020 OM&A to reflect that the non-service component of OPEB costs has been included as an incremental OM&A expense;
- Second, taxes have been adjusted to reflect the tax consequences of the Decision, including: (i) the reduction of capital expenditures, which reduces in-service additions, resulting in lower CCA claims and increased taxes and (ii) the treatment of the non-service component of OPEB costs as an OM&A expense reflects an accrued amount which is not deductible for tax purposes until the expense is incurred;
- Third, Deferral and Variance Account balances have been adjusted as a result of the approved disposition of the 2018 balance for the OPEB Cost Deferral Account and the calculation of interest on all Deferral and Variance account balances to June 30, 2020; and

- Fourth, the cost of long-term debt has been updated to reflect Hydro One's actual debt issuances in 2019 consistent with Hydro One's evidence and prior practice.[4]

The net result of applying the above adjustments is that the 2020 rates revenue requirement is approximately 2.6% lower than as presented in the Application,[5] although it is approximately 1.9% higher than the rates revenue requirement that was presented in Hydro One's Argument In-Chief to reflect the OEB's updated cost of capital parameters, as shown in Exhibit 1.0.[6]

2 DETERMINATION OF REVENUE REQUIREMENT

The revenue requirement for 2020 is derived using a cost of service approach while the revenue requirements for 2021 and 2022 are derived using the approved formulaic approach. Tables supporting the calculation of revenue requirement are included in Exhibits 1.0 to 1.9**.**

The following sections identify the adjustments made to revenue requirement to implement the findings in the Decision.

2.1 Summary of Rebasing Year (2020) Revenue Requirement Adjustments

In the Decision, the OEB approved Hydro One's Application for recovery of the forecasted 2020 revenue requirement subject to the following adjustments:

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[4] Hydro One's Reply Argument, page 213, Lines 16-17. Exhibit G, Tab 1, Schedule 1, page 1, Lines 12 - 13. Exhibit G, Tab 1, Schedule 1, page 3 Lines 14-17. Exhibit G, Tab 1, Schedule 2 page 1 Lines 22-27

[5] Relative to the rates revenue requirement reflected in Hydro One's June 19, 2019 blue page update

[6] Hydro One's Argument-in-Chief (pp. 111-112) explains that it presents a rates revenue requirement based on Undertaking J8.5 that reflects the OEB's updated cost of capital parameters that were issued October 31, 2019

- a capital expenditure reduction of $400 million over the three-year test period[7] consisting of a $390.0 million reduction in System Renewal, a $5.7 million reduction in System Service, and a $4.3 million reduction in General Plant;
- an OM&A reduction of $10.1 million in 2020;[8] and
- a capital expenditure reduction of $21.0 million in 2020[9] and an OM&A increase of $21.0 million in 2020 to reflect the Board's Decision that the non-service component of Hydro One's OPEB costs[10] may not be capitalized as a result of a new accounting standard under U.S. GAAP.[11]

2.2 Other Revenue Requirement Adjustments

In addition to the adjustments listed above, Hydro One has reflected the OEB's directions and findings in a number of other areas, as follows.

2.2.1 Deferral and Variance Accounts

The final balance proposed for disposition of the deferral and variance accounts has been recalculated to reflect the Decision and is described in Section 6 below. A final balance of $44.0 million is included for recovery over a three-year term which represents a change of approximately $23.5 million relative to the as-filed balance[12], primarily due to the inclusion of the 2018 audited balance for the OPEB Cost Deferral Account, as directed in the Decision.[13]

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[7] Decision, p. 3.
[8] Ibid.
[9] 2021 and 2022 capital is also adjusted as discussed below in section 3.2. OM&A beyond 2020 is escalated based on the approved CIR formulas as discussed under section 4
[10] Decision, p. 99.
[11] Financial Accounting Standards Board Compensation-Retirement Benefits (Topic 715) - ASU-2017-07, March 2017
[12] Exhibit H, Tab 1, Schedule 3, Table 1, p.2 of 2
[13] Decision, p. 165

2.2.2 Other Revenue

Hydro One's Other Revenues are comprised of: (i) external revenues, discussed below; and (ii) wholesale meter service revenues, funding for Low Voltage Switch Gear ("**LVSG**") credit and export transmission service revenues, discussed in Section 8.

External Revenue

The OEB approved Hydro One's external revenue forecasts for the test years for Station Maintenance, Engineering and Construction, and Other External Revenues, but increased the forecast for Secondary Land Use to the average of the last three years. This adjustment increased Hydro One's total external revenue by $5.6 million in 2020, $5.3 million in 2021, and $5.0 million in 2022, as seen in Table 1 below.[14]

Table 1 – External Revenues ($ millions)

	External revenues (As-Filed)			**External revenues (Decision)**		
	2020	**2021**	**2022**	**2020**	**2021**	**2022**
Secondary Land Use	$17.9	$18.2	$18.5	$23.5	$23.5	$23.5
Station Maintenance	$4.0	$4.0	$4.0	$4.0	$4.0	$4.0
Engineering & Construction	$0.3	$0.3	$0.3	$0.3	$0.3	$0.3
Other External Revenues	$9.2	$10.3	$9.4	$9.2	$10.3	$9.4
Total	**$31.4**	**$32.7**	**$32.2**	**$37.0**	**$38.1**[15]	**$37.2**

2.2.3 Productivity Factor and Incremental Capital Stretch Factor

The revenue requirement forecast for 2021 and 2022 is adjusted to reflect the OEB's Decision in respect of the Custom Revenue Cap Index ("**Custom RCI**") as follows:

i. a 0.30% productivity factor (X-factor) to be applied to capital and OM&A;

[14] Decision, p. 157
[15] Total external revenue for 2021 is $38.1 million as a result of increasing Secondary Land Use revenue by $5.3 million.

ii. a 0.15% incremental stretch factor on capital; and

iii. the removal of working capital from the calculation of the capital factor (a detailed calculation of which is provided at Exhibit 1.9 “Working Capital Adjustment”).[16]

The Custom RCI is provided below in Table 2. The Inflation Factor for 2021 and 2022 will be updated in future annual update applications. Consistent with the Decision, the capital and productivity factors for 2021 and 2022 will not be updated annually.[17]

Table 2 – Custom RCI by Component (%)

Custom Revenue Cap Index by Component (%)	**2021**	**2022**
Inflation Factor (I)	1.80	1.80
Productivity Factor (X)	0.30	0.30
Capital Factor (C)	2.88	2.70
Custom Revenue Cap Index Total (I-X+C)	**4.38**	**4.20**

2.2.4 Cost of Capital Update

The weighted average cost of long term debt rate has been updated to 4.42% to reflect actual debt issuances for 2019 and, as directed in the Decision[18] updated schedules at Exhibits 1.4, 1.4.1, and 1.4.2 are provided reflecting same.

2.3 Revenue Requirement Components

Exhibit 1.0 provides a detailed breakdown of Hydro One’s adjusted revenue requirement relative to the revenue requirements presented in the blue page update filed June 19, 2019 and undertaking response J-8.5 filed November 11, 2019. Table 3 below shows an

[16] Decision, p. 39
[17] Ibid
[18] Decision, pp. 148-149

updated Summary of Revenue Requirement Components in a format consistent with the evidence filed by Hydro One during the course of the proceeding.

Table 3 – Summary of Revenue Requirement Components ($ millions)

Line		Reference	2020	2021	2022
1	Rate Base	Exhibit 1.2	12,359.6	12,927.3	13,640.9
2	Return on Debt	Exhibit 1.4	319.8	334.5	353.0
3	Return on Equity	Exhibit 1.4	421.2	440.6	464.9
4	Depreciation	Exhibit 1.2	473.4	500.2	524.5
5	Income Taxes	Exhibit 1.5	30.1	40.9	39.7
6	Total Capital Related Revenue Requirement		1,244.6	1,316.2	1,382.1
7	Working Capital Related Revenue Requirement	Exhibit 1.9	2.6	2.8	2.9
8	Total Capital Related Revenue Requirement (excluding working capital component)		1,242.0	1,313.4	1,379.2
9	Less Productivity Factor (0.30%+0.15%)			(5.9)	(6.2)
10	Less Removing Working Capital from Capital Factor			(0.1)	(0.2)
11	**Total Capital Related Revenue Requirement**		**1,244.6**	**1,310.2**	**1,375.7**
12	OM&A[19]	Exhibit 1.1	385.0	390.8	396.7
13	**Total Revenue Requirement**		**1,629.6**	**1,701.0**	**1,772.4**
14	Increase in Capital Related Revenue Requirement			65.6	65.5
15	Increase in Capital Related Revenue Requirement as a percentage of Previous Year Total Revenue Requirement			4.02%	3.85%
16	Less Capital Related Revenue Requirement in I-X			1.15%	1.16%
17	**Capital Factor**			**2.88%**	**2.70%**

3 CAPITAL REDUCTION AND FORECASTED IN-SERVICE ADDITIONS

Hydro One's proposed capital expenditures of $3,864.7 million[20] for the 2020 to 2022 period are reduced to $3,397.5 million to reflect the OEB's capital reductions of: $390.0 million to System Renewal; $5.7 million to System Service; $4.3 million to General Plant;[21] and an additional $67.2 million[22] to reflect the removal from the capital forecast of the non-service component of OPEB costs.

[19] The OM&A (line 12) provided for each year in Table 3 is determined based on the 2020 OEB-approved OM&A (see Exhibit 1.1) increased by the Inflation Factor and reduced by the proposed Productivity Factor, for a total increase of 1.5% per annum.
[20] Exhibit J1.1
[21] Decision, p. 3
[22] Decision, p. 99

Table 4 below reflects the proposed capital spending forecast updated in accordance with the Decision, which directed Hydro One to propose a preliminary annual distribution of the capital reductions over the three-year term.

Table 4 – Proposed Capital Spending Summary ($ millions)

OEB-Cost Category	2020			2021			2022			Total DRO		
	As-Filed*	Reduction	OEB-Approved	As-Filed*	Reduction	OEB-Approved	As-Filed*	Reduction	OEB-Approved	Total As-Filed*	Total Reduction	Total Approved
System Access	24.8	0.0	24.8	11.3	0.0	11.3	11.7	0.0	11.7	47.8	0.0	47.8
System Renewal	865.2	(55.1)	810.1	1,103.1	(120.4)	982.8	1,172.8	(214.5)	958.2	3,141.1	(390.0)	2,751.1
System Service	204.1	(5.7)	198.4	148.2	0.0	148.2	151.8	0.0	151.8	504.1	(5.7)	498.4
General Plant	115.4	(4.3)	111.1	94.4	0.0	94.4	94.7	0.0	94.7	304.5	(4.3)	300.1
Total before adjustments	**1,209.5**	**(65.1)**	**1,144.4**	**1,357.0**	**(120.4)**	**1,236.6**	**1,431.0**	**(214.5)**	**1,216.5**	**3,997.5**	**(400.0)**	**3,597.5**
Directive	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.4)	0.0	(0.4)	(1.0)	0.0	(1.0)
Progressive Productivity	(17.0)	0.0	(17.0)	(39.0)	0.0	(39.0)	(61.0)	0.0	(61.0)	(117.0)	0.0	(117.0)
Pension Adjustment	(4.2)	0.0	(4.2)	(5.2)	0.0	(5.2)	(5.4)	0.0	(5.4)	(14.8)	0.0	(14.8)
Total after adjustments not including OPEB	**1,188.0**	**(65.1)**	**1,122.9**	**1,312.5**	**(120.4)**	**1,192.1**	**1,364.2**	**(214.5)**	**1,149.7**	**3,864.7**	**(400.0)**	**3,464.7**
OPEB Costs Moved to OM&A		(21.0)	(21.0)		(22.9)	(22.9)		(23.3)	(23.3)		(67.2)	(67.2)
Total (Removing OPEB)	**1,188.0**	**(86.1)**	**1,101.9**	**1,312.5**	**(143.3)**	**1,169.2**	**1,364.2**	**(237.8)**	**1,126.4**	**3,864.7**	**(467.2)**	**3,397.5**

**As-Filed reflects capital spending included in Exhibit J1.1*

3.1 Work Program Capital Reductions and Corresponding Rate Impacts

Of the $390 million capital reduction directed to be made to the System Renewal category:

- Hydro One applied $340 million to the Transmission Lines sub-category. Of this amount, $312 million was applied to overhead conductor replacement projects (SR-19 and SR-20) that are currently in the planning stage and not in execution.[23] The $28 million balance was applied to ancillary transmission line assets such as wood structure replacements and insulator replacements.[24] Sixty percent of overhead conductor replacement projects are in execution and were not cut, as cancelling these projects would result in significant inefficiencies, stranded costs and missed outcomes. Reductions were also not applied to overhead conductor replacement projects that are upstream of northern and First Nations communities, so Hydro One may address OEB direction from prior proceedings[25] in respect of the reliability to these communities. As conductors exist in the public domain, Hydro One was also cognizant of risks to public safety in respect of project changes when assessing how to apply capital reductions.
- A $50 million reduction was applied to the Transmission Stations sub-category based on Hydro One's risk-based prioritization framework, which considered system reliability, customer requirements and broader system planning considerations.

Hydro One applied a $5.7 million reduction to System Service and a $4.3 million reduction to General Plant.

[23] Exhibit ISD SR-19 and ISD SR-20
[24] Decision, p. 85
[25] OEB Decision and Order re Hydro One Networks Inc., Application for electricity distribution rates beginning January 1, 2018 until December 31, 2022, 2019, (EB-2017-0049), March 7, 2019, at p.18

In its Decision, the OEB applied capital reductions at the OEB-cost category level (e.g. System Access, System Service System Renewal, General Plant), rather than the total capital envelope. Hydro One notes the following implications associated with this approach:

- Costs in System Access are wholly driven by external requests from customers and government. If Hydro One receives additional customer or government requests and costs in this category increase, they may need to be funded through other OEB-cost categories.
- Costs in System Service are largely driven by provincial planning processes for bulk and regional systems to provide transmission access and additional capacity for new customer connections and to implement regional development plans that are jointly developed with customers, transmitters, distributors and the Independent Electricity System Operator ("**IESO**"). Depending on the output of the provincial planning processes to commence later this year, including ongoing Regional Planning and bulk system level studies, costs in this category could increase, and may need to be funded through other OEB-cost categories.
- If requirements or opportunities arise in any of the OEB-cost categories over the course of the rate period, and costs increase or decrease as a result, there will be fluctuations within or between costs categories.

3.2 Impact of Removal of Non-Service Component of OPEB Costs from Capital

Hydro One reduced the capital expenditures for 2020, 2021 and 2022 by $21.0 million, $22.9 million and $23.3 million, respectively, to reflect the fact that the non-service component of OPEB costs will no longer be capitalized and will instead be recovered through OM&A.[26]

[26] Decision, p. 99

As summarized during the proceeding, capital expenditure and in-service addition amounts presented in the Application were based on the assumption that Hydro One would be permitted to capitalize the non-service portion of OPEBs. As such, the non-service component of OPEB costs were included in the capital and in-service addition amounts. However, for the purposes of calculating revenue requirement and rate base, the non-service component of OPEB costs was excluded pending a decision on this point.[27]

The impact of the Decision regarding OPEBs on OM&A is discussed in section 4. The impact of the Decision regarding OPEBs on Tax is discussed in section 5.3. The disposition of the OPEB Cost Deferral Account is discussed in section 6.1.

The Board issued its Decision on the non-service component of OPEB costs for both the transmission and distribution segments of Hydro One. For its distribution business, Hydro One will continue to accumulate the non-service component of OPEB costs in the OPEB Cost Deferral Account that was established for the Distribution business until its next rebasing application, at which point a balance will be put forth for disposition.[28]

3.3 Impact of the Capital Reductions on In-Service Capital Additions

The total in-service additions amount of $3,613.0 million[29] requested in Hydro One's Application over the three-year period has been reduced to $3,249.0 million, to reflect the impact of the capital reductions described above.

Table 5 shows Hydro One's forecast of in-service capital additions over the three-year rate period.

[27] Exhibit F, Tab 5, Schedule 1, p. 10 of 11. See Undertaking J-6.04 for a description of the non-service component of OPEB costs for Transmission and Distribution
[28] Decision, p. 99.
[29] Exhibit J1.1

1 **Table 5 – Proposed In-Service Capital Additions Summary ($ millions)[30]**

	2020			2021			2022			Total DRO		
OEB-Cost Category	**As-Filed***	**Reduction**	**OEB-Approved**	**As-Filed***	**Reduction**	**OEB-Approved**	**As-Filed***	**Reduction**	**OEB-Approved**	**Total As-Filed***	**Total Reduction**	**Total OEB-Approved**
System Access	59.2	(50.6)	8.6	5.3	8.5	13.8	14.1	38.2	52.3	**78.6**	(3.9)	74.7
System Renewal	762.0	59.3	821.3	998.7	(262.8)	735.9	1,138.7	(107.7)	1,031.0	**2,899.4**	(311.2)	2,588.2
System Service	155.1	(100.9)	54.2	175.2	60.5	235.7	137.7	44.3	182.0	**468.0**	3.8	471.8
General Plant	76.9	(1.8)	75.1	155.1	(20.6)	134.5	59.5	23.0	82.5	**291.5**	0.6	292.1
Total before adjustments	**1,053.2**	**(94.0)**	**959.2**	**1,334.3**	**(214.5)**	**1,119.8**	**1,350.0**	**(2.3)**	**1,347.8**	**3,737.6**	**(310.8)**	**3.426.8**
Directive	(0.3)	0.0	(0.3)	(0.3)	0.0	(0.3)	(0.4)	0.0	(0.4)	**(1.0)**	0.0	**(1.0)**
Progressive Productivity	(15.8)	0.0	(15.8)	(36.3)	0.0	(36.3)	(56.7)	0.0	(56.7)	**(108.8)**	0.0	**(108.8)**
Pension Adjustment	(4.2)	0.0	(4.2)	(5.2)	0.0	(5.2)	(5.4)	0.0	(5.4)	**(14.8)**	0.0	**(14.8)**
Total after adjustments not including OPEB	**1,032.9**	**(94.0)**	**938.9**	**1,292.5**	**(214.5)**	**1,078.0**	**1,287.6**	**(2.3)**	**1,285.2**	**3,613.0**	**(310.8)**	**3,302.2**
Non-service components of OPEBs		(8.4)	(8.4)		(21.8)	(21.8)		(23.1)	(23.1)		(53.2)	(53.2)
Total (Removing OPEB)	**1,032.9**	**(102.4)**	**930.5**	**1,292.5**	**(236.3)**	**1,056.2**	**1,287.6**	**(25.4)**	**1,262.2**	**3,613.0**	**(364.0)**	**3,249.0**

*As-Filed reflects in-service additions included in Exhibit J1.1

[30] Exhibit J1.1

Variances between As-Filed and DRO ISAs

In the Application, Hydro One forecasted that it would in-service $78.6 million in System Access investments over the three-year rate period. In this DRO, Hydro One forecasts that it will in-service $74.7 million, for a variance of $3.9 million. This variance is attributable to project timing, including projects such as construction of Leamington DESN 2 which was advanced into 2019 to meet customer needs, and construction of Seaton TS which was delayed to 2021 based on updated timing from the associated distributor.

In the Application, Hydro One forecasted that it would in-service $2,899.4 million in System Renewal investments over the three-year rate period. In this DRO, Hydro One forecasts that it will in-service $2,588.2 million, for a variance of $311.2 million. This variance is attributable to reductions from the overhead line and component replacement portfolio.

In the Application, Hydro One forecasted that it would in-service $468.0 million in System Service investments over the three-year rate period. In this DRO, Hydro One forecasts that it will in-service $471.8 million, for a variance of $3.8 million. This variance is attributable to project timing, with capital expenditures from the prior rate period being in-serviced in the current rate period, offset by the capital disallowance of $5.7 million. Timing impacts include project delays due to third-party schedules (connection of the Wataynikaneyap Line at Pickle Lake, SS-02) and coordination with distributors which delayed OEB approvals (Barrie Area Transmission Upgrade, SS-09).

In the Application, Hydro One forecasted that it would in-service $291.5 million in General Plant investments over the three-year rate period. In this DRO, Hydro One forecasts that it will in-service $292.1 million, for a variance of $0.6 million, with capital expenditures from the prior rate period being in-serviced in the current rate period, offset by the capital disallowance of $4.3 million. This variance is attributable to project timing.

Figure 1 below illustrates when Hydro One anticipates its capital investments in 2020 to 2022 will be put into service. The practical reality of managing a large capital portfolio is that projects can take many years or months to complete, circumstances may change throughout the course of the project and plans must adapt accordingly. As a consequence, in-service additions generally lag behind capital expenditures. See Figure 2.

Unlike Distribution, which is largely programmatic investments where a substantial proportion of in-year capital expenditures are in-serviced in-year, the Transmission business consists of multi-year projects, where, on average, only about 40% of the in-year capital contributes to in-service additions in the same year. This, however, is dependent upon the nature of investments within the portfolio, and the associated execution plans, which in-turn are dependent upon the IESO and customer outage constraints.

Figures 1 and 2 below illustrate the approximate timing of in-year capital expenditures; for example, the 2020 expenditures are largely in-serviced over the 2020-22 period, with 37% or $406 million, of expenditures in-serviced in 2020, 52% or $576 million in-serviced in 2021, and the remaining 11% or $120 million in-serviced in 2022. As in-service additions lag behind capital expenditures, approximately 34% of 2021 and 2022 capital expenditures will be in-serviced beyond the test years.

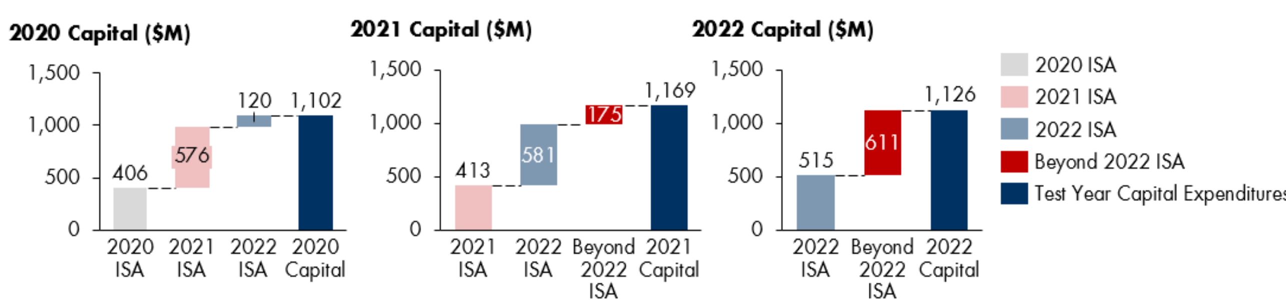

Figure 1: Timing of In-Service of Test Year Capital Expenditures

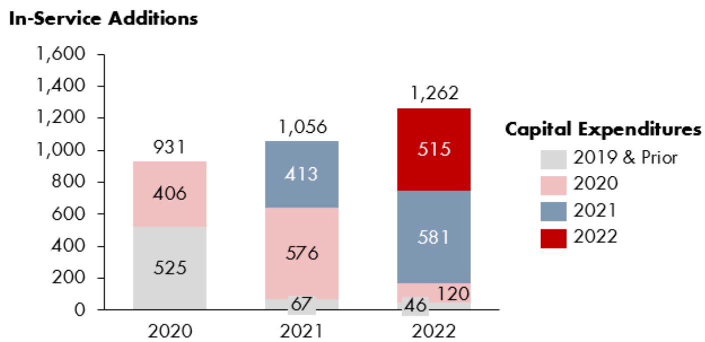

Figure 2: Capital Expenditure Contribution to Test Year In-Service Additions

4 OM&A

The Decision impacted Hydro One's proposed OM&A expenses in two respects, as follows and as further detailed in Table 6 below:

- First, the OEB imposed an overall reduction of $10.1 million[31] to Hydro One's proposed 2020 OM&A expenditures of $374.1 million.[32]
- Second, the OEB found that the non-service component of Hydro One's OPEB costs shall be recognized as OM&A rather than capital.[33]

OM&A for 2021 and 2022 will be calculated using the Custom RCI formula based on the 2020 OM&A amount adjusted to reflect the Decision. Accordingly, that amount will be increased by the approved inflation factor issued annually by the OEB and reduced by the productivity factor as further presented under section 2.2.3.

[31] Decision, p. 3
[32] Exhibit J1.1
[33] Decision, p. 99

Table 6 – Summary of Recoverable OM&A Expenses ($ millions)

Description	2020
Sustainment	214.2
Development	6.9
Operations	48.9
Customer Care	7.5
Common Corporate Costs & Other	30.3
Property Taxes & Rights Payments	68.1
Directive	(0.1)
Total Transmission OM&A	**375.8**
Pension Adjustment to Dec. 31, 2018 Valuation	(1.7)
Updated Total Transmission OM&A	**374.1**
OEB Decision Adjustments	
Overall OM&A Reduction	(10.1)
Non-Service Component of OPEB	21.0
Total Decision Adjustments	**10.9**
Total	**385.0**

5 TAX CONSIDERATIONS

The regulatory income tax being recovered as part of the revenue requirement is net of allocated tax savings to ratepayers that arose from Hydro One's departure from the Payments in Lieu of Corporate Income Taxes ("**PILs**") regime (also known as "**Deferred Tax Asset Sharing**"), incorporates the Accelerated Investment Incentive impact, and reflects the impact of the OEB's Decision.

5.1 Detailed Tax Schedules

The OEB directed Hydro One to provide an updated set of detailed regulatory tax calculations that underpin the regulatory income tax expense amounts.[34] The detailed calculations are provided in Exhibit 1.5, 1.5.1 and 1.5.2.

[34] Decision, p. 117.

5.2 Accelerated Investment Incentive ("Accelerated CCA")

In the Decision, the OEB directed Hydro One to: (i) review its calculation of the revenue requirement impact of the Accelerated CCA and to confirm that no further changes are required;[35] and (ii) record the impact of the Accelerated CCA program for 2018 and 2019 in the new sub-account 1592.[36]

Hydro One incorporated the regulatory tax reduction relating to the Accelerated CCA in the income tax amounts to be included in the revenue requirement, which has been updated to reflect the OEB's reduction to Hydro One's capital program. Hydro One confirms the updated calculation appropriately reflects the impact of the Accelerated CCA.

The impact of the Accelerated CCA for 2018 and 2019 in the amount of $20.2 million is recorded in the new sub-account 1592.

5.3 Impact of the Decision on Regulatory Tax

As noted in earlier sections of this DRO, the Decision reduced Hydro One's proposed capital expenditures by $400 million[37] and removed the non-service component of OPEB costs from capital, which are instead recognized as OM&A expenses. The Decision impact on income taxes was $12.1 million, $22.4 million and $8.5 million in each of 2020, 2021 and 2022. The contributing factors to these tax impacts were as follows:

Capital expenditure reduction: The OEB's reduction in respect of the proposed capital program reduced Hydro One's capital asset additions for tax purposes. This has the effect

[35] Decision, p. 117.
[36] Decision, p. 117.
[37] Decision, p. 3.

of reducing the annual capital cost allowance deductions available to Hydro One, thereby increasing Hydro One's regulatory tax expense (as compared to what Hydro One previously forecast). The impact to regulatory taxes directly correlates with the quantum of in-service capital additions. As such, compared to what Hydro One previously proposed, regulatory taxes will be higher overall, and more so in years with a greater reduction to in-service additions, and the impact is magnified due to the Accelerated CCA treatment. In light of the proposed in-service capital additions in Table 5, the total tax impact to revenue requirement is an increase in regulatory tax of $1.7 million, $14.0 million and $1.2 million for 2020, 2021 and 2022 respectively.

Non-service component of OPEB costs: For financial reporting purposes, OPEB related costs are recognized as expenditures when accrued. However, for tax purposes, OPEB related costs are recognized as deductions when payments are made. The timing difference results in higher regulatory taxable income and income tax thereon. The foregoing tax treatment is in accordance with the Income Tax Act[38] and is consistent with the treatment of such costs in Hydro One's prior Transmission revenue requirement application (EB-2016-0160).[39] The total tax impact to revenue requirement as a result of removing the non-service component of OPEB costs from capital and recognizing this component as an OM&A expense (including the disbursal of the OPEB Cost Deferral Account) is an increase in regulatory tax of $10.3 million, $10.4 million and $10.5 million for 2020, 2021 and 2022 respectively.

The foregoing amounts are partially offset by lower taxes arising from lower return on equity.

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[38] Income Tax Act, paragraph 18 (1) (e)
[39] EB-2016-0160, Exhibit C2, Tab 4, Schedule 1, Attachment 1, Line 3: "Calculation of Utility Income Taxes, Other Post Employment Benefits expense"

6 DEFERRAL AND VARIANCE ACCOUNTS

Section 6.1 describes the OEB-approved disposition of existing deferral and variance accounts. Sections 6.2 to 6.4 describe the accounts that are subject to specific OEB directions in the Decision. Section 6.5 describes Hydro One's request for a further modification to the CISVA that was approved in the Decision. Section 6.6 sets out Hydro One's request for the Foregone Revenue Transmission Deferral Account.

6.1 Disposition of Accounts

The OEB approved the disposition of Hydro One's deferral and variance account balances (December 31, 2018 audited balances) including interest to December 31, 2019 and adjusted for dispositions approved by the OEB during 2019, as presented in the Application.[40] Furthermore, the OEB directed Hydro One to include in the balance for disposition the 2018 audited balance for the OPEB Cost Deferral Account, which was previously excluded from the total disposition amount.[41] After a further adjustment to incorporate interest to June 30, 2020 as directed in the Decision, the final disposition is calculated to be $44.0 million,[42] as summarized in Table 7 below. This balance is to be included as an adjustment to the revenue requirement over a three-year period commencing with the 2020 test year, as presented further in Exhibit 1.0.

[40] Decision, p. 164
[41] Decision, p. 165
[42] Decision, p. 164

Table 7 – Disposition of Deferral and Variance Accounts ($ millions)[43]

Description	Account Balance As Filed (Interest and Principal)	Account Balance per Decision (Interest and Principal)
Excess Export Service Revenue	4.8	4.8
External Secondary Land Use Revenue	(10.4)	(10.5)
External Stations Maintenance, E&CS & Other External Revenue	4.5	4.6
Tax Rate Changes	0.0	0.0
Rights Payments	2.4	2.4
Pension Costs Differential	(4.5)	(4.5)
Long-Term Transmission Future Corridor Acquisition and Development	0.0	0.0
LDC CDM and Demand Response Variance Account	23.6	23.9
External Revenue – Partnership Transmission Projects Account	(0.0)	(0.0)
OEB Cost Differential Account	(0.1)	(0.1)
Waasigan Transmission Line Deferral (Formerly NWBTL)	0.9	0.9
In-Service Capital Additions Variance	(0.6)	(0.7)
OPEB Cost Deferral Account	-[1]	23.2
Total Regulatory Accounts for Disposition	**20.5**	**44.0**

1: Not previously requested for disposition

6.2 Integrated System Operating Center (ISOC) Asymmetrical Variance Account

Hydro One will establish an asymmetrical variance account for the ISOC as directed by the OEB, to track actual costs that are less than the estimated total project costs.[44] If the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One will return the difference to ratepayers. The balance captured in the ISOC variance account shall be adjusted from the calculation of the Transmission Capital In-Service Additions variance account to ensure the revenue requirement impact

[43] Format consistent with Exhibit H-1-3, Table 1

is only captured in one of the accounts. The draft accounting order is provided in Exhibit 3.0.

6.3 Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account

The OEB approved Hydro One's proposal to establish an asymmetrical cumulative variance account to record differences between the asset removal cost forecasts that have been included in the proposed depreciation expenses for 2020 to 2022 based on the updated planning assumptions and the actual asset removal costs incurred in each of the test years.[45] The draft accounting order is provided in Exhibit 3.1.

6.4 Local Distribution Company Conservation Demand Management and Demand Response Variance Account

The Local Distribution Company ("**LDC**") Conservation Demand Management ("**CDM**") and Demand Response Variance Account was ordered closed effective January 1, 2020.[46] Variances for 2018 and 2019 will be recorded in the existing account once the required information becomes available and Hydro One will seek disposition of the balance of this account in a future rebasing application.

6.5 CISVA Account

The CISVA tracks the revenue requirement associated with the difference between:

- actual ISAs; and
- OEB-approved ISAs.

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[44] Decision, p. 86
[45] Decision, p. 119
[46] Decision, p. 165

The CISVA is asymmetrical to the benefit of ratepayers such that, if actual ISAs are 98% or lower than OEB-approved ISAs in any given year of the Custom IR term, the revenue requirement impact associated with the shortfall is entered into the account for that year and will be returned to customers at the next rebasing application.

In the Decision, the OEB approved a modification[47] to the calculation from the previously approved version of this account (from the 2017-2018 Transmission revenue requirement proceeding)[48] to exclude any verifiable productivity savings from the calculation of the balance that flows to the account in order to ensure that true productivity savings are incented throughout the term of the Custom IR Application. The OEB also approved a 2% dead band on the calculation.[49]

In consideration of the potential future impacts and uncertainties of COVID-19 on Hydro One's work-plan, such as a potential second wave of COVID-19, IESO outage restrictions to minimize the risk of forced outages, evolving impacts on customers, supply chain issues, and approval delays arising from restrictions on public consultations/gatherings, Hydro One proposes a further modification to the CISVA. This modification would permit Hydro One to put in-place recovery plans to return to plan in a subsequent year, as further described below, thereby recognizing that in the foregoing circumstance, the variation of ISAs is outside Hydro One's control and not a consequence of any deficiencies in the company's ability to plan and implement ISAs.

[47] Decision, p. 172-173
[48] EB-2016-0160 Decision and Order, p. 73-75
[49] Decision, p. 172-173

Currently Approved CISVA

The currently approved annual calculation takes into consideration ISAs for the current year added together with the ISAs for all prior years in the Custom IR term, as follows[50]:

- 2020 variance: (Approved 2020 ISAs) – (verifiable productivity savings) – (Actual 2020 ISAs)
- 2021 variance: (Approved 2020 ISAs + Approved 2021 ISAs) – (verifiable productivity savings) – (Actual 2020 ISAs + Actual 2021 ISAs)
- 2022 variance: (Approved 2020 ISAs + Approved 2021 ISAs + Approved 2022 ISAs) – (verifiable productivity savings) – (Actual 2020 ISAs + Actual 2021 ISAs + Actual 2022 ISAs)

If there is a 2% or more variance in any year in the Custom IR term, the associated revenue requirement impact is to be returned to ratepayers following the next rebasing application. Under the current calculation, if there is shortfall of 2% or more in 2020, an amount will be booked in 2020 to be returned to ratepayers and, in 2021, the company must make up the shortfall to come within the 2% threshold or yet another amount would be booked to the account for 2021.

Proposed Modification to the CISVA

Relative to the established CISVA calculation described above, as approved in the Decision, Hydro One requests a further modification to address the potential future impacts of COVID-19 on Hydro One's work-plan.

The requested modification would allow Hydro One, in 2021, to 'catch-up' on any work that it has planned for 2020 but which is not completed during 2020 as a result of the COVID-19 pandemic. With this modification, Hydro One would not perform the calculation for 2020. In performing the calculation for 2021, Hydro One would

[50] Note, 2019 will be included in this calculation as confirmed in response to IR OEB 224.

determine the entry in the account on the basis of a cumulative view of ISAs in 2020 and 2021. Hydro One remains committed to achieving its planned outcomes over this period, with a return to the normal methodology for 2022 (subject to the further request below) as follows:[51]

- 2020 and 2021 variance[52]: (Approved 2020 ISAs + Approved 2021 ISAs) – (verifiable productivity savings) – (Actual 2020 ISAs + Actual 2021 ISAs)
- 2022 variance: (Approved 2020 ISAs + Approved 2021 ISAs + Approved 2022 ISAs) – (verifiable productivity savings) – (Actual 2020 ISAs + Actual 2021 ISAs + Actual 2022 ISAs)

Therefore, with the proposed modification if there is shortfall of 2% or more in 2020, Hydro One will have an opportunity to catch up on its ISAs in 2021 without booking an amount to the CISVA for 2020. This would provide Hydro One with a one-year opportunity to make up for planned 2020 in-service additions that are not able to be placed into service in 2020 due the COVID-19 pandemic. While the CISVA is intended to protect customers from potential underspending on Hydro One's capital plan that may occur in the normal course, it is not intended to be punitive to Hydro One for delayed capital investments and the associated ISAs due to unprecedented and unforeseeable circumstances beyond Hydro One's control such as COVID-19. The proposed modification would provide appropriate flexibility and not detract from the underlying objective of the account. Hydro One remains committed to driving the right behaviors and achieving its planned outcomes over this period, in a safe manner.

As part of its 2022 Annual Update, Hydro One proposes to advise the OEB whether its planned ISAs for 2020 and 2021 have been materially impacted by the COVID-19 pandemic, and that it be provided with an opportunity at that time to request that the relief above be extended to 2022, which would give Hydro One the opportunity to catch

[51] Note, 2019 will be included in this calculation as confirmed in response to IR OEB 224.
[52] Calculated to arrive at 2021 variance.

up on its 2020 and 2021 in-service additions in 2022 without booking an amount to the CISVA for 2020 or 2021. Alternatively, the OEB could extend the modification requested above to 2022 with the proviso that in the event that COVID-19 impacts continued to be an issue in 2021, Hydro One could elect to attempt to catch-up in 2022 and treat the CISVA account as cumulative in respect of in-service additions in 2020, 2021, and 2022.

An updated accounting order, reflecting the proposed modification to the CISVA is provided in Exhibit 3.2.

6.6 Foregone Transmission Revenue Deferral Account

In section 8.8, below, Hydro One describes several alternatives that are available to the OEB when it implements UTRs, after the final rate order is issued in the current proceeding. In the event that the OEB ultimately chooses to proceed with any of the alternatives, Hydro One would require a Foregone Transmission Revenue Deferral Account. Hydro One therefore re-submits for the OEB's approval its request for the Foregone Transmission Revenue Deferral Account. As indicated in the proposed accounting order provided in Exhibit 3.3, the deferral account is proposed to be subject to interest improvement.

7 TRANSMISSION SCORECARD

In the Decision, the OEB approved Hydro One's proposed Transmission scorecard, with the addition of a metric to measure the accomplishment of the System Renewal program at the portfolio level, to demonstrate the degree to which Hydro One is able to complete its planned program within the approved budget for this work category. The Decision noted that the Capital Program Accomplishment (composite index) ("**CPAI**") measure only covered six programs under the System Renewal budget and found that it would be beneficial to add one more metric which measures the System Renewal program accomplishment, at the portfolio level, for the remainder of the System Renewal program.[53]

In addressing the OEB's Decision and the concern regarding the composition of the CPAI measure, Hydro One has revised the existing CPAI measure to include an additional eleven components from the System Renewal category and revised the name to the Transmission Capital Accomplishment Index ("**TCAI**"). Table 8 below provides a comparison of the composition of the CPAI and the TCAI measures.

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[53] Decision, p. 56.

Table 8 – CPAI and TCAI Measure Composition

No.	CPAI Composition As-Filed[54]	TCAI Composition
1	SR-09 – Purchase of Spare Transformers Program[55]	SR-01 – Air Blast Circuit Breaker Replacement Project
2	SR-21 – Tx Wood Pole Replacement Program	SR-02 – Station Reinvestment Project
3	SR-22 – Steel Structure Coating Program	SR-03 – Bulk Station Transformer Replacement Project
4	SR-23 – Tx Lines Foundation Assess/Clean/Coat Program	SR-04 – Bulk Station Switchgear and Ancillary Equipment Replacement Project
5	SR-24 – Shieldwire Replacement Program	SR-05 – Load Station Transformer Replacement Project
6	SR-25 – Tx Lines Insulator Replacement Program	SR-06 – Load Station Switchgear and Ancillary Equipment Replacement Project
7		SR-07 – Protection and Automation Replacement Project
8		SR-08 – John Transformer Station Reinvestment Project
9		SR-09 – Purchase of Spare Transformers Program
10		SR-19 – Transmission Line Refurbishment - End of Life ACSR, Copper Conductors & Structures Project
11		SR-20 – Transmission Line Refurbishment - Near End of Life ACSR Conductor Project
12		SR-21 – Tx Wood Pole Replacement Program
13		SR-22 – Steel Structure Coating Program
14		SR-23 – Tx Lines Foundation Assess/Clean/Coat Program
15		SR-24 – Shieldwire Replacement Program
16		SR-25 – Tx Lines Insulator Replacement Program
17		SR-27 – C5E/C7E Underground Cable Replacement Project

As a result of the Decision, the System Renewal category will represent 79% of the total approved capital budget over the 2020-2022 application term; the proposed TCAI

[54] Exhibit J1.2.
[55] The Purchase of Spare Transformers Program is a component of the total SR-09 Transmission Station Demand and Spares and Targeted Assets Program.

measure represents 81% of the OEB-approved System Renewal program over the application term. The CPAI measure, as originally proposed, represented approximately 13% of the total proposed capital portfolio, whereas the enhanced TCAI metric covers approximately 64% of the approved capital portfolio over the test years.

The TCAI composite index measure compares the weighted actual in-year accomplishment for significant Transmission Capital investments against the weighted budget. The programs monitored for this measure include the Steel Structure Coating Program, Transmission Lines Insulator Replacement Program, Transmission Wood Pole Replacement, Tower Foundation Refurbishment, Shieldwire Replacement, Purchase of Station Spare Transformers, Air Blast Circuit Breaker Replacement projects, Station Reinvestment projects, Bulk Station Transformer projects, Bulk Station Switchgear and Ancillary Equipment Replacement projects, Load Station Transformer replacement projects, Load Station Switchgear and Ancillary Equipment Replacement projects, Protection and Automation replacement projects, and Transmission Line refurbishment projects.

The revised metric now includes programmatic component replacements, including poles, towers, foundations, shieldwire and insulators as well as project based components such as conductors, breakers, transformers and protections. This metric is one element which can demonstrate the degree to which Hydro One is able to complete the planned capital program within the approved budget for the System Renewal category. The TCAI measure is meant to be evaluated in the context of other measures presented in Transmission scorecard, the capital program performance report, and with the understanding that the measure itself is a blend of programs and projects.

The methodology for the calculation of the TCAI measure is consistent with the calculation for the CPAI measure as described in Exhibit J1.2, and reproduced below in Table 9 along with a formula showing the calculation of the measure.

Table 9 – TCAI Calculation Methodology

Investment (n)	Budget	Budget Weighting (n)	Units Planned	Units Installed	Completion	Weighted Index (n)
SR – (n)	A	C = A/B	D	E	F = E/D	C x F
Total Budget	**B**					

$$TCAI = \frac{\sum^{n} Weighting\ Index\ (n)}{\sum^{n} Budget\ Weighting\ (n)} \times 100\%$$

8 RATES

8.1 Load Forecast

The OEB approved Hydro One's 2020 load forecast as filed in the Application but fixed the 2021 and 2022 forecasts for embedded generation and CDM at the 2020 forecast levels.[56] The resulting forecast for Ontario demand for each of the test years is presented below in Table 10.

Table 10 – Approved 2020-2022 Ontario Demand

Forecast Year	Ontario Demand (MW)
2020	19,586
2021	19,557
2022	19,544

The charge determinants for the Network, Line Connection and Transformation Connection rate pools based on this updated forecast of Ontario demand are provided in Exhibit 2.0.[57]

[56] Decision, p. 153.
[57] Exhibit 2.0 provides an updated version of Hydro One's pre-filed evidence exhibit E-03-01, Table 3.

8.2 Rates Revenue Requirement and Charge Determinants by Rate Pool

The OEB approved Hydro One's methodology for allocating the transmission rates revenue requirement into rate pools[58] and Hydro One has used this methodology to perform the allocation by rate pools, as provided in the following exhibits:

- Exhibit 2.1: 2020 – 2022 charge determinants by rate pool;
- Exhibit 2.2: 2020 – 2022 Rates Revenue Requirement by rate pool (not including foregone revenue); and
- Exhibit 2.4: 2020 Rates Revenue Requirement by rate pool (including foregone revenue).

As proposed by Hydro One and accepted by the OEB,[59] Hydro One will not re-run the cost allocation model over the term of the plan.

8.3 Wholesale Meter Service

Wholesale Meter Service revenues of $0.1 million in each year were approved as filed.[60] See Exhibit 2.9 for the Wholesale Meter Service and Exit Fee Schedule.

8.4 Low Voltage Switchgear Credit

The amount of the Low Voltage Switchgear ("**LVSG**") Credit has been calculated in accordance with the methodology approved by the OEB. The derivation of the 2020 LVSG amount of $14.4 million, as well as estimates of the 2021 and 2022 LVSG amounts, are shown in Exhibit 2.7. These amounts are included in the derivation of Hydro One's rates revenue requirement used for setting UTRs.

[58] Decision, p. 175.
[59] Decision, pp. 173; 175.
[60] Decision, p. 158.

8.5 Export Transmission Service

The OEB approved the Export Transmission Service ("**ETS**") Revenue based on the proposed rate of $1.85 per MWh, resulting in approved ETS revenue of $35.9 million in each of 2020 and 2021 and $36.3 million in 2022, as shown in Exhibit 1.7.[61] These amounts are included in the derivation of Hydro One's rates revenue requirement used for setting UTRs.

8.6 Foregone Revenue Calculation

In the Decision, the Board approved Hydro One's revenue requirement effective January 1, 2020, and indicated that it expects to implement updated UTRs on July 1, 2020.[62] The foregone revenue for the six-month period between January 1, 2020 and June 30, 2020 is $28.1 million. The calculation of foregone revenue follows the methodology previously approved by the OEB, most recently in EB-2018-0130. The 2020 foregone revenue calculation details and the annualized foregone revenue amount that would need to be included in the derivation of the 2020 UTR to be implemented on July 1, 2020 are provided in Exhibit 2.3.1 to 2.3.3.

8.7 UTR Schedules and Disbursement Allocators

The current (interim) UTRs and disbursement allocators, as well as UTR schedules are provided in Exhibits 2.5.1 and 2.5.2, respectively.

The UTRs and disbursement allocators and UTR schedules, reflecting a July 1, 2020 implementation of the approved changes to revenue requirement and charge determinants for Hydro One Networks, are provided in Exhibits 2.6.1 and 2.6.2, respectively.

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[61] Decision, p. 158.
[62] Decision, p. 20.

8.8 Implementation Alternatives for Consideration in UTR Proceeding

Regarding the OEB's plans for updating the UTRs, the Decision states:

> The severity and duration of the current COVID-19 emergency, which has occurred after the close of the record in this proceeding, and its impact on electricity utilities (i.e., transmitters) and customers alike, is uncertain. At this time, the OEB does not expect that the pandemic will impact the implementation of the Decision and Order, or its ability to update UTRs to be effective July 1, 2020, but the OEB will continue to closely monitor this situation [emphasis added].[63]

Should the Board choose to update the UTRs effective July 1, 2020, directly-connected transmission customers[64] such as LDCs and industrial customers will experience the effects of a rate increase due to the re-set of Hydro One's revenue requirement and charge determinants reflecting the OEB-approved load forecast.[65] Given the language in the Decision in relation to COVID-19 and UTR implementation (reproduced above) and the Board's approach of inviting alternative proposals on the implementation of a rate rider in Enbridge Gas Inc.'s recent rates proceeding,[66] Hydro One has identified three alternatives for the OEB to consider at such time that it carries out its process, following completion of the current proceeding, for updating the UTRs for all transmitters in Ontario, as follows:

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[63] Decision, p. 5
[64] Distribution customers will not experience a rate increase until either January or May 2021, depending on when LDCs re-set their rates to reflect the pass through of updated transmission rates.
[65] Directly-connected customers are currently paying interim rates which are based on the 2019 revenue requirement. This amount is higher than 2020 revenue requirement. Thus, the reason for the rate increase is re-set of the load forecast.
[66] EB-2019-0194, Decision and Order dated May 14, 2020 in respect of Enbridge Gas Inc.'s application for 2020 rates, at page. 25, where the OEB invited Enbridge to make alternative proposals on the implementation of the rate rider.

Decision: Implement Hydro One's approved 2020 revenue requirement and charge determinants in update to UTRs on July 1, 2020 and collect Hydro One's January to June 2020 Foregone Revenue of $28.1 million starting July 1, 2020 over the balance of 2020 (6 months).[67]

Alternative 1: Implement Hydro One's approved 2020 revenue requirement and charge determinants in update to UTRs on July 1, 2020 but *defer* collection of Hydro One's January to June 2020 Foregone Revenue of $28.1 million[68] to January 1, 2021 *over a period of one year*.

Alternative 2: Maintain interim UTRs to the end of 2020. On January 1, 2021 implement UTRs for 2021 to reflect Hydro One's approved 2021 revenue requirement, the approved charge determinants, and collect Hydro One's January to December 2020 Foregone Revenue of $57.1 million[69] *over a period of one year*.

Alternative 3: Maintain interim UTRs to the end of 2020. On January 1, 2021 implement UTRs for 2021 to reflect Hydro One's approved 2021 revenue requirement, the approved charge determinants, and collect Hydro One's January to December 2020 Foregone Revenue of $57.1 million[70] *over a period of two years*.

The estimated impact on UTRs and average customer bills for each of the Decision and the three alternatives set out above are detailed in Table 11.

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[67] Decision, p. 20
[68] This amount is the January to June foregone revenue amount shown in Exhibit 2.3.2, and would be subject to interest improvement.
[69] This amount is the January to December foregone revenue amount shown in Exhibit 2.3.2, and would be subject to interest improvement.
[70] This amount is the January to December foregone revenue amount shown in Exhibit 2.3.2, and would be subject to interest improvement.

Table 11 – Implementation Options and Estimated Impact on Transmission Rates and Average Bills

	July 1, 2020 Impacts	Jan. 1, 2021 Impacts	Jan. 1, 2022 Impacts
Decision			
Tx rate increase	*7.0%*	*1.1%*	*4.4%*
Tx Customer bill impact	0.5%	0.1%	0.3%
Dx Customer bill impact	0.0%	0.5%	0.3%
Alternative 1			
Tx rate increase	3.5%	6.4%	2.7%
Tx Customer bill impact	0.3%	0.5%	0.2%
Dx Customer bill impact	0.0%	0.6%	0.2%
Alternative 2			
Tx rate increase	0.0%	11.7%	1.0%
Tx Customer bill impact	0.0%	0.9%	0.1%
Dx Customer bill impact	0.0%	0.7%	0.1%
Alternative 3			
Tx rate increase	0.0%	9.9%	4.4%
Tx Customer bill impact	0.0%	0.7%	0.3%
Dx Customer bill impact	0.0%	0.6%	0.3%

In order to capture the impacts that customers would actually see as a result of any changes to UTRs, the transmission rate impacts shown above are relative to the currently approved interim UTRs.[71] The impacts indicated above also assume, as contemplated in the Decision[72], that any UTR changes made in July 2020 would not impact distribution customers until 2021, at which time distributors would be able to update their Retail Transmission Service Rates ("**RTSR**") to reflect the changes to transmission rates.

While the implementation of UTRs is a matter considered outside of the current proceeding and this DRO, Hydro One's intention is to provide the above information to assist the Board in its determination of whether an alternative UTR implementation date

[71] These impacts are different from the impacts shown in Exhibit 2.8 of this DRO, which are based on how bill impacts were calculated and presented in the Application (i.e. annual impacts relative to 2019 approved amounts).
[72] Decision, p. 5.

would help support Ontario electricity customers and LDCs experiencing liquidity concerns during this difficult time.

Hydro One's preference for implementing changes to UTRs is to adopt **Alternative 3**. This alternative would eliminate any transmission-related increases for both transmission and distribution customers in 2020, just as individuals and business are starting to recover from the effects of COVID-19 restrictions. Alternative 3 is also preferred as it mitigates the impacts on customers by spreading the subsequent recovery of foregone revenue over the remaining two-year period covered by the Application.

8.9 Bill Impacts

A summary of the updated 2020, 2021, and 2022 total bill impacts, consistent with the manner in which bill impacts were calculated and presented in the Application (i.e. annual impacts relative to 2019) is presented in Table 12.

Table 12 – Average Bill Impacts[73] on Transmission and Distribution-Connected Customers

		2020		2021		2022	
	2019[1]	**Blue page Update**	**OEB Decision**	**Blue page Update**	**OEB Decision**	**Blue page Update**	**OEB Decision**
Rates Revenue Requirement ($M)	**$1,552.3**	**$1,628.0**	**$1,585.8**	**$1,719.4**	**$1,656.6**	**$1,808.4**	**$1,729.1**
% Increase in Rates RR over prior year		4.9%	2.2%	5.6%	4.5%	5.2%	4.4%
% Impact of load forecast change		3.8%	3.8%	0.6%	0.2%	0.7%	0.1%
Net Impact on Average Transmission Rates		**8.7%**	**6.0%**	**6.2%**	**4.6%**	**5.9%**	**4.4%**
Transmission as a % of Tx-connected customer's Total Bill		*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*	*7.4%*
Estimated Average Tx Bill impact		**0.6%**	**0.4%**	**0.5%**	**0.3%**	**0.4%**	**0.3%**
Transmission as a % of Dx-connected customer's Total Bill		*6.2%*	*6.2%*	*6.2%*	*6.2%*	*6.2%*	*6.2%*
Estimated Average Dx Bill impact		**0.5%**	**0.4%**	**0.4%**	**0.3%**	**0.4%**	**0.3%**

1 2019 rates revenue requirement as per the OEB's Decision and Order for Hydro One's 2019 Transmission Revenue Requirement application (EB-2018-0130), issued on 25th April, 2019.

The impact on the 2020 monthly bill of a typical distribution residential customer consuming 750 kWh is estimated to be $0.54, and on a typical general service energy customer consuming 2,000 kWh is estimated to be $1.28. Details of the estimated bill impacts on residential and general service energy customers for all years, and for various consumption levels, are provided in Exhibit 2.8.

[73] Consistent with the approach taken in Exhibits J1.1 and J8.5, bill impacts are shown relative to Hydro One's updated evidence filed in the June 19, 2019 blue-page update.

9 SUPPORTING MATERIAL

Detailed supporting information for this DRO is provided in the following Exhibits.

Tab 1

- Exhibit 1.0 – Revenue Requirement Summary
- Exhibit 1.1 – OM&A
- Exhibit 1.2 – Rate Base and Depreciation
- Exhibit 1.3 – Capital Expenditures
- Exhibit 1.4 – Capital Structure and Return on Capital
  - Exhibit 1.4.1 Cost of Long Term Debt Capital, 2020
  - Exhibit 1.4.2 Cost of Long Term Debt Capital, 2020 AIC
- Exhibit 1.5 – Income Tax
  - Exhibit 1.5.1 Calculation of Utility Income Taxes
  - Exhibit 1.5.2 Calculation of Capital Cost Allowance (CCA)
- Exhibit 1.6 – External Revenue
- Exhibit 1.7 – Export Transmission Service Revenue
- Exhibit 1.8 – Deferral and Variance Account Balances
- Exhibit 1.9 – Working Capital Adjustment

Tab 2

- Exhibit 2.0 – Updated Exhibit E-03-01, Table 3: Impact of Embedded Generation and CDM on Charge Determinants by rate pool
- Exhibit 2.1 – 2020 to 2022 Charge determinants by rate pool
- Exhibit 2.2 – 2020 to 2022 Rates Revenue Requirement by rate pool (without Foregone Revenue)
- Exhibit 2.3.1 to 2.3.3 – 2020 Foregone Revenue calculations:
  - Exhibit 2.3.1 2020 UTR for Foregone Revenue calculations
  - Exhibit 2.3.2 2020 Monthly Foregone Revenue calculations
  - Exhibit 2.3.3 Annualized 2020 Foregone Revenue calculations

Tab 3

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Revenue Requirement Summary

($ millions)	Supporting Reference	Hydro One Proposed (Blue Page Update)			Hydro One Proposed [1] (J-8.5)			OEB Decision Impact (Relative to J-8.5)			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022	2020	2021	2022
OM&A [2]	Exhibit 1.1	375.8	381.1	386.4	374.1	380.9	387.7	10.9	9.9	8.9	385.0	390.8	396.7
Depreciation	Exhibit 1.2	474.6	505.2	530.9	474.5	503.4	528.9	(1.0)	(3.2)	(4.4)	473.4	500.2	524.5
Return on Debt	Exhibit 1.4	330.6	349.8	371.8	313.8	332.9	353.7	6.0	1.6	(0.7)	319.8	334.5	353.0
Return on Equity	Exhibit 1.4	444.5	470.3	499.9	421.9	447.5	475.5	(0.7)	(7.0)	(10.7)	421.2	440.6	464.9
Working Capital Reduction	Exhibit 1.9	-	-	-	-	-	-	-	(0.1)	(0.2)	-	(0.1)	(0.2)
Productivity Factor		-	-	-	-	-	-	-	(5.9)	(6.2)	-	(5.9)	(6.2)
Income Tax	Exhibit 1.5	48.3	59.4	64.8	18.1	18.5	31.2	12.1	22.4	8.5	30.1	40.9	39.7
Base Revenue Requirement		**1,673.8**	**1,765.8**	**1,853.8**	**1,602.3**	**1,683.3**	**1,777.1**	**27.3**	**17.7**	**(4.7)**	**1,629.6**	**1,701.0**	**1,772.4**
Deduct: External Revenue	Exhibit 1.6	(31.4)	(32.7)	(32.2)	(31.4)	(32.7)	(32.2)	(5.6)	(5.3)	(5.0)	(37.0)	(38.1)	(37.2)
Subtotal		**1,642.4**	**1,733.0**	**1,821.6**	**1,570.9**	**1,650.5**	**1,744.9**	**21.7**	**12.4**	**(9.7)**	**1,592.6**	**1,662.9**	**1,735.2**
Deduct: Export Tx Service Revenue	Exhibit 1.7	(35.9)	(35.9)	(36.3)	(35.9)	(35.9)	(36.3)	-	-	-	(35.9)	(35.9)	(36.3)
Add: Other Cost Charges (Deferral and Variance Accounts)	Exhibit 1.8	6.8	6.8	6.8	6.8	6.8	6.8	7.8	7.8	7.8	14.7	14.7	14.7
Add: Low Voltage Switch Gear		14.8	15.6	16.3	14.8	15.5	16.3	(0.3)	(0.5)	(0.7)	14.4	15.0	15.6
Deduct: MSP Revenue		(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	(0.1)	-	-	-	(0.1)	(0.1)	(0.1)
Rates Revenue Requirement		**1,628.0**	**1,719.4**	**1,808.4**	**1,556.6**	**1,636.9**	**1,731.6**	**29.2**	**19.7**	**(2.6)**	**1,585.8**	**1,656.6**	**1,729.1**

Note 1: Hydro One Proposed (J-8.5) is referenced in subsequent evidence, the Blue Page update columns are for illustrative purposes only.
Note 2: 2021 and 2022 OM&A is escalated by inflation of 1.8% less productivity factor of 0.3% relative to 2020 OEB approved amount

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

OM&A

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
OM&A	*See supporting details below*	374.1	380.9	387.7	10.9	9.9	8.9	385.0	390.8	396.7

OEB Decision Impact Supporting Details

Adjustments	**OEB Decision Reference**	2020
Compensation related reduction	page 114	(10.1)
OPEB	page 99	21.0
Total Adjustments		10.9

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Rate Base and Depreciation

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Rate Base	*See supporting details below*	12,407.0	13,130.2	13,951.7	(47.4)	(202.9)	(310.8)	12,359.6	12,927.3	13,640.9
Depreciation	*See supporting details below*	474.5	503.4	528.9	(1.0)	(3.2)	(4.4)	473.4	500.2	524.5
OEB Decision Impact Supporting Details	**Reference**	**Detailed Calculation**			**Total Rate Base Impact**					
Working Capital Adjustment										
Rate Base Details										
Utility plant (average)										
Gross plant at cost		19,522.7	20,635.9	21,864.6	(48.5)	(206.8)	(319.4)	19,474.1	20,429.2	21,545.1
Less: Accumulated depreciation		(7,151.0)	(7,543.5)	(7,952.0)	0.5	3.2	8.0	(7,150.5)	(7,540.3)	(7,943.9)
Add: CWIP								-	-	-
Net utility plant		12,371.7	13,092.4	13,912.6	(48.1)	(203.6)	(311.4)	12,323.6	12,888.8	13,601.2
Working capital										
Cash working capital	(a)	23.4	25.6	26.7	0.7	0.7	0.6	24.05	26.24	27.30
Materials & supplies inventory		12.0	12.2	12.4				11.95	12.19	12.43
Total working capital		35.3	37.8	39.1	0.7	0.7	0.6	36.0	38.4	39.7
Removal Acquired LDCs								-	-	-
Total Rate Base		12,407.0	13,130.2	13,951.7	(47.4)	(202.9)	(310.8)	12,359.6	12,927.3	13,640.9
OM&A	(b)	374.1	380.9	387.7						
Cost of Power	(c) Per D1-1-3 Att 1									
Working capital as % of OM&A + COP	(d) = a / (b + c)	6.2%	6.7%	6.9%						
OM&A Reduction per Decision	(e) Exhibit 1.1	10.9	9.9	8.9						
Working capital reduction	(f) = (d) x (e)	0.7	0.7	0.6						
Depreciation		420.9	439.7	461.6						
Depreciation on fixed assets		420.9	439.7	461.6	(1.0)	(3.2)	(4.4)	419.9	436.4	457.2
Capitalized depreciation		(13.3)	(13.5)	(13.6)				(13.3)	(13.5)	(13.6)
Asset removal costs		54.1	59.7	61.5				54.1	59.7	61.5
Other amortization		12.8	17.6	19.4				12.8	17.6	19.4
		474.5	503.4	528.9	(1.0)	(3.2)	(4.4)	473.4	500.2	524.5

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Capital Expenditures

		Hydro One Proposed			OEB Decision Impact			OEB Approved		
($ millions)	**Supporting Reference**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**	**2020**	**2021**	**2022**
Capital expenditures [1]		1,188.0	1,312.5	1,364.2	(86.1)	(143.3)	(237.8)	1,101.9	1,169.2	1,126.4

OEB Decision Impact Supporting Details

Adjustments	**Reference**	2020	2021	2022
Overall capital reduction	page 82	(65.1)	(120.4)	(214.5)
OPEB capital reduction	Page 99	(21.0)	(22.9)	(23.3)
		(86.1)	(143.3)	(237.8)

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Capital Structure and Return on Capital

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Return on Rate Base										
Rate Base		$ 12,407.0	$ 13,130.2	$ 13,951.7	$ (47.4)	$ (202.9)	$ (310.8)	$ 12,359.6	$ 12,927.3	$ 13,640.9
Capital Structure:										
Third-Party long-term debt		0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Deemed long-term debt		56.0%	56.0%	56.0%	0.0%	0.0%	0.0%	56.0%	56.0%	56.0%
Short-term debt		4.0%	4.0%	4.0%	0.0%	0.0%	0.0%	4.0%	4.0%	4.0%
Common equity		40.0%	40.0%	40.0%	0.0%	0.0%	0.0%	40.0%	40.0%	40.0%
Capital Structure:										
Third-Party long-term debt										
Deemed long-term debt		$ 6,947.9	$ 7,352.9	$ 7,813.0	(26.5)	(113.6)	(174.0)	$ 6,921.4	$ 7,239.3	$ 7,638.9
Short-term debt		496.3	525.2	558.1	(1.9)	(8.1)	(12.4)	494.4	517.1	545.6
Common equity		4,962.8	5,252.1	5,580.7	(18.9)	(81.2)	(124.3)	4,943.8	5,170.9	5,456.4
		$ 12,407.0	**$ 13,130.2**	**$ 13,951.7**	**(47.4)**	**(202.9)**	**(310.8)**	**$ 12,359.6**	**$ 12,927.3**	**$ 13,640.9**
Allowed Return:										
Third-Party long-term debt [1]		4.33%	4.33%	4.33%	0.09%	0.09%	0.09%	4.42%	4.42%	4.42%
Deemed long-term debt		4.33%	4.33%	4.33%	0.09%	0.09%	0.09%	4.42%	4.42%	4.42%
Short-term debt		2.75%	2.75%	2.75%	0.00%	0.00%	0.00%	2.75%	2.75%	2.75%
Common equity		8.52%	8.52%	8.52%	0.00%	0.00%	0.00%	8.52%	8.52%	8.52%
Return on Capital:										
Third-Party long-term debt		$ -	$ -	$ -	-	-	-	$ -	$ -	$ -
Deemed long-term debt [2]		$ 300.1	$ 318.5	$ 338.4	6.1	1.8	(0.4)	$ 306.2	$ 320.3	$ 338.0
Short-term debt		$ 13.6	$ 14.4	$ 15.3	(0.1)	(0.2)	(0.3)	$ 13.6	$ 14.2	$ 15.0
Total return on debt		**$ 313.8**	**$ 332.9**	**$ 353.7**	**$ 6.0**	**$ 1.6**	**$ (0.7)**	**$ 319.8**	**$ 334.5**	**$ 353.0**
Common equity [3]		**$ 421.9**	**$ 447.5**	**$ 475.5**	**$ (0.7)**	**$ (7.0)**	**$ (10.7)**	**$ 421.2**	**$ 440.6**	**$ 464.9**

Note 1: Proposed in Argument in Chief November 2019, which reduced the ROE from 8.98% to 8.52% and deemed short term debt rate from 2.82% to 2.75% based on the cost of capital parameters issued by the OEB on October 31, 2019. In addition, the long term debt rate was reduced from 4.57% to 4.33% reflecting both the impact of 2019 actual debt issuances as of April 2019 and the lower forecast interest rates on the remaining 2019 forecast debt issuances and 2020 forecast debt issuances.

Note 2: Hydro One Proposed Long-term debt of $300.1 million for 2020 equals rate base of 12,407 x 56% x 4.33% less $0.4 million reduction to incorporate revenue requirement impact associated with OEB IR -206.

Note 3: Hydro One Proposed Common Equity of $421.9 million for 2020 equals rate base of 12,407 x 40% x 8.52% less $0.7 million reduction to incorporate revenue requirement impact associated with OEB IR -206.

HYDRO ONE NETWORKS INC.
TRANSMISSION
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: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: 1/1/2019 at 12/31/19 ($Millions)	Total Amount Outstanding: 1/1/2020 at 12/31/20 ($Millions)	1/1/2020 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates	
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.400	20.8		
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.272	7.7		
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.000	3.9		
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.000	8.1		
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.000	9.6		
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.000	4.6		
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.000	2.4		
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.000	2.4		
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.900	12.9		
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.500	10.2		
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.000	1.5		
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.000	11.8		
13	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8		
14	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6		
15	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5		
16	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	0.0	83.1	3.7		
17	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5		
18	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1		
19	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8		
20	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0		
21	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1		
22	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8		
23	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0		
24	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4		
25	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1		
26	29-Jan-14	4.310%	29-Jan-64	30.0	0.2	29.8	99.44	4.34%	30.0	30.0	30.0	1.3		
27	3-Jun-14	4.190%	3-Jun-44	198.0	1.2	196.8	99.40	4.23%	198.0	198.0	198.0	8.4		
28	24-Feb-16	3.910%	24-Feb-46	175.0	1.1	173.9	99.36	3.95%	175.0	175.0	175.0	6.9		
29	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.56	2.82%	245.0	245.0	245.0	6.9		
30	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.63	1.92%	250.0	250.0	250.0	4.8		
31	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.50	3.75%	270.0	270.0	270.0	10.1		
32	26-Jun-18	3.630%	25-Jun-49	468.0	2.4	465.6	99.48	3.66%	468.0	468.0	468.0	17.1		
33	26-Jun-18	2.970%	26-Jun-25	218.4	0.9	217.5	99.60	3.03%	218.4	218.4	218.4	6.6		
34	5-Apr-19	3.640%	5-Apr-49	147.5	0.8	146.7	99.43	3.67%	147.5	147.5	147.5	5.4		
35	5-Apr-19	3.020%	5-Apr-29	324.5	1.4	323.1	99.57	3.07%	324.5	324.5	324.5	10.0		
36	5-Apr-19	2.540%	5-Apr-24	413.0	1.6	411.4	99.62	2.62%	413.0	413.0	413.0	10.8		
37	15-Nov-19	3.205%	15-Nov-49	0.0	0.0	0.0	100.00	3.21%	0.0	0.0	0.0	0.0		Note 1
38	15-Nov-19	2.555%	15-Nov-29	0.0	0.0	0.0	100.00	2.56%	0.0	0.0	0.0	0.0		Note 1
39	15-Nov-19	2.226%	15-Nov-24	0.0	0.0	0.0	100.00	2.23%	0.0	0.0	0.0	0.0		Note 1
40	15-Mar-20	3.305%	15-Mar-50	163.0	0.8	162.2	99.50	3.33%	0.0	163.0	125.4	4.2		
41	15-Jun-20	2.655%	15-Jun-30	163.0	0.8	162.2	99.50	2.71%	0.0	163.0	87.8	2.4		
42	15-Sep-20	2.326%	15-Sep-25	163.0	0.8	162.2	99.50	2.43%	0.0	163.0	50.2	1.2		
43		**Subtotal**							6243.0	6552.0	6409.4	276.4		
45		Treasury OM&A costs										1.9		
46		Other financing-related fees										5.3		
47		**Total**							6243.0	6552.0	6409.4	283.6	4.42%	

Note 1: Updated 2020 ECD – AIC debt schedule prepared in November 2019, to reflect actual debt issuance in 2019 which only occurred in April 2019, and the removal of forecasted November 2019 issuances which did not occur, as stated in Reply Argument, page 213, lines 16 to 17, " As stated in Exhibit G, Tab 1, Schedule 1 and consistent with prior practice, Hydro One intends to update the rate at the Draft Rate Order stage to reflect actual debt issuances for 2019."

TRANSMISSION
Cost of Long-Term Debt Capital
For informational purposes only. Superseded by calculation in Exhibit 1.4.1 for purposes of revenue requirement calculation.
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: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	1/1/2019 Total Amount Outstanding at 12/31/2019 ($Millions)	1/1/2020 Total Amount Outstanding at 12/31/2020 ($Millions)	1/1/2020 Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates	
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)	
1	3-Jun-00	7.350%	3-Jun-30	278.4	4.5	273.9	98.37	7.49%	278.4	278.4	278.4	20.8		
2	22-Jun-01	6.930%	1-Jun-32	109.3	1.3	107.9	98.78	7.03%	109.3	109.3	109.3	7.7		
3	17-Sep-02	6.930%	1-Jun-32	58.0	(2.1)	60.1	103.57	6.65%	58.0	58.0	58.0	3.9		
4	31-Jan-03	6.350%	31-Jan-34	126.0	1.0	125.0	99.21	6.41%	126.0	126.0	126.0	8.1		
5	22-Apr-03	6.590%	22-Apr-43	145.0	1.1	143.9	99.26	6.64%	145.0	145.0	145.0	9.6		
6	25-Jun-04	6.350%	31-Jan-34	72.0	(0.2)	72.2	100.22	6.33%	72.0	72.0	72.0	4.6		
7	20-Aug-04	6.590%	22-Apr-43	39.0	(3.1)	42.1	107.89	6.06%	39.0	39.0	39.0	2.4		
8	24-Aug-04	6.350%	31-Jan-34	39.0	(1.4)	40.4	103.48	6.09%	39.0	39.0	39.0	2.4		
9	19-May-05	5.360%	20-May-36	228.9	8.7	220.2	96.19	5.62%	228.9	228.9	228.9	12.9		
10	24-Apr-06	5.360%	20-May-36	187.5	2.5	185.0	98.68	5.45%	187.5	187.5	187.5	10.2		
11	19-Oct-06	5.000%	19-Oct-46	30.0	0.2	29.8	99.29	5.04%	30.0	30.0	30.0	1.5		
12	13-Mar-07	4.890%	13-Mar-37	240.0	1.3	238.7	99.45	4.93%	240.0	240.0	240.0	11.8		
13	3-Mar-09	6.030%	3-Mar-39	195.0	1.2	193.8	99.41	6.07%	195.0	195.0	195.0	11.8		
14	16-Jul-09	5.490%	16-Jul-40	210.0	1.4	208.6	99.36	5.53%	210.0	210.0	210.0	11.6		
15	15-Mar-10	5.490%	24-Jul-40	120.0	(0.7)	120.7	100.58	5.45%	120.0	120.0	120.0	6.5		
16	15-Mar-10	4.400%	4-Jun-20	180.0	0.8	179.2	99.55	4.46%	180.0	0.0	83.1	3.7		
17	13-Sep-10	5.000%	19-Oct-46	150.0	(0.4)	150.4	100.25	4.98%	150.0	150.0	150.0	7.5		
18	26-Sep-11	4.390%	26-Sep-41	205.0	1.3	203.7	99.35	4.43%	205.0	205.0	205.0	9.1		
19	22-Dec-11	4.000%	22-Dec-51	70.0	0.4	69.6	99.47	4.03%	70.0	70.0	70.0	2.8		
20	13-Jan-12	3.200%	13-Jan-22	154.0	0.8	153.2	99.47	3.26%	154.0	154.0	154.0	5.0		
21	22-May-12	3.200%	13-Jan-22	165.0	(1.6)	166.6	100.97	3.08%	165.0	165.0	165.0	5.1		
22	22-May-12	4.000%	22-Dec-51	68.8	0.3	68.4	99.51	4.02%	68.8	68.8	68.8	2.8		
23	31-Jul-12	3.790%	31-Jul-62	52.5	0.3	52.2	99.47	3.81%	52.5	52.5	52.5	2.0		
24	16-Aug-12	3.790%	31-Jul-62	141.0	1.1	139.9	99.20	3.83%	141.0	141.0	141.0	5.4		
25	9-Oct-13	4.590%	9-Oct-43	239.3	1.4	237.9	99.42	4.63%	239.3	239.3	239.3	11.1		
26	29-Jan-14	4.310%	29-Jan-64	30.0	0.2	29.8	99.44	4.34%	30.0	30.0	30.0	1.3		
27	3-Jun-14	4.190%	3-Jun-44	198.0	1.2	196.8	99.40	4.23%	198.0	198.0	198.0	8.4		
28	24-Feb-16	3.910%	24-Feb-46	175.0	1.1	173.9	99.36	3.95%	175.0	175.0	175.0	6.9		
29	24-Feb-16	2.770%	24-Feb-26	245.0	1.1	243.9	99.56	2.82%	245.0	245.0	245.0	6.9		
30	24-Feb-16	1.840%	24-Feb-21	250.0	0.9	249.1	99.63	1.92%	250.0	250.0	250.0	4.8		
31	18-Nov-16	3.720%	18-Nov-47	270.0	1.4	268.7	99.50	3.75%	270.0	270.0	270.0	10.1		
32	26-Jun-18	3.630%	25-Jun-49	468.0	2.4	465.6	99.48	3.66%	468.0	468.0	468.0	17.1		
33	26-Jun-18	2.970%	26-Jun-25	218.4	0.9	217.5	99.60	3.03%	218.4	218.4	218.4	6.6		
34	5-Apr-19	3.640%	5-Apr-49	147.5	0.8	146.7	99.43	3.67%	147.5	147.5	147.5	5.4		Note 1
35	5-Apr-19	3.020%	5-Apr-29	324.5	1.4	323.1	99.57	3.07%	324.5	324.5	324.5	10.0		Note 1
36	5-Apr-19	2.540%	5-Apr-24	413.0	1.6	411.4	99.62	2.62%	413.0	413.0	413.0	10.8		Note 1
37	15-Nov-19	3.205%	15-Nov-49	125.2	0.6	124.6	99.50	3.23%	125.2	125.2	125.2	4.0		Note 1
38	15-Nov-19	2.555%	15-Nov-29	125.2	0.6	124.6	99.50	2.61%	125.2	125.2	125.2	3.3		Note 1
39	15-Nov-19	2.226%	15-Nov-24	125.2	0.6	124.6	99.50	2.33%	125.2	125.2	125.2	2.9		Note 1
40	15-Mar-20	3.305%	15-Mar-50	163.0	0.8	162.2	99.50	3.33%	0.0	163.0	125.4	4.2		Note 2
41	15-Jun-20	2.655%	15-Jun-30	163.0	0.8	162.2	99.50	2.71%	0.0	163.0	87.8	2.4		Note 2
42	15-Sep-20	2.326%	15-Sep-25	163.0	0.8	162.2	99.50	2.43%	0.0	163.0	50.2	1.2		Note 2
43		**Subtotal**							6618.7	6927.7	6785.1	286.6		
44		Treasury OM&A costs										1.9		
45		Other financing-related fees										5.3		
46		**Total**							6618.7	6927.7	6785.1	293.8	4.33%	Note 3

Note 1: Updated to reflect actual debt issuance and planned debt in 2019
Note 2: Updated to reflect the forecast coupon rates for 2020 as per the September 2019 Consensus Forecast
Note 3: As stated in the Reply Argument, page 213, lines 12 to 17, "4.33% reflects actual debt issuances as of April 2019 and forecasted debt issuances for the balance of 2019 as presented in response to LPMA IR 19 and further updated to reflect Hydro One's long term interest rates for 2019 and 2020 consistent with the update of the other cost of capital parameters using September 2019 Consensus Forecast data. As stated in Exhibit G, Tab 1, Schedule 1 and consistent with prior practice, Hydro One intends to update the rate at the Draft Rate Order stage to reflect actual debt issuances for 2019."

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Income Tax

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Income Taxes	*See supporting details below*	18.1	18.5	31.2	12.1	22.4	8.5	30.1	40.9	39.7

Income Tax Supporting Details

			Hydro One Proposed 2020	Hydro One Proposed 2021	Hydro One Proposed 2022	OEB Decision Impact 2020	OEB Decision Impact 2021	OEB Decision Impact 2022	OEB Approved 2020	OEB Approved 2021	OEB Approved 2022
Rate Base	Exhibit 1.2	(a)	$ 12,407.0	$ 13,130.2	$ 13,951.7	$ (47.4)	$ (202.9)	$ (310.8)	$ 12,359.6	$ 12,927.3	$ 13,640.9
Common Equity Capital Structure		(b)	40.0%	40.0%	40.0%				40.0%	40.0%	40.0%
Return on Equity	Exhibit 1.4	(c)	8.52%	8.52%	8.52%				8.52%	8.52%	8.52%
Return on Equity		(d) = a x b x c	421.9	447.5	475.5	(0.7)	(6.9)	(10.6)	421.2	440.6	464.9
Regulatory Income Tax		(e) = l	50.8	49.0	59.6	12.1	22.4	8.5	62.9	71.4	68.1
Regulatory Net Income (before tax)		(f) = d + e	472.7	496.5	535.0	11.4	15.5	(2.1)	484.1	512.0	533.0
Timing Differences *(Note 1)*		(g)	(279.6)	(310.2)	(308.9)	34.1	69.0	34.2	(245.4)	(241.2)	(274.7)
Taxable Income		(h) = f + g	193.1	186.3	226.1	45.5	84.5	32.1	238.7	270.8	258.2
Tax Rate		(i)	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%	26.5%
Income Tax		(j) = h x i	51.2	49.4	59.9	12.1	22.4	8.5	63.2	71.8	68.4
less: Income Tax Credits		(k)	(0.3)	(0.4)	(0.3)				(0.3)	(0.4)	(0.3)
Regulatory Income Tax		(l) = j + k	50.8	49.0	59.6	12.1	22.4	8.5	62.9	71.4	68.1
Max CCA			(251.2)	(233.7)	(217.3)				(251.2)	(233.7)	(217.3)
Tax Effected (26.5%)			(66.6)	(61.9)	(57.6)	-	-	-	(66.6)	(61.9)	(57.6)
Less: DTA Sharing (36.2%)			(24.1)	(22.4)	(20.8)	-	-	-	(24.1)	(22.4)	(20.8)
Less: DTA Sharing - G/up			(8.7)	(8.1)	(7.5)	-	-	-	(8.7)	(8.1)	(7.5)
Total Deferred Tax Asset Sharing			(32.8)	(30.5)	(28.4)	-	-	-	(32.8)	(30.5)	(28.4)
			(32.8)	(30.5)	(28.4)						
Income Taxes			18.1	18.5	31.2	12.1	22.4	8.5	30.1	40.9	39.7
Note 1. Book to Tax Timing Differences											
Depreciation			474.5	503.4	528.9	(1.0)	(3.2)	(4.4)	473.4	500.2	524.5
CCA			(681.4)	(732.6)	(752.8)	5.7	42.1	7.6	(675.7)	(690.5)	(745.2)
Other Timing Differences			(72.7)	(81.1)	(85.0)	29.5	30.2	31.0	(43.1)	(50.9)	(54.0)
Total Timing Differences			(279.6)	(310.2)	(308.9)	34.1	69.0	34.2	(245.4)	(241.2)	(274.7)

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Utility Income Taxes
Test Years (2020 to 2022)
Year Ending December 31
($ Millions)

Line No.	Particulars		2020		2021		2022	
	Determination of Taxable Income							
1	Regulatory Net Income (before tax)	$	484.1	$	512.0	$	533.0	
2	Book to Tax Adjustments:							
3	Other Post Employment Benefits expense		49.6		50.3		50.2	
4	Other Post Employment Benefits payments		(28.7)		(30.7)		(31.3)	
5	Depreciation and amortization		473.4		500.2		524.5	
6	Capital Cost Allowance		(675.7)		(690.5)		(745.2)	
7	Removal costs		(3.3)		(3.3)		(3.3)	
8	Environmental costs		(12.6)		(17.4)		(19.3)	
9	Hedge loss - amortization		0.0		0.0		0.0	
10	Non-deductible meals & entertainment		3.4		3.4		3.4	
11	Capital amounts expensed under $2K		4.3		4.3		4.3	
12	Research & Development ITC		0.0		0.0		0.0	
13	Federal apprenticeship & education credits		0.3		0.4		0.3	
14	Capitalized overhead costs		(34.7)		(35.7)		(36.0)	
15	Capitalized pension costs		(23.8)		(25.1)		(24.9)	
16	Debt Issuance costs - amortization		2.2		2.2		2.2	
17	Debt Issuance costs - 21e deduction		(3.5)		(2.8)		(3.4)	
18	Premium/Discount - amortization		(0.3)		(0.4)		(0.1)	
19	Bond discount deduction		(0.0)		(0.1)		0.0	
20	Non-deductible LTIP		2.7		2.8		2.8	
21	Capital Contribution True-Up Adjustment		0.0		0.0		0.0	
22	Other		1.4		1.3		1.2	
		$	(245.4)	$	(241.2)	$	(274.7)	
23	Regulatory Taxable Income	$	238.7	$	270.8	$	258.2	
24	Corporate Income Tax Rate		26.50	%	26.50	%	26.50	%
25	Subtotal	$	63.2	$	71.8	$	68.4	
26	Less: R&D ITC / Ontario education credits		(0.3)		(0.4)		(0.3)	
27	Regulatory Income Tax	$	62.9	$	71.4	$	68.1	
28	Less: Deferred Tax Asset Sharing		(32.8)		(30.5)		(28.4)	
29	Revenue Requirment Income Tax	$	30.1	$	40.9	$	39.7	
	Tax Rates							
30	Federal Tax		15.00	%	15.00	%	15.00	%
31	Provincial Tax		11.50	%	11.50	%	11.50	%
32	Total Tax Rate		26.50	%	26.50	%	26.50	%

HYDRO ONE NETWORKS INC.
TRANSMISSION
Calculation of Capital Cost Allowance (CCA)
2020 to 2022 Networks Allocation to Tx
Year Ending December 31
($ Millions)

2020

CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	Adjusted Additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,850.0	21.8	1,871.8	30.1	1,880.1	4%	75.2	1,796.6
2	418.2	0.0	418.2	-	418.2	6%	25.1	393.1
3	206.1	0.0	206.1	-	206.1	5%	10.3	195.8
6	55.0	0.0	55.0	-	55.0	10%	5.5	49.5
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	154.7	41.1	195.7	56.7	211.3	20%	42.3	153.5
9	0.3	0.0	0.3	-	0.3	25%	0.1	0.2
10	31.9	7.8	39.7	10.7	42.6	30%	12.8	26.9
12	12.6	26.4	39.0	24.8	37.4	100%	37.4	1.6
13	7.2	(1.0)	6.3	-	7.2	0%	0.9	5.4
14.1	14.7	5.0	19.7	6.9	21.7	5%	1.1	18.7
17	104.5	1.1	105.6	1.5	106.0	8%	8.5	97.1
35	0.1	0.0	0.1	-	0.1	7%	0.0	0.1
42	57.1	0.0	57.1	-	57.1	12%	6.9	50.3
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	7.0	0.0	7.0	-	7.0	30%	2.1	4.9
47	4,250.5	742.7	4,993.2	1,025.0	5,275.5	8%	422.0	4,571.2
50	51.4	3.5	54.9	4.9	56.2	55%	30.9	24.0
52	-	0.0	-	-	-	100%	-	-
	7,221.3	848.4	8,069.7	1,160.5	8,381.8		681.0	7,388.7
Tx CEC Continuity	36.3	0.0	36.3	0.0	36.3	0.1	2.5	33.7
			Non-Regulatory				(7.8)	
			Plus: Adjustment to CCA re goodwill					
			Total CCA for RR				675.7	

2021 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	Adjusted Additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,796.6	27.4	1,824.0	38.8	1,835.4	4%	73.4	1,750.5
2	393.1	0.0	393.1	-	393.1	6%	23.6	369.5
3	195.8	0.0	195.8	-	195.8	5%	9.8	186.0
6	49.5	0.0	49.5	-	49.5	10%	4.9	44.5
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	153.5	94.1	247.5	133.6	287.0	20%	57.4	190.1
9	0.2	0.0	0.2	-	0.2	25%	0.1	0.2
10	26.9	8.5	35.4	12.0	38.9	30%	11.7	23.7
12	1.6	19.8	21.4	19.0	20.6	100%	20.6	0.8
13	5.4	(0.4)	5.0	-	5.4	0%	0.5	4.5
14.1	18.7	11.0	29.6	15.6	34.2	5%	1.7	27.9
17	97.1	2.4	99.5	3.4	100.5	8%	8.0	91.5
35	0.1	0.0	0.1	-	0.1	7%	0.0	0.1
42	50.3	0.0	50.3	-	50.3	12%	6.0	44.3
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	4.9	0.0	4.9	-	4.9	30%	1.5	3.4
47	4,571.2	794.9	5,366.1	1,128.8	5,699.9	8%	456.0	4,910.1
50	24.0	8.8	32.7	12.4	36.4	55%	20.0	12.7
52	-	0.0	-	-	-	100%	-	-
	7,388.7	966.3	8,355.0	1,363.7	8,752.3		695.2	7,659.8
Tx CEC Continuity	33.7	0.0	33.7	0.0	33.7	0.1	2.4	31.4
			Non-Regulatory				(7.1)	
			Plus: Adjustment to CCA re goodwill					
			Total CCA for RR				690.5	

2022 CCA Class	Opening UCC	Net Additions	UCC pre-1/2 yr	Adjusted Additions	UCC for CCA	CCA Rate	CCA	Closing UCC
1	1,750.5	30.1	1,780.6	45.1	1,795.6	4%	71.8	1,708.8
2	369.5	0.0	369.5	-	369.5	6%	22.2	347.4
3	186.0	0.0	186.0	-	186.0	5%	9.3	176.7
6	44.5	0.0	44.5	-	44.5	10%	4.5	40.1
7	0.0	0.0	0.0	-	0.0	15%	0.0	0.0
8	190.1	65.0	255.1	97.5	287.6	20%	57.5	197.6
9	0.2	0.0	0.2	-	0.2	25%	0.0	0.1
10	23.7	8.6	32.3	12.9	36.6	30%	11.0	21.3
12	0.8	29.2	30.0	29.2	30.0	100%	30.0	-
13	4.5	(0.9)	3.6	-	4.5	0%	(0.2)	3.9
14.1	27.9	10.3	38.2	15.4	43.3	5%	2.2	36.0
17	91.5	2.8	94.3	4.3	95.7	8%	7.7	86.7
35	0.1	0.0	0.1	-	0.1	7%	0.0	0.1
42	44.3	0.0	44.3	-	44.3	12%	5.3	38.9
45	0.0	0.0	0.0	-	0.0	45%	0.0	0.0
46	3.4	0.0	3.4	-	3.4	30%	1.0	2.4
47	4,910.1	1019.8	5,929.8	1,529.6	6,439.7	8%	515.2	5,414.7
50	12.7	6.3	19.0	9.4	22.1	55%	12.2	6.8
52	-	0.0	-	-	-	100%	-	-
	7,659.8	1,171.1	8,830.9	1,743.4	9,403.2		749.5	8,081.4
Tx CEC Continuity	31.4	0.0	31.4	0.0	31.4	0.1	2.2	29.2
			Non-Regulatory				(6.5)	
			Plus: Adjustment to CCA re goodwill					
			Total CCA for RR				745.2	

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

External Revenue

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
External Revenue	*See supporting details below*	31.4	32.7	32.2	5.6	5.3	5.0	37.0	38.1	37.2

External Revenue and Other – Hydro One's Reply Argument p 221									
Secondary Land Use	17.9	18.2	18.5	5.6	5.3	5.0	23.5	23.5	23.5
Station Maintenance	4.0	4.0	4.0				4.0	4.0	4.0
Engineering & Construction	0.3	0.3	0.3				0.3	0.3	0.3
Other External Revenues	9.2	10.3	9.4				9.2	10.3	9.4
External Revenue	31.4	32.7	32.2	5.6	5.3	5.0	37.0	38.1	37.2

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Export Transmission Service Revenue

($ millions)	Supporting Reference	Hydro One Proposed			OEB Decision Impact			OEB Approved		
		2020	2021	2022	2020	2021	2022	2020	2021	2022
Export Tx Service Revenue		35.9	35.9	36.3	-	-	-	35.9	35.9	36.3

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Deferral and Variance Accounts

($ millions)	Supporting Reference	Hydro One Proposed Total	Hydro One Proposed 2020	Hydro One Proposed 2021	Hydro One Proposed 2022	OEB Decision Impact Total	OEB Decision Impact 2020	OEB Decision Impact 2021	OEB Decision Impact 2022	OEB Approved Total	OEB Approved 2020	OEB Approved 2021	OEB Approved 2022
Deferral and Variance Accounts Disposition	*See supporting details below*	*20.5*	6.8	6.8	6.8	*23.5*	7.8	7.8	7.8	*44.0*	14.7	14.7	14.7

Transmission Regulatory Account Balances for Disposition

	Hydro One Proposed	OEB Decision Impact	OEB Approved
Excess Export Service Revenue	4.8	-	4.8
External Secondary Land Use Revenue	(10.4)	(0.1)	(10.5)
External Stations Maintenance, E&CS & Other External Revenue	4.5	0.1	4.6
Tax Rate Changes	-	-	-
Rights Payments	2.4	-	2.4
Pension Costs Differential	(4.5)	-	(4.5)
Long-Term Transmission Future Corridor Acquisition and Development	-	-	-
LDC CDM and Demand Response Variance Account	23.6	0.3	23.9
External Revenue - Partnership Transmission Projects Account	(0.0)	-	(0.0)
OEB Cost Differential Account	(0.1)	-	(0.1)
Waasigan Transmission Line Deferral (Formaerly NWBTL)	0.9	-	0.9
OPEB Cost Deferral Account		23.2	23.2
In-Service Capital Additions Variance	(0.6)	(0.1)	(0.7)
Total	**20.5**	**23.5**	**44.0**

Hydro One Networks Inc.
Implementation of Decision with Reasons on EB-2019-0082

Working Capital Adjustment

	2020	2021	2022
Total Working Capital Proposed in Rate Base	35.3	37.8	39.1
Adjustment to Working Capital as a result of OM&A change	0.7	0.7	0.6
Adjusted Working Capital in Rate Base	**36.0**	**38.4**	**39.7**
Long-term debt	4.4%	4.4%	4.4%
Short-term debt	2.8%	2.8%	2.8%
Common equity	8.5%	8.5%	8.5%
Return on Long-term debt	0.9	1.0	1.0
Return on Short-term debt	0.0	0.0	0.0
Return on Common equity	1.2	1.3	1.4
Total Return on Capital	2.2	2.3	2.4
Income tax	0.4	0.5	0.5
Total Revenue Requirement Associated with Working Capital in Rate Base	**2.6**	**2.8**	**2.9**
Revenue Requirement Associated with Working Capital in rate base	2.6	2.8	2.9
Less Productivity Factor applied to Working Capital	-	(0.0)	(0.0)
Revenue Requirement calculation (prior methodology)	**2.6**	**2.8**	**2.9**
Revenue Requirement calculation (OEB Decision) [1]	**2.6**	**2.6**	**2.7**
Difference between the two methodologies	-	(0.1)	(0.2)

Note 1: The calculation for revenue requirement associated with working capital based on the OEB decision to exclude recovering incremental revenue associated with working capital as part of the capital factor

HYDRO ONE NETWORKS INC. IMPLEMENTATION OF DECISION WITH REASONS ON EB-2019-0082

Updated Exhibit E-03-01, Table 3: Load Forecast Before and After Embedded Generation and CDM
(12-Month Average Peak in MW)

		Charge Determinant		
Year	Ontario Demand	Network Connection	Line Connection	Transformation Connection
Load Forecast before Deducting Impacts of Embedded Generation and CDM				
2017	21,902	21,912	21,202	18,100
2018	22,159	22,183	21,535	18,375
2019	22,450	22,470	21,807	18,584
2020	22,842	22,863	22,188	18,909
2021	22,812	22,833	22,159	18,884
2022	22,799	22,820	22,147	18,873
Load Impact of Embedded Generation				
2017	568	568	513	438
2018	578	579	525	448
2019	602	603	543	463
2020	703	704	639	545
2021	703	704	639	545
2022	703	704	639	545
Load Impact of CDM				
2017	1,638	1,639	1,589	1,356
2018	1,924	1,926	1,873	1,598
2019	2,252	2,254	2,186	1,863
2020	2,552	2,555	2,478	2,112
2021	2,552	2,555	2,478	2,112
2022	2,552	2,555	2,478	2,112
Load Forecast after Deducting Embedded Generation and CDM				
2017	19,696	19,705	19,100	16,306
2018	19,657	19,678	19,137	16,329
2019	19,595	19,614	19,078	16,258
2020	19,586	19,604	19,071	16,252
2021	19,556	19,574	19,041	16,227
2022	19,543	19,561	19,029	16,217

Note: All figures are weather-normal.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Charge Determinants for 2020-2022

Rate Pool	Total MW (Note 1)		
	2020	2021	2022
Network	235,253	234,887	234,736
Line Connection	228,853	228,497	228,350
Transformation Connection	195,027	194,724	194,599

Note 1: Sum of 12 monthly charge determinant.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Table 1: 2020 Revenue Requirement by Rate Pool

	Supporting Exhibit	2020 Rate Pool Revenue Requirement ($ Million)			
		Network	Line Connection	Transformation Connection	Uniform Transmission Rates Revenue Requirement
OM&A	*1.1 (Note1)*	$187.1	$38.9	$90.9	$316.9
Other Taxes (Grants-in-Lieu)	*1.1 (Note1)*	$42.7	$7.9	$17.6	$68.1
Depreciation of Fixed Assets	*1.2 (Note2)*	$253.8	$42.0	$124.0	$419.9
Capitalized Depreciation	*1.2 (Note2)*	($8.3)	($1.5)	($3.5)	($13.3)
Asset Removal Costs	*1.2 (Note2)*	$33.8	$6.2	$14.2	$54.1
Other Amortization	*1.2 (Note2)*	$8.0	$1.5	$3.3	$12.8
Return on Debt	*1.4*	$200.3	$37.0	$82.5	$319.8
Return on Equity	*1.4*	$263.8	$48.8	$108.7	$421.2
Income Tax	*1.5*	$18.9	$3.5	$7.8	$30.1
Base Revenue Requirement		**$1,000.0**	**$184.3**	**$445.4**	**$1,629.6**
External Revenue	*1.6*	($22.7)	($4.2)	($10.1)	($37.0)
Total Revenue Requirement		**$977.3**	**$180.1**	**$435.2**	**$1,592.6**
WMS Revenue	*Note 3*			($0.1)	($0.1)
Export Revenue	*1.7*	($35.9)			($35.9)
Deferral & Variance Account Disposition	*1.8*	$9.6	$1.5	$3.6	$14.7
LVSG Credit	*2.7*			$14.4	$14.4
Total Rates Revenue Requirement		**$951.0**	**$181.6**	**$453.2**	**$1,585.8**

Note 1: Included in OEB Approved 2020 OMA total in Exhibit 1.1.
Note 2: Included in OEB Approved 2020 Depreciation total in Exhibit 1.2.
Note 3: OEB Approved WMS revenue per Decision and Order in EB-2019-0082, pg. 158.

Table 2: Percentage Split of Base Revenue Requirement by Transmission Rate Pool

	Network	Line Connection	Transformation Connection	Total
2020 Base Revenue Requirement	**$1,000.0**	**$184.3**	**$445.4**	**$1,629.6**
Percentage Split by Rate Pool	61%	11%	27%	100%

Table 3: 2021 Revenue Requirement by Rate Pool ($ Million)

	Network	Line Connection	Transformation Connection	Total
Percentage Split by Rate pool	61%	11%	27%	100%
Base Revenue Requirement	**$1,043.8**	**$192.3**	**$464.9**	**$1,701.0**
External Revenue	($23.4)	($4.3)	($10.4)	($38.1)
WMS Revenue			($0.1)	($0.1)
Export Revenue	($35.9)			($35.9)
Deferral & Variance Account Disposition	$9.6	$1.5	$3.6	$14.7
LVSG Credit			$15.0	$15.0
Total Rates Revenue Requirement	**$994.1**	**$189.5**	**$473.0**	**$1,656.6**

Table 4: 2022 Revenue Requirement by Rate Pool ($ Million)

	Network	Line Connection	Transformation Connection	Total
Percentage Split by Rate pool	61%	11%	27%	100%
Base Revenue Requirement	**$1,087.6**	**$200.4**	**$484.4**	**$1,772.4**
External Revenue	($22.8)	($4.2)	($10.2)	($37.2)
WMS Revenue			($0.1)	($0.1)
Export Revenue	($36.3)			($36.3)
Deferral & Variance Account Disposition	$9.6	$1.5	$3.6	$14.7
LVSG Credit			$15.6	$15.6
Total Rates Revenue Requirement	**$1,038.1**	**$197.7**	**$493.3**	**$1,729.1**

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020 Interim Uniform Transmission Rates and Revenue Disbursement Allocators (Updated for H1N's 2020 Charge Determinants and Revenue Requirement, excluding 2020 Foregone Revenue)

Effective January 1, 2020 to December 31, 2020

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,790,719	$914,623	$2,282,750	$7,988,092
CNPI	$2,787,078	$532,096	$1,328,027	$4,647,201
H1N SSM	$24,480,432	$4,673,695	$11,664,787	$40,818,914
H1N	$951,027,050	$181,565,841	$453,159,011	$1,585,751,902
B2MLP	$32,464,151	$0	$0	$32,464,151
NRLP	$9,389,914	$0	$0	$9,389,914
All Transmitters	$1,024,939,344	$187,686,255	$468,434,575	$1,681,060,174

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	235,252.608	228,852.936	195,027.487	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,504.148	232,385.678	196,285.037	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**4.28**	**0.81**	**2.39**	
FNEI Allocation Factor	**0.00467**	**0.00487**	**0.00487**	
CNPI Allocation Factor	**0.00272**	**0.00284**	**0.00284**	
H1N SSM Allocation Factor	**0.02388**	**0.02490**	**0.02490**	
H1N Allocation Factor	**0.92790**	**0.96739**	**0.96739**	
B2MLP Allocation Factor	**0.03167**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.00916**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-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: H1N SSM 2020 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0266 dated December 17, 2019.

Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0082, issued April 23, 2020, as per Exhibit 2.2, Table 1.

Note 5: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.

Note 6: NRLP 2020 Interim Revenue Requirement per OEB Decision and Order EB-2018-0275 December 19, 2019.

Note 7: Calculated data in shaded cells.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020 Foregone Revenue Calculation

Table 1 - HONI Transmission Charge Determinant Forecast for the Year 2020 (MW)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	19,819	19,585	18,899	17,431	18,573	20,969	21,952	21,462	19,838	17,848	18,963	19,916	235,253
Line Connection	19,027	18,888	18,096	16,875	18,261	20,052	21,443	20,836	19,425	17,750	18,431	19,770	228,853
Transformation Connection	16,265	16,204	15,558	14,317	15,623	17,203	18,432	17,785	16,900	14,558	15,443	16,739	195,027

Table 2 - Monthly Charge Determinant Share of Annual Total

% Share	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	8.42%	8.32%	8.03%	7.41%	7.89%	8.91%	9.33%	9.12%	8.43%	7.59%	8.06%	8.47%	100.00%
Line Connection	8.31%	8.25%	7.91%	7.37%	7.98%	8.76%	9.37%	9.10%	8.49%	7.76%	8.05%	8.64%	100.00%
Transformation Connection	8.34%	8.31%	7.98%	7.34%	8.01%	8.82%	9.45%	9.12%	8.67%	7.46%	7.92%	8.58%	100.00%

Table 3 - 2020 UTR Charge Determinant (including all Transmitters)

Charge Determinant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	20,177	19,938	19,241	17,746	18,908	21,348	22,348	21,850	20,196	18,170	19,305	20,276	239,504
Line Connection	19,321	19,179	18,376	17,135	18,543	20,362	21,774	21,157	19,725	18,024	18,715	20,075	232,386
Transformation Connection	16,370	16,309	15,658	14,410	15,724	17,314	18,551	17,899	17,009	14,652	15,543	16,847	196,285

Table 4 - 2020 Interim UTR*

	$/kw-month	Hydro One Revenue Allocators
Network	3.92	0.92606
Line Connection	0.97	0.96747
Transformation Connection	2.33	0.96747

* As per Exhibit 2.5.1

Table 5 - 2020 Revenue at 2020 Interim UTR and 2020 Load Forecast (Table 3 x Table 4)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	73.2	72.4	69.8	64.4	68.6	77.5	81.1	79.3	73.3	66.0	70.1	73.6	869.4
Line Connection	18.1	18.0	17.2	16.1	17.4	19.1	20.4	19.9	18.5	16.9	17.6	18.8	218.1
Transformation Connection	36.9	36.8	35.3	32.5	35.4	39.0	41.8	40.3	38.3	33.0	35.0	38.0	442.5
Total	**128.3**	**127.1**	**122.4**	**113.0**	**121.5**	**135.6**	**143.4**	**139.5**	**130.2**	**115.9**	**122.7**	**130.4**	**1,530.0**

Table 6 - Proposed 2020 UTR**

	$/kw-month	Hydro One Revenue Allocators
Network	4.28	0.92790
Line Connection	0.81	0.96739
Transformation Connection	2.39	0.96739

** As per Exhibit 2.3.1

Table 7 - 2020 Revenue at Proposed 2020 UTR and 2020 Load Forecast (Table 3 x Table 6)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	80.1	79.2	76.4	70.5	75.1	84.8	88.8	86.8	80.2	72.2	76.7	80.5	951.2
Line Connection	15.1	15.0	14.4	13.4	14.5	16.0	17.1	16.6	15.5	14.1	14.7	15.7	182.1
Transformation Connection	37.8	37.7	36.2	33.3	36.4	40.0	42.9	41.4	39.3	33.9	35.9	39.0	453.8
Total	**133.1**	**131.9**	**127.0**	**117.2**	**126.0**	**140.8**	**148.7**	**144.7**	**135.0**	**120.2**	**127.3**	**135.2**	**1,587.1**

Table 8 - 2020 Forgone Revenue (Table 7 Revenue at Proposed Rates - Table 5 Revenue at Current Rates)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual Total
Network	6.9	6.8	6.6	6.1	6.5	7.3	7.6	7.5	6.9	6.2	6.6	6.9	81.7
Line Connection	-3.0	-3.0	-2.8	-2.7	-2.9	-3.2	-3.4	-3.3	-3.1	-2.8	-2.9	-3.1	-36.0
Transformation Connection	0.9	0.9	0.9	0.8	0.9	1.0	1.1	1.0	1.0	0.8	0.9	1.0	11.4
Total	**4.8**	**4.8**	**4.6**	**4.2**	**4.5**	**5.1**	**5.3**	**5.2**	**4.8**	**4.3**	**4.6**	**4.8**	**57.1**

Foregone Revenue for January 1, 2020 to June 30, 2020: **$28,104,803**

Foregone Revenue for January 1, 2020 to December 31, 2020: **$57,101,636**

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Derivation of Annualized 2020 Foregone Revenue

Rate Pool	Sum of 12 Monthly Charge Determinants (A)	Sum of Monthly Charge Determinants for Jul-Dec (B)	Foregone Revenue for January to June 2020* (C)	Annualized Foregone Revenue (D=A/B*C)
Network	239,504	122,146	$40,049,135	$78,528,185
Line Connection	232,386	119,470	($17,486,131)	($34,012,961)
Transformation Connection	196,285	100,501	$5,541,799	$10,823,537
			$28,104,803	**$55,338,761**

* As per Exhibit 2.3.2

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020 Rates Revenue Requirement for Uniform Transmission Rates To Be Implemented on July 1, 2020

	Network	Line Connection	Transformation Connection	Total
Rates Revenue Requirement (Excl. Foregone Revenue) ($M)	$951.0	$181.6	$453.2	$1,585.8
Annualized Foregone Revenue ($M)*	$78.5	($34.0)	$10.8	$55.3
Total Rates Revenue Requirement (Incl. Foregone Revenue) ($M)	**$1,029.6**	**$147.6**	**$464.0**	**$1,641.1**

*As per Exhibit 2.3.3

Appendix A

2020 Uniform Transmission Rates

and

Revenue Disbursement Allocators

EB-2019-0296

Decision and Rate Order

Updated: December 19, 2019

2020 Interim Uniform Transmission Rates and Revenue Disbursement Allocators

(for Period January 1, 2020 to December 31, 2020)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,548,772	$1,134,471	$2,304,848	$7,988,092
CNPI	$2,646,322	$659,997	$1,340,883	$4,647,201
H1N SSM	$23,244,093	$5,797,114	$11,777,707	$40,818,914
H1N	$905,380,457	$225,803,345	$458,753,350	$1,589,937,152
B2MLP	$32,464,151	$0	$0	$32,464,151
NRLP	$9,389,914	$0	$0	$9,389,914
All Transmitters	$977,673,709	$233,394,927	$474,176,788	$1,685,245,424

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	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
NRLP	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)	**3.92**	**0.97**	**2.33**	
FNEI Allocation Factor	**0.00465**	**0.00486**	**0.00486**	
CNPI Allocation Factor	**0.00271**	**0.00283**	**0.00283**	
H1N SSM Allocation Factor	**0.02377**	**0.02484**	**0.02484**	
H1N Allocation Factor	**0.92606**	**0.96747**	**0.96747**	
B2MLP Allocation Factor	**0.03321**	**0.00000**	**0.00000**	
NRLP Allocatio Factor	**0.00960**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

** The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-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: H1N SSM 2020 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0266 dated December 17, 2019.

Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision ond Order on Interim Rates EB-2019-0082 dated December 10, 2019.

Note 5: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.

Note 6: Calculated data in shaded cells.

Note 7: NRLP 2020 Interim Revenue Requirement per OEB Decision and Order EB-2018-0275 December 19, 2019

Appendix B

2020 Uniform Transmission Rate Schedules

EB-2019-0296

Decision and Rate Order

Updated: December 19, 2019

2020 ONTARIO INTERIM UNIFORM TRANSMISSION RATE

SCHEDULES EB-2019-0296

The rate schedules contained herein shall be implemented as of January 1, 2020

Issued: December 19, 2019
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) ofOntario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(G) EMBEDDED GENERATION The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generation are obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO- administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand [1,2]	**3.92**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand [1,3]	**0.97**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand [1,3,4]	**2.33**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:
1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

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

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Uniform Transmission Rates and Revenue Disbursement Allocators (Including Annualized 2020 Foregone Revenue)
Effective January 1, 2020 to December 31, 2020
Implementation on July 1, 2020

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,011,412	$718,221	$2,258,459	$7,988,092
CNPI	$2,915,470	$417,837	$1,313,895	$4,647,201
H1N SSM	$25,608,169	$3,670,089	$11,540,657	$40,818,914
H1N	$1,029,555,235	$147,552,881	$463,982,548	$1,641,090,663
B2MLP	$32,464,151	$0	$0	$32,464,151
NRLP	$9,389,914	$0	$0	$9,389,914
All Transmitters	$1,104,944,351	$152,359,027	$479,095,558	$1,736,398,935

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	235,252.608	228,852.936	195,027.487	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	239,504.148	232,385.678	196,285.037	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**4.61**	**0.66**	**2.44**	
FNEI Allocation Factor	**0.00454**	**0.00471**	**0.00471**	
CNPI Allocation Factor	**0.00264**	**0.00274**	**0.00274**	
H1N SSM Allocation Factor	**0.02318**	**0.02409**	**0.02409**	
H1N Allocation Factor	**0.93176**	**0.96846**	**0.96846**	
B2MLP Allocation Factor	**0.02938**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.00850**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

* The sum of 12 monthly charge determinants for the year.

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-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: H1N SSM 2020 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0266 dated December 17, 2019.
Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2019-0082, issued April 23, 2020, as per Exhibit 2.4
Note 5: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.
Note 6: NRLP 2020 Interim Revenue Requirement per OEB Decision and Order EB-2018-0275 December 19, 2019.
Note 7: Calculated data in shaded cells.

Filed: 2020-05-28
EB-2019-0082
Draft Rate Order
Exhibit 2.6.2
Page 1 of 6

2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2020-xxxx

The rate schedules contained herein shall be implemented as of July 1, 2020

Issued: Month, 2020
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) of Ontario.

(B) TRANSMISSION SYSTEM CODE The transmission service provided under these rate schedules is in accordance with the Transmission System Code (Code) issued by the Ontario Energy Board (OEB). The Code sets out the requirements, standards, terms and conditions of the transmitter's obligation to offer to connect to, and maintain the operation of, the transmission system. The Code also sets out the requirements, standards, terms and conditions under which a Transmission Customer may connect to, and remain connected to, the transmission system. The Code stipulates that a transmitter shall connect new customers, and continue to offer transmission services to existing customers, subject to a Connection Agreement between the customer and a transmitter.

(C) TRANSMISSION DELIVERY POINT The Transmission Delivery Point is defined as the transformation station, owned by a transmission company or by the Transmission Customer, which steps down the voltage from above 50 kV to below 50 kV and which connects the customer to the transmission system. The demand registered by two or more meters at any one delivery point shall be aggregated for the purpose of assessing transmission charges at that delivery point if the corresponding distribution feeders from that delivery point, or the plants taking power from that delivery point, are owned by the same entity within the meaning of Ontario's *Business Corporations Act*. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV.

(D) TRANSMISSION SERVICE POOLS The transmission facilities owned by the licenced transmission companies are categorized into three functional pools. The transmission lines that are used for the common benefit of all customers are categorized as Network Lines and the corresponding terminating facilities are Network Stations. These facilities make up the Network Pool. The transformation station facilities that step down the voltage from above 50 kV to below 50 kV are categorized as the Transformation Connection Pool. Other electrical facilities (i.e. that are neither Network nor Transformation) are categorized as the Line Connection Pool. All PTS customers incur charges based on the Network Service Rate (PTS-N) of Rate Schedule PTS. The PTS customers that utilize transformation connection assets owned by a licenced transmission company also incur charges based on the Transformation Connection Service Rate (PTS-T). The customer demand supplied from a transmission delivery point will not incur transformation connection service charges if a customer fully owns all transformation connection assets associated with that transmission delivery point. The PTS customers utilize lines owned by a licenced transmission company to connect to Network Station(s) also incur charges based on the Line Connection Service Rate (PTS- L). The customer demand supplied from a transmission delivery point will not incur line connection service charges if a customer fully owns all line connection assets connecting that delivery point to a Network Station. Similarly, the customer demand will not incur line connection service charges for demand at a transmission delivery point located at a Network Station.

(E) MARKET RULES The IESO will provide transmission service utilizing the facilities owned by the licenced transmission companies in Ontario in accordance with the Market Rules. The Market Rules and appropriate Market Manuals define the procedures and processes under which the transmission service is provided in real or operating time (on an hourly basis) as well as service billing and settlement processes for transmission service charges based on rate schedules contained herein.

(F) METERING REQUIREMENTS In accordance with Market Rules and the Transmission System Code, the transmission service charges payable by Transmission Customers shall be collected by the IESO. The IESO will utilize Registered Wholesale Meters and a Metering Registry in order to calculate the monthly transmission service charges payable by the Transmission Customers. Every Transmission Customer shall ensure that each metering installation in respect of which the customer has an obligation to pay transmission service charges arising from the Rate Schedule PTS shall satisfy the Wholesale Metering requirements and associated obligations specified in Chapter 6 of the Market Rules, including the appendices therein, whether or not the subject meter installation is required for settlement purposes in the IESO-administered energy market. A meter installation required for the settlement of charges in the IESO-administered that energy market may be used for the settlement of transmission service charges. The Transmission Customer shall provide to the IESO data required to maintain the information for the Registered Wholesale Meters and the Metering Registry pertaining to the metering installations with respect to which the Transmission Customers have an obligation to pay transmission charges in accordance with Rate Schedule PTS. The Metering Registry for metering installations required for the calculation of transmission charges shall be maintained in accordance with Chapter 6 of the Market Rules. The Transmission Customers, or Transmission Customer Agents if designated by the Transmission Customers, associated with each Transmission Delivery Point will be identified as Metered Market Participants within the IESO's Metering Registry. The metering data recorded in the Metering Registry shall be used as the basis for the calculation of transmission charges on the settlement statement for the Transmission Customers identified as the Metered Market Participants for each Transmission Delivery Point. The Metering Registry for metering installations required for calculation of transmission charges shall also indicate whether or not the demand associated with specific Transmission Delivery Point(s) to which a Transmission Customer is connected attracts Line and/or Transformation Connection Service Charges. This information shall be consistent with the Connection Agreement between the Transmission Customer and the licenced Transmission Company that connects the customer to the IESO-Controlled Grid.

(**G) EMBEDDED GENERATION** The Transmission Customers shall ensure conformance of Registered Wholesale Meters in accordance with Chapter 6 of Market Rules, including Metering Registry obligations, with respect to metering installations for embedded generation that is located behind the metering installation that measures the net demand taken from the transmission system if (a) the required approvals for such generationare obtained after October 30, 1998; and (b) the generator unit rating is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation ; and (c) the Transmission Delivery Point through which the generator is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments approved after October 30, 1998, to a generator unit that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation. The term renewable generation refers to a facility that generates electricity from the following sources: wind, solar, Biomass, Bio-oil, Bio-gas, landfill gas, or water. Accordingly, the distributors that are Transmission Customers shall ensure that connection agreements between them and the generators, load customers, and embedded distributors connected to their distribution system have provisions requiring the Transmission Customer to satisfy the requirements for Registered Wholesale Meters and Metering Registry for such embedded generation even if the subject embedded generator(s) do not participate in the IESO-administered energy markets.

(H) EMBEDDED CONNECTION POINT In accordance with Chapter 6 of the Market Rules, the IESO may permit a Metered Market Participant, as defined in the Market Rules, to register a metering installation that is located at the embedded connection point for the purpose of recording transactions in the IESO-administered markets. (The Market Rules define an embedded connection point as a point of connection between load or generation facility and distribution system). In special situations, a metering installation at the embedded connection point that is used to settle energy market charges may also be used to settle transmission service charges, if there is no metering installation at the point of connection of a distribution feeder to the Transmission Delivery Point. In above situations: •The Transmission Customer may utilize the metering installation at the embedded connection point, including all embedded generation and load connected to that point, to satisfy the requirements described in Section (F) above provided that the same metering installation is also used to satisfy the requirement for energy transactions in the IESO- administered market. •The Transmission Customer shall provide the Metering Registry information for the metering installation at the embedded connection point, including all embedded generation and load connected to that point, in accordance with the requirements described in Section (F) above so that the IESO can calculate the monthly transmission service charges payable by the Transmission Customer.

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

The Provincial Transmission Service (PTS) is applicable to all Transmission Customers in Ontario who own facilities that are directly connected to the transmission system in Ontario and that withdraw electricity from this system.

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand [1,2]	**4.61**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand [1,3]	**0.66**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand [1,3,4]	**2.44**

The rates quoted above shall be subject to adjustments with the approval of the Ontario Energy Board.

Notes:

1 The demand (MW) for the purpose of this rate schedule is measured as the energy consumed during the clock hour, on a "Per Transmission Delivery Point" basis. The billing demand supplied from the transmission system shall be adjusted for losses, as appropriate, to the Transmission Point of Settlement, which shall be the high voltage side of the transformer that steps down the voltage from above 50 kV to below 50 kV at the Transmission Delivery Point.

2. The Network Service Billing Demand is defined as the higher of (a) customer coincident peak demand (MW) in the hour of the month when the total hourly demand of all PTS customers is highest for the month, and (b) 85 % of the customer peak demand in any hour during the peak period 7 AM to 7 PM (local time) on weekdays, excluding the holidays as defined by IESO. The peak period hours will be between 0700 hours to 1900 hours Eastern Standard Time during winter (i.e. during standard time) and 0600 hours to 1800 hours Eastern Standard Time during summer (i.e. during daylight savings time), in conformance with the meter time standard used by the IMO settlement systems.

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

4. The Transformation Connection rate includes recovery for OEB approved Low Voltage Switchgear compensation for Toronto Hydro Electric System Limited and Hydro Ottawa Limited.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code, in particular the Connection Agreement as per Appendix 1 of the Transmission System Code, and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to services provided under this Rate Schedule.

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

The Export Transmission Service is applicable for the use of the transmission system in Ontario to deliver electrical energy to locations external to the Province of Ontario, irrespective of whether this energy is supplied from generating sources within or outside Ontario.

	Hourly Rate
Export Transmission Service Rate (ETS):	$1.85 / MWh

The ETS rate shall be applied to the export transactions in the Interchange Schedule Data as per the Market Rules for Ontario's Electricity Market. The ETS rate shall be subject to adjustments with the approval of the Ontario Energy Board.

TERMS AND CONDITIONS OF SERVICE:

The attached Terms and Conditions pertaining to the Transmission Rate Schedules, the relevant provisions of the Transmission System Code and the Market Rules for the Ontario Electricity Market shall apply, as contemplated therein, to service provided under this Rate Schedule.

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

Low Voltage Switchgear (LVSG) Credit 2020-2022

Year	Charge Determinant (MW)	Transformation Pool Revenue Requirement Before LVSG Credit ($M)	Rate Before LVSG Credit ($/kw/month)	Total Annual NCP Demand for Toronto Hydro and Hydro Ottawa (MW)	LVS Proportion (%)	Final Annual LVSG Credit ($M)
	(Note 1)	*(Note 2)*		*(Note 3)*	*(Note 4)*	
	(A)	(B)	(C) = (B)/(A)	(D)	(E)	(F) = (C)x(D)x(E)
2020	195,027	$438.7	$2.25	33,781	19.0%	$14.4
2021	194,724	$457.9	$2.35	33,586	19.0%	$15.0
2022	194,599	$477.7	$2.45	33,497	19.0%	$15.6

Note 1: Per Exhibit 2.1
Note 2: Equals Total Revenue Requirement for Transformation Connection Pool less Non-Rate Revenues allocated to Transformation Connection Pool, as per information in Exhibit 2.2
Note 3: Sum of Toronto Hydro and Hydro Ottawa total annual NCP Demand consistent with OEB approved load forecast for 2020 to 2022.
Note 4: Per EB-2019-0082, Exhibit I1, Tab 1, Schedule 3, page 7

Hydro One Networks Inc.

Implementation of Decision with Reasons on EB-2019-0082

2020-2022 Bill Impacts on Transmission-Connected and Distribution-Connected Customers

Table 1: Average Bill Impacts on Transmission and Distribution-connected Customers

	2019*	2020	2021	2022
Rates Revenue Requirement ($M)	$1,552.3	$1,585.8	$1,656.6	$1,729.1
% Increase in Rates RR over prior year		2.2%	4.5%	4.4%
% Impact of load forecast change		3.8%	0.2%	0.1%
Net Impact on Average Transmission Rates		6.0%	4.6%	4.4%
Transmission as a % of Tx-connected customer's Total Bill		7.4%	7.4%	7.4%
Estimated Average Bill impact		0.4%	0.3%	0.3%
Transmission as a % of Dx-connected customer's Total Bill		6.2%	6.2%	6.2%
Estimated Average Bill impact		0.4%	0.3%	0.3%

** 2019 rates revenue requirement as per the OEB's Decision and Order for Hydro One's 2019 Transmission Revenue Requirement application (EB-2018-0130), issued on 25th April, 2019.*

Table 2: Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1,800 kWh**
Total Bill as of May 1, 2018[1]	$83.40	$121.75	$236.81
RTSR included in 2017 R1 Customer's Bill (based on 2016 UTR)	$4.78	$8.96	$21.50
Estimated 2019 Monthly RTSR [2]	$5.10	$9.56	$22.95
2019 increase in Monthly Bill	**$0.13**	**$0.24**	**$0.58**
2019 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR [3]	$5.39	$10.10	$24.24
2020 increase in Monthly Bill	**$0.29**	**$0.54**	**$1.29**
2020 increase as a % of total bill	*0.3%*	*0.4%*	*0.5%*
Estimated 2021 Monthly RTSR [3]	$5.62	$10.54	$25.30
2021 increase in Monthly Bill	**$0.24**	**$0.44**	**$1.06**
2021 increase as a % of total bill	*0.3%*	*0.4%*	*0.4%*
Estimated 2022 Monthly RTSR [3]	$5.86	$10.99	$26.37
2022 increase in Monthly Bill	**$0.24**	**$0.44**	**$1.06**
2022 increase as a % of total bill	*0.3%*	*0.4%*	*0.4%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 1.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 1, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

Table 3: General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$198.93	$367.73	$2,562.20
RTSR included in 2017 GSe Customer's Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2019 Monthly RTSR [2]	$11.35	$22.69	$170.21
2019 increase in Monthly Bill	**$0.29**	**$0.58**	**$4.32**
2019 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2020 Monthly RTSR [3]	$11.99	$23.97	$179.81
2020 increase in Monthly Bill	**$0.64**	**$1.28**	**$9.60**
2020 increase as a % of total bill	*0.3%*	*0.3%*	*0.4%*
Estimated 2021 Monthly RTSR [3]	$12.51	$25.02	$187.68
2021 increase in Monthly Bill	**$0.52**	**$1.05**	**$7.87**
2021 increase as a % of total bill	*0.3%*	*0.3%*	*0.3%*
Estimated 2022 Monthly RTSR [3]	$13.04	$26.08	$195.57
2022 increase in Monthly Bill	**$0.53**	**$1.05**	**$7.89**
2022 increase as a % of total bill	*0.3%*	*0.3%*	*0.3%*

[1]Total bill including HST, based on time-of-use commodity prices effective May 1, 2018 and 2017 distribution rates approved per Distribution Rate Order EB-2016-0081 (includes impacts of all components of the Fair Hydro Plan).

[2]2019 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017 and 2018 and Hydro One's 2019 rates revenue requirement as shown in Table 1.

[3]The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 1, adjusted for Hydro One's revenue disbursement allocator per 2019 Interim UTR Order (EB-2018-0326).

HYDRO ONE NETWORKS INC.
PROPOSED WHOLESALE METER SERVICE AND EXIT FEE SCHEDULE

	HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

This fee schedule is applicable to the *metered market participants** that are transmission customers of Hydro One Networks ("Networks") and to *metered market participants* that are customers of a Local Distribution Company ("LDC") that is connected to the transmission system owned by Networks.

* The terms and acronyms that are italicized in this schedule have the meanings ascribed thereto in Chapter 11 of the Market Rules for the Ontario Electricity Market.

a) Fee for Wholesale Meter Service

The *metered market participant* in respect of a *load facility* (including customers of an LDC) shall be required to pay an annual fee of $7,900 for each *meter point* that is under the transitional arrangement for a *metering installation* in accordance with Section 3.2 of Chapter 6 of the Market Rules for the Ontario Electricity Market.

This Wholesale Meter Service annual fee shall remain in place until all the remaining meter points exit the transitional arrangement.

b) Fee for Exit from Transitional Arrangement

The *metered market participant* in respect of a *load facility* (including customers of an LDC) or a *generation facility* may exit from the transitional arrangement for a *metering installation* upon payment of a one-time exit fee of $ 5,200 per *meter point*.

TRANSMISSION ACCOUNTING ORDER – INTEGRATED SYSTEM OPERATING CENTER

Hydro One Transmission proposes the establishment of a new "Integrated System Operating Center ("ISOC") Asymmetrical Variance Account" to record the difference between the revenue requirement associated with the ISOC's actual costs placed in-service and the revenue requirement associated with the forecasted cost of the ISOC. This account will be asymmetrical to the benefit of ratepayers - if the revenue requirement at the actual cost is lower than the revenue requirement at the forecast cost, Hydro One Transmission will return the difference to ratepayers. The balance captured in this ISOC variance account shall be adjusted from the calculation of the Transmission Capital In-Service Additions variance account to ensure the revenue requirement impact is only captured in one of the accounts.

The account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "ISOC Asymmetrical Variance Account" effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
DR 4050	Revenue Adjustment
CR 2405	Other Regulatory Liabilities – Sub-Account "ISOC Asymmetrical Variance Account"

Initial entry to record the difference between the revenue requirement associated with the

ISOC's actual costs placed in-service and the revenue requirement associated with the forecasted cost of the ISOC.

DR 6035	Other Interest Expense
CR 2405	Other Regulatory Liabilities – Sub-Account "ISOC Asymmetrical Variance Account"

To record interest improvement on the principal balance of the ISOC Asymmetrical Variance Account.

TRANSMISSION ACCOUNTING ORDER – DEPRECIATION EXPENSE (ASSET REMOVAL COSTS) ASYMMETRICAL CUMULATIVE VARIANCE ACCOUNT

Hydro One Transmission proposes the establishment of a new "Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account" to record the difference between the revenue requirement associated with asset removal costs forecasts that have been included in the proposed depreciation expenses for 2020-2022 and actual asset removal costs incurred in each of the test years, net of tax. The account calculation will be cumulative by the end of 2022 – the account balance will be brought forward for disposition in a future rate application in the event that there is an over collection on a cumulative basis over the 2020 to 2022 period. This account will be asymmetrical to the benefit of ratepayers - if the actual asset removal costs are lower than the forecasted asset removal costs, Hydro One Transmission will return the difference to ratepayers.

The account will be established as Account 2405, Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account" effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
DR 4305	Regulatory Debits
CR 2405	Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account"

Initial entry to record the difference between actual asset removal costs and forecasted asset removal costs.

DR 6035	Other Interest Expense
CR 2405	Other Regulatory Liabilities – Sub-Account "Asset Removal Costs Asymmetrical Cumulative Variance Account"

To record interest improvement on the principal balance of the Asset Removal Costs Asymmetrical Cumulative Variance Account.

TRANSMISSION ACCOUNTING ORDER – CAPITAL IN-SERVICE ADDITIONS VARIANCE ACCOUNT

Hydro One Transmission proposes the establishment of a modified "Capital In-Service Additions Variance Account ("CISVA")" to record the differences between the revenue requirement associated with the actual capital in-service additions for 2020 through 2022 and the revenue requirement associated with the Board-approved capital in-service additions for those years.

Hydro One Transmission will track the impact on revenue requirement of any capital in-service additions that are 98% of the Board-approved amount or less on a combined basis for test years 2020 and 2021 at the end of 2021, including any 2019 variances, in consideration of the potential impacts of the COVID-19 pandemic on current year in-service additions. In other words, Hydro One requests that 2020 and 2021 be considered cumulatively at the end of 2021, rather than performing a calculation in each year of 2020 and 2021. This will incentivize Hydro One Transmission to ensure that capital in-service additions targets are met by the end of 2021 in the event there are uncontrollable impacts arising from the COVID-19 pandemic that cause it to defer in-servicing assets from 2020 to 2021. For cumulative in-service additions that are 98% of the Board-approved level or less, the associated revenue requirement impact will be computed and reported in 2021 and 2022 in this account, net of the revenue requirement associated with variances in in-service additions resulting from verifiable productivity gains. The approval of the 2020 rate base figure in this Application would inherently include the 2019 in-service additions forecast; therefore, Hydro One is proposing that for 2021 calculation, the account should consider 2019, 2020, and 2021 in-service additions on a cumulative basis.

At the end of the three-year term, Hydro One Transmission will seek disposition of the account balance. The variance account will be asymmetrical; should the cumulative in-service additions in years 2020-2021 recorded in 2021, and in years 2022 exceed 98% of the cumulative Board-approved amount, no entry will be made in the variance account.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Capital In-Service Additions Variance Account" effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
DR 4305	Regulatory Debits
CR 1508	Other Regulatory Assets – Sub-Account "Capital In-Service Additions Variance Account"

Initial entry to record the differences between the revenue requirement associated with the actual capital in-service additions and the revenue requirement associated with the Board-approved in-service capital additions.

DR 6035	Other Interest Expense
CR 1508	Other Regulatory Assets – Sub-Account "Capital In-Service Additions Variance Account"

To record interest improvement on principal balance of the Capital In-Service Additions Variance Account.

TRANSMISSION ACCOUNTING ORDER – FOREGONE TRANSMISSION REVENUE DEFERRAL ACCOUNT

Hydro One Transmission proposes the establishment of a new “Foregone Transmission Revenue Deferral Account” to record the difference between revenue earned by Hydro One Transmission under interim Uniform Transmission Rates (UTR), and the revenues that would have been received under the approved UTR based on OEB-approved 2020 rates revenue requirement and load forecast (“Foregone Revenue”). The account will capture the Foregone Revenue from January 1, 2020 to the date when the approved rates revenue requirement and load forecast are reflected in an update to current interim UTR rates.

The account will be established as Account 1508, Other Regulatory Assets – Sub- Account “Foregone Transmission Revenue Deferral Account” effective January 1, 2020. Hydro One Transmission will record interest on the balance in the sub-account using the interest rates set by the Board. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this variance account.

USofA #	Account Description
CR 4110	Transmission Services Revenue
DR 1508	Other Regulatory Assets – Sub account “Foregone Transmission Revenue Deferral Account”

Initial entry to record Foregone Revenue.

CR 6035	Other Interest Expense
DR 1508	Other Regulatory Assets – Sub account “Foregone Transmission Revenue Deferral Account”

To record interest improvement on the principal balance of the Foregone Transmission Revenue Deferral Account.