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

BY COURIER

October 26, 2018

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

Dear Ms. Walli,

EB-2018-0130 - Hydro One Networks Inc.'s 2019 Transmission Revenue Requirement Application and Evidence Filing

Hydro One Networks Inc. ("Hydro One") hereby submits its evidence in support of an application for its 2019 transmission revenue requirement. An electronic copy of the evidence has been submitted using the Ontario Energy Board's Regulatory Electronic Submission System along with the two paper copies attached to this letter.

Hydro One's points of contact for service of documents associated with the Application are listed in Exhibit A, Tab 2, Schedule 1.

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea
Encls.

DISCLAIMER

Forward-Looking Statements and Information

This application may contain "forward-looking information" within the meaning of applicable securities laws. Such information includes, but is not limited to: expectations regarding developments in the statutory and operating framework for electricity distribution and transmission in Ontario including changes to codes, licenses, rates, rate orders, cost recovery, rates of return, rate structures and revenue requirements in both our transmission and distribution businesses and the timing of decisions from the OEB; and statements regarding future capital expenditures and our investment plans. Words such as "expect," "anticipate," "intend," "attempt," "may," "plan," "will", "can", "believe," "seek," "estimate," and variations of such words and similar expressions are intended to identify such forward-looking information. These statements are not guarantees of future performance or actions and involve assumptions and risks and uncertainties that are difficult to predict. Therefore, actual outcomes and results may differ materially from what is expressed, implied or forecasted in such forward-looking information. Some of the factors that could cause actual results or outcomes to differ materially from the results expressed, implied or forecasted by such forward-looking information, including some of the assumptions used in making such statements, are discussed more fully in Hydro One's filings with the securities regulatory authorities in Canada, which are available on SEDAR at www.sedar.com. Hydro One does not intend, and it disclaims any obligation, to update any forward-looking information, except as required by law.

EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A	1	1		Exhibit List
A	2	1		Application
A	2	1	1	Certification of Evidence
A	3	1		Executive Summary
A	4	1		Revenue Cap Index
A	5	1		Bill 2 Adjustments
A	6	1		Deferral and Variance Accounts
A	6	1	1	Accounting Order – OPEB Deferral Account
A	6	1	2	Accounting Order – RCI Differential Account
A	6	2		Continuity Schedule*
A	7	1		Rate Design
A	7	1	1	Approved 2018 Uniform Transmission Rates and Revenue Disbursement Allocators
A	7	1	2	Proposed 2019 Uniform Transmission Rates and Revenue Disbursement Allocators
A	7	1	3	Proposed 2019 Uniform Transmission Rates Schedules

* Indicates that Exhibit/Attachment has been provided in Excel format.

APPLICATION

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

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

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

2. This is an application for a Revenue Cap Index adjustment to determine Hydro One's 2019 revenue requirement.

3. Hydro One hereby applies to the Ontario Energy Board (the "Board"), pursuant to section 78 of the *Ontario Energy Board Act, 1998,* (the "OEB Act") as amended, for orders:

   a) Approving the proposed Revenue Cap Index adjustment to set Hydro One's transmission revenue requirement effective January 1, 2019, as described in Exhibit A, Tab 4, Schedule 1. Hydro One also asks that the OEB amend the Uniform Transmission Rates to allow for recovery of the proposed revenue requirement for 2019.

   b) Approving the disposal of regulatory assets outlined in Exhibit A, Tab 6, Schedule 1 with a total credit balance of $37.6 million which represents audited principal balances as at December 31, 2017, plus forecast interest accrued in 2018, less any amounts approved for disposition in 2018 by the OEB in the EB-2016-0160 proceeding for rate years 2017 and 2018. Hydro One seeks approval to refund this amount as an offset to its revenue requirement over a one-year period commencing January 1, 2019.

c) Amending the Accounting Order approved in EB-2017-0338 to allow the account to continue to apply until Hydro One's next rebasing.

d) Approving an Accounting Order to establish a variance account to track the revenue requirement impact of changes to Hydro One's proposed Inflation Factor and Productivity Factor in the current Application and the Inflation Factor and Productivity Factor established by the OEB in EB-2018-0218 to the extent there is a difference.

e) Approving such other items or amounts that may be requested by the Applicant in the course of this proceeding, and as may be granted by the OEB.

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

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

FORM OF HEARING REQUESTED

6. Given the limited scope and mechanistic nature of the Application, the Applicant requests that this Application be heard by way of a written hearing.

PROPOSED EFFECTIVE DATE

7. Hydro One asks that the OEB's rate orders be effective January 1, 2019. In order to address the possibility that the requested rate orders cannot be made effective by that time, the Applicant hereby requests an Interim Order making the Applicant's current transmission revenue requirement and the resulting charges effective on an interim basis as of January 1, 2019 and establishing an account to recover any differences between the interim rates and the final rates effective January 1, 2019 based on the OEB's Decision and Order herein.

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

CONTACT INFORMATION

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

a) The Applicant:

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

Address for personal service:	7th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Mailing Address:	7th Floor, South Tower 483 Bay Street Toronto, ON M5G 2P5
Telephone:	(416) 345-4373
Fax:	(416) 345-5395
Electronic access:	Regulatory@HydroOne.com

b) The Applicant's counsel:

Torys LLP

Address:	79 Wellington St. W, 30th Floor Box 270, TD South Tower Toronto ON M5K 1N2
Fax:	(416) 865-7380

Charles Keizer

Telephone:	(416) 865-7152
Electronic access:	ckeizer@torys.com

Crawford Smith

Telephone:	(416) 865-8209
Electronic access:	csmith@torys.com

DATED at Toronto, Ontario, this 26th day of October, 2018.

HYDRO ONE NETWORKS INC.

By its counsel,

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Charles Keizer, Torys LLP

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Crawford Smith, Torys LLP

CERTIFICATION OF EVIDENCE

TO: ONTARIO ENERGY BOARD

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

1. I am a senior officer of Hydro One;
2. This certificate is given pursuant to Chapter 1 of the Ontario Energy Board's *Filing Requirements for Electricity Transmission Applications* (last revised on February 11, 2016)*;* and
3. The evidence submitted in support of Hydro One's 2019 transmission revenue requirement application (EB-2018-0130) filed with the OEB is accurate, consistent and complete to the best of my knowledge.

DATED this 26th day of October, 2018.

Frank D'Andrea

FRANK D'ANDREA

EXECUTIVE SUMMARY

This Exhibit describes the scope and key aspects of Hydro One's application ("the Application"), including its proposed Revenue Cap Index ("RCI") approach to setting the 2019 transmission revenue requirement, effective January 1, 2019.

On March 16, 2018, the Ontario Energy Board ("OEB") advised Hydro One that rates for Hydro One's distribution and transmission businesses should be considered in a single application. To facilitate that outcome, the OEB indicated that it expected Hydro One to file a transmission revenue requirement application for a 4-year test period (2019-2022) in order to align the applications and test periods for future combined applications. On April 4, 2018 Hydro One filed a letter with the OEB indicating that it was considering the potential impact of the OEB's new expectation on Hydro One's then upcoming application, which Hydro One had expected to be a Custom IR application with a 5 year test period.

However, Hydro One experienced organizational changes in July and August, 2018, which included the appointment of a new Board of Directors. As a result, Hydro One is in the process of evaluating its transmission business plan. To permit this review to occur and to account for inflation as well as to adhere to the OEB's objective of a combined transmission and distribution application in the future, Hydro One proposes the following two step approach. First, this Application for a one-year mechanistic adjustment to Hydro One's 2019 revenue requirement. Second, in 2019, a 3-year Custom IR application with a 2020-2022 test period to allow alignment with the OEB's expectation that Hydro One file a single application for distribution rates and transmission revenue requirement for the period 2023 to 2027.

Consistent with the RCI approach to setting rates, this Application is mechanistic in nature. The directions arising from the OEB's decision in the 2017-2018 transmission rate proceeding (EB-2016-0160) will not be addressed in this Application as they are beyond the scope of the approvals sought. Instead, Hydro One will address those directions in its 2020-2022 Custom IR application.

The OEB's Price Cap IR regime for electricity distributors is well established. Although there are no standard rate-setting parameters regarding RCIs for electricity transmitters similar to the Price Cap IR, Hydro One has adopted the methodologies similar to those that were used under Price Cap IR, as set out in its benchmarking evidence in this Application.

While Hydro One proposes that this Application be approved with the inflation and productivity factors as filed, it recognizes that the same 3rd party benchmarking evidence underpinning the proposed RCI in this Application is currently before the OEB in the Hydro One Sault St. Marie proceeding (EB-2018-0218) and will be tested and considered by the OEB in that proceeding.

In the spirit of regulatory efficiency and to facilitate a timely effective date of January 1, 2019, Hydro One proposes it be bound in the current Application by the OEB's determination on inflation and productivity in the EB-2018-0218 proceeding. In so doing, Hydro One seeks approval to establish a variance account to track the revenue requirement impact of changes to Hydro One's proposed Inflation Factor and Productivity Factor in the current Application and the Inflation Factor and Productivity Factor established by the OEB in EB-2018-0218, to the extent there is a difference. Hydro One proposes to adopt in the Application, the inflation and productivity factors approved in that proceeding to allow for consistency in Hydro One's transmission businesses.

The foregoing would balance the outcomes of:

- allowing for a timely adjustment to Hydro One's transmission revenue requirement to accommodate for externally driven inflationary cost pressures, effective January 1, 2019;
- ensuring the RCI parameters are appropriately tested by the OEB and stakeholders;
- avoiding the re-testing of the same evidence that is already before the OEB in EB-2018-0218; and
- ensuring that customers and Hydro One are kept whole.

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

- the proposed RCI mechanism and parameters to be used for the determination of Hydro One's 2019 revenue requirement, to be effective January 1, 2019;
- a variance account to track the revenue requirement impact of differences between the proposed RCI parameters and the final values approved by the OEB in EB-2018-0218;
- disposition of regulatory accounts with total net credit balances of $37.6 million effective January 1, 2019, to be refunded over a one-year; and
- an update to the Accounting Order approved by the OEB in EB-2017-0338 allowing for the account to continue to apply until the effective date of Hydro One's next rebased revenue requirement.

The Application will result in an average impact on transmission rates of 2.6% and a total bill impact of 0.2% for a typical Residential (R1) customer consuming 750 kW per month and a total bill impact 0.1% for a typical energy-billed General Service (GS < 50 kW) customer consuming 2,000 kWh per month.

1.1 BILL 2, URGENT PRIORITIES ACT

On July 25, 2018, Bill 2, Urgent Priorities Act ("Bill 2") received Royal Assent. Among other things, Bill 2 amended the *Ontario Energy Board Act, 1998* requiring that "in approving just and reasonable rates for Hydro One Limited or any of its subsidiaries, the

Board shall not include any amount in respect of compensation paid to the Chief Executive Officer and executives” of Hydro One Limited.

As outlined in Exhibit A, Tab 5, Schedule 1, Hydro One has determined that its OEB-approved 2018 revenue requirement included $0.96 million in compensation related to executives, as defined by Bill 2. Hydro One notes that the OEB has established procedural steps for the consideration of the impact of Bill 2 in Hydro One’s current 2018-2022 Custom IR distribution rate application (EB-2017-0049).[1] The proposed Bill 2 adjustment in the current Application is on the same basis as Hydro One’s proposal in EB-2017-0049. Hydro One proposes to adopt the OEB’s direction from EB-2017-0049, as applicable to the circumstances of the Application, in the final Rate Order for this proceeding to ensure consistency between its transmission and distribution businesses. In the event that the OEB’s determination in EB-2017-0049 is not available prior to the proposed effective date for this Application, Hydro One proposes that the scope of its proposed RCI parameter variance account could be expanded to capture the revenue requirement impact of any OEB directions regarding the Bill 2 adjustments from EB-2017-0049, as well.

1.2 REVENUE CAP INDEX

Hydro One’s application is based on a Revenue Cap Incentive Rate-Setting (“IR”) approach in which revenue for the 2019 test year is equal to the revenue in year 2018 inflated by the RCI set out below. The proposed RCI and associated parameters are identical to those proposed by Hydro One in the current Hydro One Sault St. Marie

[1] Additional procedural steps were established in Procedural Order No. 9 of the EB-2017-0049 proceeding, issued on September 26, 2018.

proceeding (EB-2018-0218). Hydro One is proposing to use the RCI to inflate its 2018 OEB-approved revenue requirement, adjusted for the impacts of Bill 2 as described above.

The RCI is expressed as:

$$RCI = I - X$$

Where:

- "I" is the Inflation Factor, based on a custom weighted two-factor input price index.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.

In order to inform its RCI, Hydro One engaged Power System Engineering ("PSE") to conduct various benchmarking analyses. The PSE report was filed as Attachment 1 to Exhibit D, Tab 1, Schedule 1 in the Hydro One Sault St. Marie proceeding (EB-2018-0218) and will be tested as part of that proceeding.

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

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

The proposed weighting of 14% labour and 86% non-labour is derived from the analysis conducted by PSE in its study. Based on the most recent OEB-reported results, the Inflation Factor would be 1.2%. Hydro One's proposed Productivity Factor of 0% reflects the recommendations of the PSE report and is the sum of the Custom Industry Total Factor Productivity measure of 0% and a Custom Productivity Stretch Factor of 0%. Combined these factors result in an RCI of 1.2% for 2019.

As noted above, the proposed RCI and the PSE study are currently before the OEB in EB-2018-0218. Hydro One is not proposing that these matters be re-tested in this proceeding. Rather, Hydro One proposes that the Application be approved based on the proposed parameters and that a variance account be established to track any revenue requirement difference between the proposed RCI parameters and the final values that are approved by the OEB in EB-2018-0218, if needed.

1.3 DEFERRAL AND VARIANCE ACCOUNTS

Hydro One requests disposition of a $37.6 million credit balance in the regulatory accounts detailed in Table 1. Hydro One is requesting disposition of the actual audited Regulatory Account values as at December 31, 2017, plus forecast interest accrued in 2018, less any amounts approved for disposition in 2018 by the OEB in the EB-2016-0160 proceeding for rate years 2017 and 2018. Hydro One proposes to dispose of this balance as an offset to its revenue requirement over a one-year period, effective January 1, 2019.

Table 1 - Transmission Regulatory Accounts Requested for Disposition ($ Millions)

Description	Forecast Balance as at Dec 31, 2018
Excess Export Service Revenue	(6.5)
External Secondary Land Use Revenue	(16.0)
External Station Maintenance, E&CS and Other External Revenue	(2.1)
Tax Rate Changes	0.4
Rights Payments	1.6
Pension Cost Differential	(13.0)
Long-Term Transmission Future Corridor Acquisition and Development	0.0
LDC CDM Variance Account	(0.8)
External Revenue – Partnership Transmission Projects Account	(0.0)
OEB Cost Differential Account	(1.3)
Total Regulatory Accounts Seeking Disposition	**(37.6)**

Exhibit Reference: A-6-1.

In EB-2017-0338, the OEB approved an Accounting Order for an account to capture the financial impacts associated with a change to USGAAP accounting standards from the issuance of Accounting Standards Update (ASU) 2017-07, which related to the accounting for pension and other post-employment benefits (OPEB). As originally worded, the Accounting Order was approved to track the impact of the ASU 2017-07 until the time of Hydro One's next revenue requirement application. At the time of the decision, Hydro One expected to file a 4-year Custom IR rebasing application for 2019-2022. Hydro One is requesting approval for a modification to the Accounting Order approved in EB-2017-0338 that will allow the account to continue to track the impact of the ASU 2017-07 change until the time of Hydro One's next rebasing application.

Hydro One is also requesting approval of a variance account to track the revenue requirement difference between the proposed RCI parameters and the final parameters that will be approved by the OEB in the Hydro One Sault St. Marie proceeding currently before the OEB in the EB-2018-0218 proceeding. In the event that the OEB's determination in the EB-2017-0049 proceeding is not available prior to the proposed effective date for this Application, Hydro One proposes that the scope of variance account could be expanded to also capture the revenue requirement impact of any OEB directions regarding the Bill 2 adjustments from the EB-2017-0049 proceeding.

1.4 RATE DESIGN

Hydro One is proposing to inflate its 2018 OEB-approved total revenue requirement, as adjusted for the impacts of Bill 2, by the RCI. The revenue that is required to be collected through transmission rates (i.e. the rates revenue requirement) is based on this total revenue requirement, offset by other revenues as described in Exhibit A, Tab 7, Schedule 1.

The transmission charge determinants used to calculate the 2019 proposed Uniform Transmission Rates ("UTR") are the same as those approved in EB-2016-0160 for 2018 and Hydro One is proposing to use the OEB-approved 2018 split of the rates revenue requirement by rate pool to allocate the 2019 rates revenue requirement among the three transmission rate pools.

Table 2 provides the forecast UTRs for 2019. Full calculations are provided in Exhibit A, Tab 7, Schedule 1.

Table 2 - Forecast 2019 UTRs

	Uniform Transmission Rates ($/kW-Month)		
	Network	**Line Connection**	**Transformation Connection**
2018	$3.61	$0.95	$2.34
2019	$3.70	$0.97	$2.40

1.5 BILL IMPACTS

Table 3 shows the average 2019 bill impacts of the proposed changes in transmission rates revenue requirement for distribution connected and transmission connected customers. Further details regarding the calculation are provided in Exhibit A, Tab 7, Schedule 1.

Table 3 - Average Bill Impacts on Transmission and Distribution-connected Customers

Description	**2018**	**2019**
Rates Revenue Requirement ($M)	$1,510.7	$1,550.2
Net Impact on Average Transmission Rates		2.6%
Transmission as a % of Tx-connected customer's Total Bill		7.4%
Estimated Average Bill impact for a Tx-Connected Customer		0.2%
Transmission as a % of Dx-connected customer's Total Bill		6.2%
Estimated Average Bill impact for a Dx-Connected Customer		0.2%

The 2.6% increase in average transmission rates is driven by: (i) the proposed RCI adjustment to Hydro One's revenue requirement; and (ii) a reduction in the total credits to Hydro One's revenue requirement resulting from factors such as the disposition of deferral and variance accounts and the expiration of the $10.5 million credit for foregone revenue that resulted from the implementation of the OEB's decision in the EB-2016-

0160 proceeding. Hydro One's proposal to dispose of the $37.6 million credit balance in its deferral and variance accounts, detailed above, mitigates the impact of the cessation of the credit offsets that were approved in EB-2016-0160.

The total bill impact for a typical Hydro One medium density residential (R1) customer consuming 400 kWh, 750 kWh and 1,800 kWh per month is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed in Table 4.

Table 4 - Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1800 kWh**
Total Bill as of May 1, 2018[1]	$84.33	$123.51	$241.03
RTSR included in Total Bill (based on 2016 UTR)	$4.78	$8.96	$21.50
Estimated 2017 Monthly RTSR[2]	$4.74	$8.89	$21.33
2017 change in Monthly Bill	($0.04)	($0.07)	($0.16)
2017 change as a % of total bill	*0.0%*	*-0.1%*	*-0.1%*
Estimated 2018 Monthly RTSR[3]	$4.97	$9.32	$22.36
2018 change in Monthly Bill	$0.23	$0.43	$1.02
2018 change as a % of total bill	*0.3%*	*0.3%*	*0.4%*
Estimated 2019 Monthly RTSR[4]	$5.09	$9.55	$22.91
2019 change in Monthly Bill	**$0.12**	**$0.23**	**$0.55**
2019 change as a % of total bill	*0.1%*	*0.2%*	*0.2%*

[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 the Fair Hydro Plan).

[2]2017 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017.

[3]2018 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2018.

[4]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 5, adjusted for Hydro One's revenue disbursement allocator per approved 2018 UTRs.

The total bill impact for a typical Hydro One General Service Energy less than 50 kW ("GSe < 50 kW") customer consuming 1,000 kWh, 2,000 kWh and 15,000 kWh per month is determined based on the forecast increase in the customer's RTSR as detailed in Table 5.

Table 5 - Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$201.89	$373.66	$2,606.65
RTSR included in Total Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2017 Monthly RTSR[2]	$10.55	$21.10	$158.25
2017 change in Monthly Bill	($0.08)	($0.16)	($1.21)
2017 change as a % of total bill	*0.0%*	*0.0%*	*0.0%*
Estimated 2018 Monthly RTSR[3]	$11.06	$22.11	$165.85
2018 change in Monthly Bill	$0.51	$1.01	$7.60
2018 change as a % of total bill	*0.3%*	*0.3%*	*0.3%*
Estimated 2019 Monthly RTSR[4]	$11.33	$22.66	$169.94
2019 change in Monthly Bill	**$0.27**	**$0.54**	**$4.08**
2019 change as a % of total bill	*0.1%*	*0.1%*	*0.2%*

[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 the Fair Hydro Plan).
[2]2017 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017.
[3]2018 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2018.
[4]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 5, adjusted for Hydro One's revenue disbursement allocator per approved 2018 UTRs.

1.6 OTHER MATTERS

On June 7, 2018 in EB-2017-0049, Hydro One Distribution sent a letter to the OEB further to its report dated September 14, 2017 titled *Regulatory Treatment of Pension and Other Post-employment Benefits (OPEBs) Costs* (EB-2016-0040). The OEB determined that it would set rates for the recovery of pension and OPEB costs using the accrual method of accounting and directed utilities to establish a variance account to track the difference between the forecasted accrual amount in rates and actual cash payments made, with a carrying charge applied to the differential, or "reference amount". The OEB provided the option for alternative methods of calculating the differential to be proposed by utilities. Hydro One suggested that the issue could be considered in EB-2017-0049. In a subsequent letter, issued on June 27, 2018, the OEB indicated that the matter was an issue relevant to both Hydro One's Distribution and Transmission businesses and would therefore be best addressed in Hydro One's upcoming transmission filing.

At the time of the OEB's letter, Hydro One expected to file a 4-year Custom IR transmission revenue requirement application. As noted above, Hydro One's plans regarding future transmission applications have changed. Given the nature of the OPEB expense issue and the mechanistic nature of this Application, Hydro One proposes that the consideration of this issue be deferred until its next rebasing application for its transmission revenue requirement which is expected to be filed in early 2019 with a 2020-2022 test period.

REVENUE CAP INDEX

Hydro One's application is based on a Revenue Cap Incentive Rate-Setting ("IR") approach in which the revenue requirement for 2019 is equal to the revenue requirement in year 2018, adjusted for the impacts of Bill 2 as outlined in Exhibit A, Tab 5, Schedule 1, inflated by the Revenue Cap Index ("RCI") set out below. The 2018 OEB approved revenue requirement reflects Hydro One's most recent rebasing of costs.

While Hydro One proposes that this Application be approved with the inflation and productivity factors as filed, Hydro One acknowledges that the same 3rd party benchmarking evidence underpinning the proposed RCI in this Application is currently before the OEB in the Hydro One Sault St. Marie proceeding (EB-2018-0218) and will be tested and considered by the OEB in that proceeding.

Hydro One proposes it be bound in the current Application by the OEB's determination on inflation and productivity in the EB-2018-0218 proceeding and, in so doing, Hydro One seeks approval to establish a variance account to track the revenue requirement impact of changes to Hydro One's proposed Inflation Factor and Productivity Factor in the current Application and the Inflation Factor and Productivity Factor established by the OEB in EB-2018-0218 to the extent there is a difference. Hydro One's proposes to adopt in the Application, the inflation and productivity factors approved in that proceeding to allow for consistency in Hydro One's transmission businesses.

The RCI includes an industry-specific inflation factor and two custom productivity factors. Consistent with the OEB's Renewed Regulatory Framework ("RRF"), these productivity factors are explicitly included in the rate adjustment mechanism and provide an incentive for Hydro One to achieve capital and OM&A productivity improvements.

Similar to the Price Cap Index used to adjusted distribution rates for electricity distributors, the RCI is expressed as:

$$RCI = I - X$$

Where:

- "I" is the Inflation Factor, based on a custom weighted two-factor input price index.
- "X" is the Productivity Factor that is equal to the sum of Hydro One's Custom Industry Total Factor Productivity measure and Hydro One's Custom Productivity Stretch Factor.

In order to inform its RCI, Hydro One engaged Power System Engineering ("PSE") to conduct various benchmarking analyses. The PSE report was filed as Attachment 1 to Exhibit D, Tab 1, Schedule 1 in the Hydro One Sault St. Marie proceeding (EB-2018-0218) and will be tested as part of that proceeding.

The PSE study was initially commissioned in support of a Custom IR filing covering a 4-year test period (2019 through 2022). The study includes some elements which are no longer relevant. These elements are the discussion regarding a Capital Factor and a forward-looking analysis which assessed Hydro One's forecast cost performance over a 4-year test period under a potential transmission system plan that is currently being re-evaluated by Hydro One. The forward-looking analysis may no longer reflect Hydro One's future total costs. That said, the historical analysis provided by PSE remains valid and relevant.

1.1 INFLATION FACTOR

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

- 86% of the annual percentage change in Canada's GDP-IPI (FDD) as reported by Statistics Canada; and

- 14% of the annual percentage change in the Average Weekly Earnings for workers in Ontario, as reported by Statistics Canada.

The proposed weighting of 14% labour and 86% non-labour is supported by the recommendation provided by PSE in the study provided in EB-2018-0218.

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

Given the similarities between the distribution and transmission businesses, Hydro One believes that it is appropriate to apply the same input price indices that are used to set the Inflation Factor for electricity distributors in Ontario to its transmission business. Hydro One notes its proposal is consistent with the OEB's recent decision which approved the use of the same input price indices in setting payment amounts for Ontario Power Generation's hydroelectric facilities (EB-2016-0152).

The latest annual percent change for the GDP-IPI and the Average Weekly Earnings for Workers in Ontario was released by the OEB on November 23, 2017 for use in applications for rates effective in 2018. The derivation of Hydro One's proposed Inflation Factor is shown in Table 1 below.

Table 1 - Derivation of Inflation Factor

	Non-Labour							Labour			Resultant Value - Annual Growth for the 2-factor IPI
	GDP-IPI (FDD) - National							AWE - All Employees - Ontario			
Year	Q1	Q2	Q3	Q4	Annual	Annual % Change (A)	Weight (B)	Annual	Annual % Change (C)	Weight (D)	Annual % Change ([A*B]+[C*D])
2015	114.6	115	115.7	116.1	115.35			962.94			
2016	116.4	116.3	116.8	117.5	116.75	1.2%	86%	973.56	1.1%	14%	1.2%

Hydro One has used the Inflation Factor of 1.2% derived above, on a pro-forma basis in its RCI calculation for the purpose of this Application. The Inflation Factor will be updated at the time of the rate order based on the methodology above to reflect the actual annual percent changes for each index that are made available by the OEB when it sets the Inflation Factor for distributors for 2019 rates.

1.2 PRODUCTIVITY FACTOR

The Productivity Factor (“X”) is equal to the sum of Hydro One’s Custom Industry Total Factor Productivity measure and Hydro One’s Custom Productivity Stretch Factor. Hydro One engaged PSE to undertake a study of the total factor productivity (“TFP”) trend for the electricity transmission industry and to undertake an econometric total cost benchmarking (“TCB”) study of Hydro One’s total transmission costs in order to recommend a Custom Productivity Stretch Factor.

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

PSE's study determined an electricity transmission industry TFP of -1.71%. Despite the negative industry TFP, PSE proposed a Custom Industry Total Productivity Factor of 0% consistent with the OEB's decision in EB-2010-0379.

PSE recommended a Custom Productivity Stretch Factor of 0%. In PSE's TCB analysis, Hydro One's projected total costs were determined to be approximately 27.3% below benchmark over the 2014-2016 period. Consistent with the approach under the OEB's 4th generation IRM, PSE recommended a stretch factor of 0%. This recommendation was based on Hydro One's strong cost performance and the adoption of 0% for Hydro One's Custom Industry Total Productivity Factor. PSE's rationale is further explained in its study which was filed as Exhibit D, Tab 1, Schedule 1 in the EB-2018-0160 proceeding.

BILL 2 ADJUSTMENTS

On July 25th, 2018 Bill 2, Urgent Priorities Act, 2018 ("Bill 2") received Royal Assent. Schedule 1 of Bill 2, defined as the Hydro One Accountability Act 2018, included amendments to the *Ontario Energy Board Act, 1998* ("OEB Act") placing limits on the amount of compensation paid to Hydro One's executives that could be included by the OEB in approving just and reasonable rates for Hydro One Limited or any of its subsidiaries.[1]

This Exhibit outlines the amount of executive compensation, subject to Bill 2, that is currently recovered through rates as part of the 2018 revenue requirement approved in EB-2016-0160. In order to comply with the requirements of Bill 2, Hydro One proposes that an adjustment of $0.96 million should be made to its approved 2018 revenue requirement to remove executive compensation, before applying the Revenue Cap Index described in Exhibit A, Tab 4, Schedule 1.

The proposed Bill 2 adjustment in the current Application is on the same basis as Hydro One's proposal in its 2018-2022 Custom IR distribution rate application (EB-2017-0049). Hydro One's intent is that its proposed Bill 2 adjustment will be applied consistently for both its distribution and transmission businesses. As outlined in Exhibit A, Tab 6, Schedule 1, Hydro One has proposed a variance account to track the revenue requirement impact of the OEB's determination on inflation and productivity in EB-2018-0218 to the extent that there is a difference between the proposals in this Application. In the event that the OEB's determination in EB-2017-0049 is not available prior to the proposed

[1] Hydro One's corporate organization chart was provided in Exhibit A, Tab 5, Schedule 1 of EB-2016-0160.

effective date for this Application, Hydro One proposes that the scope of its proposed variance account could be expanded to capture any differences in Bill 2 adjustments arising from EB-2017-0049, as well. Hydro One notes that any differences are likely to be below the materiality threshold of $3 million established in Chapter 2 of the OEB's *Filing Requirements for Transmission Revenue Requirement Applications*, however, as the removal of these expenses is required by legislature Hydro One proposes to remove them regardless of materiality.

1. BILL 2 SUMMARY

Bill 2 added the following subsection to section 78 of the OEB Act:

> (5.0.2) In approving or fixing just and reasonable rates for Hydro One Limited or any of its subsidiaries, the Board shall not include any amount in respect of <u>compensation paid to the Chief Executive Officer and executives</u>, within the meaning of the Hydro One Accountability Act, 2018, <u>of Hydro One Limited</u>. [emphasis added]

Hydro One believes that the amendment to the OEB Act is intended to apply to the executives that are responsible for providing the high-level oversight and strategic direction of Hydro One rather than its day to day operations. The executives meeting that description form Hydro One's Executive Leadership Team (ELT).

As outlined in Hydro One's submission filed on October 26, 2018 in EB-2017-0049, the legislation applies to the three executive positions that are within Hydro One Limited (HOL). However, Hydro One proposes to remove from rate recovery all compensation related to the positions within its Executive Leadership Team (ELT) regardless of which corporate entity they are employed with. In EB-2017-0049, the OEB established a process to review and test Hydro One's submission. Hydro One does not intend to revisit the issue in this Application. Instead, Hydro One proposes to adopt the outcome of that proceeding and remove the relevant amounts of compensation from its transmission revenue requirement for those same employee positions determined in that proceeding to be subject to Bill 2.

For clarity, Hydro One's ELT is comprised of the President and Chief Executive Officer, Chief Financial Officer, Chief Operating Officer, EVP and Chief Corporate Development Officer, EVP and Chief Legal Counsel, EVP Customer Care and Corporate Affairs and SVP People and Culture, Health and Safety.

At the time of the EB-2016-0160 proceeding, some of these positions were identified with different titles or did not exist. Hydro One has identified the comparable positions at the time of the EB-2016-0160 proceeding. These positions include the CEO, CFO, Chief Operating Officer and EVP Strategic Planning, General Counsel, SVP Customer and Corporate Relations, EVP Customer Care and Corporate Affairs, and SVP People and Culture/Health, Safety and the Environment. Hydro One is proposing to remove the compensation amounts for those positions that is included in its 2018 revenue requirement.

2. OEB'S FINDINGS IN EB-2016-0160

In its Decision and Order in EB-2016-0160 ("the Decision"), the OEB reduced the level of compensation costs that were allowed for recovery through rates from the filed amounts.

The Decision made an OM&A reduction for compensation costs and indicated that its approved reductions to Hydro One's capitals budgets "will have some compensation reduction impact"[2] which Hydro One understands to mean that any identified reductions from the OEB applied to both the capital and OM&A portions of Hydro One's compensation costs. In other words, the indicated reductions were at an overall compensation cost level. Based on this fact, Hydro One's analysis in Table 1 below shows overall compensation costs.

The Decision primarily expressed concerns with two aspects of Hydro One's compensation costs. First, the Decision expressed concern that Hydro One's total compensation costs were trending further away from the market median reflected in a 3rd party study undertaken by Mercer.[3] The Mercer study indicated that Hydro One's compensation for its non-represented (i.e. management) employees was 2% above market median.[4]

Second, in the Decision, the OEB expressed concern over the increases to Hydro One's Corporate Management costs. Specifically, the OEB stated:

> The OEB is concerned that the difference between two amounts of approximately $10.5 million per year of Corporate Management Costs, incremental to those incurred before the transformation of the parent holding company, are being allocated for recovery from transmission and distribution ratepayers when the delivery of essential delivery services by Networks remains essentially as it was before that transformation. [5]

The OEB stated that Hydro One's holding company "should have greater responsibility

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[2] Pg. 57, the Decision.
[3] Pg. 57, the Decision.
[4] The Mercer Study was submitted December 5, 2016 as part of EB-2016-0160.
[5] Pg. 58-59, the Decision.

for the compensation amounts that relate to its transformation and its commitments to increase shareholder value."[6]

Hydro One has interpreted these findings to mean the amount of Corporate Management costs recovered in rates was to be reduced to the level approved prior to Hydro One's transformation to a publicly traded company. When asked to apply the Decision related to compensation to Hydro One's distribution application (EB-2017-0049), Hydro One put forward this position in its December 12, 2017 submission and reduced Corporate Management expenses to be recovered through distribution rates to its 2015 levels, plus inflation. Hydro One subsequently updated its evidence to reflect this change in its December 21, 2017 update.

On this basis, in respect to transmission revenue requirement, Hydro One submits the Corporate Management expenses recovered in rates were reduced to 2015 pre-IPO levels. This category of expenses included the CEO and CFO positions.

3. BILL 2 COMPENSATION COSTS IN 2018 REVENUE REQUIREMENT

In EB-2016-0160, the application included ELT related compensation costs of $3.8 million for 2018.[7] These amounts included $2.7 million attributable to the CEO and CFO with the remainder attributable to the remaining members of the ELT.

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[6] Pg. 58-59, the Decision.
[7] Undertaking J10.5 provided the total compensation of $8.3 million for non-represented employees in pay grades 1-4 (i.e. all VP-level roles and above). The ELT represented $3.8 million of that amount.

As outlined above, the decision adjusted Hydro One's originally filed cost forecasts such that ELT compensation amounts (both capital and OM&A) underpinning Hydro One's 2018 OEB approved revenue requirement currently reflect:

- reductions to "transformation-related" compensation costs for the CEO and CFO positions to pre-IPO levels[8], and
- executive compensation amounts for all executive positions reduced to median levels, as determined by the Mercer study.

Table 1 below shows the originally filed overall costs for Hydro One's ELT and the amounts embedded for rate recovery in Hydro One's 2018 revenue requirement. The costs for the CEO and CFO are shown separately from the rest of the ELT to illustrate the impacts of the two different reductions noted above. As shown in Table 1, the originally filed compensation costs for the CEO and CFO are reduced from $2.7 million to $0.8 million which reflects the transmission-allocated portion of the 2015 pre-IPO levels of compensation for those positions, adjusted for inflation. The costs for the remainder of Hydro One's ELT are reduced from $1.15 million to $1.13 million to reflect the results of the Mercer compensation benchmarking study which found that the compensation for MCP (i.e. management) positions was 2% above the market median.

[8] Note that the cost forecasts at the time of EB-2016-0160 proceeding did not include compensation for other transformation-related executive positions as there were no incumbents for those positions at the time the forecasts were developed.

Table 1 - ELT Compensation ($M)

Tx Allocated Costs	2018 Costs in Revenue Requirement	2018 Costs per OEB Decision	2018 Reductions Required to Ensure Bill 2 Compliance
CEO, CFO Compensation	2.7	0.8	-0.8
Other ELT Members	1.1	1.1	-1.1
Total ELT	**3.8**	**1.9**	**-1.9**
OM&A Comp		**0.9**	**-0.9**
Capital Comp		**1.0**	**-1.0**

As noted above, the OEB's findings made reductions on an overall basis to the OM&A and capital components of Hydro One's compensation costs. The costs in Table 1 reflect the total envelope compensation for the affected positions. In order to calculate the revenue requirement impact of the Bill 2 reductions, Hydro One has provided the OM&A and capital allocation of its ELT costs in Table 1 above. This allocation is based on the Black & Veatch methodology approved by the OEB in EB-2016-0160.

The revenue requirement impact of Bill 2 is the sum of a reduction of $0.9 million in OM&A and the revenue requirement associated with $1.0 million in capital and is summarized in Table 2 below.

Table 2 - Executive Compensation (Per OEB Decision)
Revenue Requirement Impact ($M)

OM&A	-0.93
Capital Related (Depreciation, Return on Capital, Income Tax)	-0.03
Total Revenue Requirement Impact	**-0.96**

In order to recognize the impact of Bill 2, Hydro One proposes to reduce its 2018 OEB-approved revenue requirement by the $0.96 million indicated in Table 2 prior to applying its proposed Revenue Cap Index adjustment for the purposes of deriving its 2019 transmission revenue requirement. Detailed calculations showing the derivation of Hydro One's 2019 revenue requirement are provided in Exhibit A, Tab 7, Schedule 1.

DEFERRAL AND VARIANCE ACCOUNTS

1. INTRODUCTION

The purpose of this Exhibit is to provide a description of Hydro One Transmission's regulatory accounts.

All of the regulatory accounts have been established consistent with the OEB's requirements as set out in the Accounting Procedures Handbook, subsequent OEB directions or pursuant to requests by Hydro One Transmission.

As discussed in Exhibit A, Tab 3, Schedule 1, Hydro One is asking for approval for an Accounting Order to establish a variance account to track the revenue requirement impact of changes to Hydro One's proposed Inflation Factor and Productivity Factor in the current Application and the Inflation Factor and Productivity Factor established by the OEB in EB-2018-0218 to the extent there is a difference.

Hydro One Transmission's outstanding deferral and variance accounts balances are summarized in Table 1 below:

Table 1 - Transmission Summary of Regulatory Accounts Balances
($ Million)

Description	Balance as at Dec 31, 2016	Balance as at Dec. 31, 2017	Balance as at Dec. 31, 2018
Total Regulatory Accounts Seeking Disposition	(127.2)	(84.4)	(37.6)
Total Regulatory Accounts Not Seeking Disposition	16.4	82.2	93.3
Total Regulatory Accounts	**(110.7)**	**(2.2)**	**55.7**

The forecast interest for 2018 is calculated by applying interest on the December 31, 2017 year-end audited principal balances less any amounts approved for disposition in 2018 using the OEB prescribed interest rate as per the Bankers' Acceptances three-month rate plus a spread of 25 basis points.

Information on each account and its balance is described in Section 2 and Section 3 of this Exhibit. A detailed continuity schedule is provided in live Excel format as Exhibit A, Tab 6, Schedule 2.

2. REGULATORY ACCOUNTS REQUESTED FOR DISPOSITION

The previous Transmission Decision (EB-2016-0160) approved or required the establishment/continuance of certain regulatory accounts. Table 2 below provides a list of the account balances requested for disposition as part of current 2019 transmission application.

Table 2 - Transmission Regulatory Accounts Requested for Disposition ($ Millions)

Description	USofA Account Ref.	Balance as at Dec 31, 2016	Balance as at Dec 31, 2017	Balance as at Dec 31, 2018 (Forecast)
Excess Export Service Revenue	2405	(28.3)	(15.6)	(6.5)
External Secondary Land Use Revenue	2405	(37.2)	(29.0)	(16.0)
External Station Maintenance, E&CS and Other External Revenue	2405	1.2	(1.7)	(2.1)
Tax Rate Changes	1592	0.1	0.5	0.4
Rights Payments	2405	(3.6)	0.1	1.6
Pension Cost Differential	2405	(3.9)	(9.8)	(13.0)
Long-Term Transmission Future Corridor Acquisition and Development	1508	0.6	0.3	0.0
LDC CDM and Demand Response Variance Account	1508	(54.1)	(27.5)	(0.8)
External Revenue – Partnership Transmission Projects Account	2405	(0.9)	(0.5)	(0.0)
OEB Cost Differential Account	1508	(1.1)	(1.2)	(1.3)
Total Regulatory Accounts Seeking Disposition		**(127.2)**	**(84.4)**	**(37.6)**

2.1 EXCESS EXPORT SERVICE REVENUE

This variance account was initially created in EB-2008-0272 and continued in EB-2016-0160. The OEB asked that Hydro One Transmission continue to capture any differences between forecast export service revenue approved by the OEB as part of 2017 and 2018 Transmission Rates and the actual export service revenue. As part of its decision, the OEB approved an Export Transmission Services (ETS) rate of $1.85/MWh and approved the Hydro One Transmission forecast at $39.2 million and $40.1 million in revenue for both 2017 and 2018 respectively. The balance in this account is reported to the OEB on a quarterly basis, consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $9.2 million balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast liability account balance of $6.5 million at the end of 2018.

2.2 EXTERNAL SECONDARY LAND USE REVENUE

This variance account was created in EB-2008-0272 and continued in EB-2016-0160. The OEB approved the continuance of this account asking that Hydro One Transmission capture any difference between the forecast external secondary land use revenues approved by the OEB, for each test year, as part of 2017 and 2018 transmission rates, and the actual secondary land use revenues for each of these years. The total external revenue, including secondary land use approved by the EB-2016-0160 Decision was $28.2 million and $28.5 million for 2017 and 2018 respectively. The portion related to secondary land use was $15.4 million and $15.6 million, respectively.

As at December 31, 2017, Hydro One Transmission had an excess external secondary land use revenue balance of $29.0 million, inclusive of accrued interest. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $13.4 million balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast liability account balance of $16.0 million at the end of 2018.

2.3 EXTERNAL STATION MAINTENANCE, E&CS AND OTHER EXTERNAL REVENUE

This variance account was created in EB-2008-0272 and continued in EB-2016-0160. The OEB asked that Hydro One Transmission continue to capture any differences between the OEB approved and actual net external station maintenance, engineering & construction services revenue and other external revenue. The total external revenue, including station maintenance, E&CS and other approved by the OEB in EB-2016-0160 was $28.2 million and $28.5 million for 2017 and 2018 respectively. The portion related to this account was $12.8 million and $12.9 million, respectively.

As at December 31, 2017, Hydro One Transmission had an excess external station maintenance, engineering and construction services and other external revenues balance of $1.7 million, inclusive of interest accrued. The balance in this account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, adjusted for the $0.4 million asset balance approved by the OEB for recovery in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast liability account balance of $2.1 million at the end of 2018.

2.4 TAX RATE CHANGE

This variance account was created as a result of the OEB's decision in EB-2006-0501. In EB-2016-0160, the OEB approved continuance of this account. The variance account captures the tax impact to Hydro One Transmission for the following items:

- differences that result from a legislative or regulatory change to the tax rates or rules; and
- differences that result from a change in, or a disclosure of, a new assessment or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

As at December 31, 2017, Hydro One Transmission had recognized an asset balance of $0.5 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $0.1 million balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast asset account balance of $0.4 million at the end of 2018.

2.5 RIGHTS PAYMENTS

This account was established based on the OEB's decision on Hydro One's Transmission Rates for 2011 and 2012 (EB-2010-0002). In the EB-2016-0160 Decision, the OEB approved continuance of this account. The OEB requested that Hydro One Transmission use a variance account to capture the difference between the forecast Rights Payments approved by the OEB for 2017 and 2018 Transmission Rates and the actual Rights Payments.

As at December 31, 2017, Hydro One Transmission has recorded an asset balance of $0.1 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, adjusted for the $1.5 million liability balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast asset account balance of $1.6 million at the end of 2018.

2.6 PENSION COST DIFFERENTIAL

This account tracks the difference between the OM&A pension cost estimates based on actuarial assessments approved in rates and the actual OM&A pension contributions. This account was established based on the OEB's decision on Hydro One Transmission's Rates for 2011 and 2012 (EB-2010-0002). In the EB-2016-0160 Decision, the OEB approved continuance of this account.

As at December 31, 2017, Hydro One Transmission has recognized a liability balance of $9.8 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements. Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, adjusted for the $3.0 million asset balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast liability account balance of $13.0 million at the end of 2018.

2.7 LONG-TERM TRANSMISSION FUTURE CORRIDOR ACQUISITION AND DEVELOPMENT

This deferral account approved during EB-2012-0031, records transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure. In order to ensure land corridor availability in near-urban areas, long term investment planning is required. The costs recorded in the account will be associated with land assessment work such as environmental studies and assessments, preliminary engineering studies, public and First Nations/Métis consultations, etc. The outcome of this work will be helpful in making determinations for new corridors and in setting aside the required land for planning purposes, thus ensuring its availability and affordability when the project proceeds.

As at December 31, 2017, Hydro One Transmission has recognized an asset balance of $0.3 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $0.3 million balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast asset account balance of $0.0 million at the end of 2018.

2.8 LOCAL DISTRIBUTION COMPANY ("LDC"), CONSERVATION AND DEMAND MANAGEMENT ("CDM"), AND DEMAND RESPONSE VARIANCE ACCOUNT

This account was established upon the Settlement Agreement approved by the OEB in EB-2012-0031 relating to Hydro One Transmission's 2013 and 2014 rates. The account tracks the difference between the forecast and actual CDM savings and Demand Response results of the Ontario Power Authority ("OPA")-funded, LDC-delivered programs for 2013 and 2014.

Hydro One used the annual results reported for the previous year by the OPA in September of 2014 and 2015 (for 2013 and 2014 results, respectively) and recorded to this variance account the difference between the actual CDM savings reported by the OPA and the forecast for 2013 and 2014. As at December 31, 2017, Hydro One Transmission has recognized a liability balance of $27.5 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $27.0 million balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast liability account balance of $0.8 million at the end of 2018.

As per the EB-2016-0160 Decision, Hydro One will maintain this account. Hydro One is currently developing the methodology and confirming data availability to allow recording variances in this account for 2017 onwards, and will propose the methodology for calculating the variance account amounts for review by the OEB and intervenors when Hydro One does request disposition of the variance account.

2.9 EXTERNAL REVENUE – PARTNERSHIP TRANSMISSION PROJECTS ACCOUNT

This account was approved by the OEB in EB-2012-0031 to allow Hydro One to record costs related to services provided by Hydro One employees to partnership companies, e.g. for work not directly to the benefit of Hydro One Transmission's ratepayers. These costs would be invoiced to the appropriate partnered company, and current transmission revenues equal to the invoiced amount would be recorded in this account for reduction of future transmission revenue requirements.

The balance in this account reflects the external revenue garnered as a result of the services provided to and on behalf of B2M LP to create the partnership. Most of these services were provided before B2M LP was an established entity and, as such, B2M LP had no ability to procure these services independently. B2M LP has subsequently paid Hydro One for the services rendered.

All amounts submitted to this account were provided on a cost basis in compliance with the Affiliate Relationship Code.

As at December 31, 2017, Hydro One Transmission has recognized a liability balance of $0.5 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date, reduced by the $0.4 million balance approved by the OEB for disposition in 2018 as part of the EB-2016-0160 Decision. This will result in a forecast liability account balance of $0.0 million at the end of 2018.

2.10 OEB COST DIFFERENTIAL ACCOUNT

In a letter from the OEB dated February 9, 2016, entitled “Revisions to the Ontario Energy OEB Cost Assessment Model”; the OEB authorized the establishment of Account 1508 ‘Other Regulatory Assets’, Sub-Account ‘OEB Cost Assessment Variance’.

The OEB authorized this account to record any material differences between the annual OEB cost assessment currently approved in rates and the actual OEB cost assessment amounts charged to Hydro One Transmission that will result from the application of the new cost assessment model effective April 1, 2016.

As at December 31, 2017, Hydro One Transmission has recorded a liability balance of $1.2 million, inclusive of interest accrued. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

Included in the balance submitted for approval is interest forecast through to December 31, 2018 to reflect carrying charges anticipated through to the proposed implementation date. This will result in a forecast liability account balance of $1.3 million at the end of 2018.

3. REGULATORY ACCOUNTS NOT BEING REQUESTED FOR DISPOSITION

The previous Transmission Decision (EB-2016-0160) approved or required the establishment/continuance of certain regulatory accounts. Table 3 below provides a list of the Transmission Regulatory Account balances not being requested for disposition as part of current 2019 transmission application.

Table 3 - Transmission Regulatory Accounts Not Being Requested for Disposition ($ Millions)

Description	US of A Account Ref.	Balance as at Dec 31, 2016	Balance as at Dec 31, 2017	Balance as at Dec 31, 2018 (Forecast)
East West Tie Deferral Account	1508	2.8	7.2	7.2
SECTR Deferral Account	1508	13.0	52.0	52.0
North West Bulk Transmission Deferral Account	1508	0.6	0.7	0.7
Transmission Forgone Revenue Deferral Account	1508	-	22.3	33.3
In-Service Capital Additions Variance Account	2405	0.0	0.0	0.0
Total Regulatory Accounts Not Seeking Disposition		**16.4**	**82.2**	**93.3**

3.1 EAST WEST TIE DEFERRAL ACCOUNT

This account was approved by the OEB on July 12, 2012 in Hydro One's application (EB-2012-0180) to establish a deferral account related to the East-West Tie Line proceeding (EB-2011-0140).

Hydro One was permitted to track costs in the EWTDA that relate to the following two categories:

1. costs incurred by Hydro One Transmission as incumbent transmitter to support the OEB through the designation process and to eventually facilitate the line's connection; and
2. expenditures incurred relating to preliminary engineering and other station connection work required to accommodate the East West Tie line.

At December 31, 2017 the account has a balance of $7.2 million. Hydro One is not requesting disposition of the balance in this account at this time. Carrying charges are not applied as this is currently a tracking account.

3.2 SECTR DEFERRAL ACCOUNT

This account was approved by the OEB in its decision on EB-2013-0421 relating to the Supply to Essex County Transmission Reinforcement project (SECTR project). This account was established to record all construction project costs relating to the SECTR project.

Hydro One is tracking costs relating to the SECTR project in this deferral account and at December 31, 2017 the account has a balance of $52.0 million. As this is a tracking account, Hydro One is not requesting disposition of the balance and carrying charges are not applied in this account.

3.3 NORTH WEST BULK TRANSMISSION DEFERRAL ACCOUNT

This account was approved by the OEB in EB-2014-0311, to establish a deferral account that records expenses relating to the North West Bulk Transmission Line ("NWBTL") associated with preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and Environmental Assessment preparation work. These costs would not qualify as Construction Work In Progress ("CWIP") and therefore would be OM&A costs. These OM&A costs were not included in the rates, thereby necessitating the establishment of this deferral account.

As at December 31, 2017, the account has a balance of $0.7 million. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements and carrying charges are applied to this account. With the inclusion of the NWBTL project in the 2017 Long-term Energy Plan, and recommendation to proceed with the project, Hydro One is not requesting the disposition of the balance in this account at this time and will do so once all preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and Environmental Assessment preparation costs related to the NWBTL have been incurred.

3.4 TRANSMISSION FORGONE REVENUE DEFERRAL ACCOUNT

Hydro One filed an accounting order with the OEB dated October 10, 2017 pursuant to the OEB's decision on Hydro One's transmissions revenue requirement for 2017 and 2018 in the EB-2016-0160 Proceeding. The accounting order established this deferral account for the purpose of recording the differences between revenue earned by Hydro One Transmission under the interim 2017 rates set at the 2016 Uniform Transmission Rates (UTR) level and the revenues that would have been received under the approved 2017 UTR based on the OEB-approved 2017 load forecast (i.e. foregone revenue). The accounting order was approved on November 9, 2017. In accordance with the approved accounting order, this account includes carrying charges. In addition, Hydro One Transmission will also book and has been booking into this account the difference between the revenue earned by Hydro One Transmission on the approved UTR in a given year and the revenue that would have been received based on Hydro One's position in its Motion to Review and Vary the Decision (EB-2017-0336).

As at December 31, 2017, the account has a balance of $22.3 million. A disposition of -$10.6 million of the balance at December 31, 2017 will be made through the 2018 UTR. The residual balance in this account represents the difference between the revenue earned by Hydro One Transmission on the approved UTR in a given year and the revenue that would have been received based on Hydro One's position noted in the Motion to Review and Vary the Decision. Hydro One will not seek disposition of this balance until the Motion to Review and Vary has been concluded. On August 31, 2018, the OEB granted the Motion with respect to the Future Tax Savings Determination and will return it to the original panel for further consideration.

3.5 IN SERVICE CAPITAL ADDITIONS VARIANCE ACCOUNT

As per the Settlement Agreement approved by the OEB, relating to Hydro One Transmission's 2015 and 2016 rates in EB-2014-0140, parties agreed that Hydro One would establish a net cumulative asymmetrical variance account for 2014, 2015 and 2016 to track the impact on revenue requirement of any in-service addition shortfall compared to OEB approved amounts, for disposition in a future rates application. The cumulative in service additions for those years exceeded the OEB-approved amount and therefore no entry was recorded.

As part of the EB-2016-0160 Decision, the OEB approved the continuance of this account to record the impact on 2017 and 2018 Transmission Revenue Requirement due to an actual amount for 2016 in-service additions that is less than $911.7 million, along with the difference between the 2017 and 2018 in-service additions embedded in 2017 and 2018 rate base and actual in-service additions in each of those years. As at December 31, 2017, the account has a balance of $0.0 million, as the cumulative in-service additions for 2017 including the impact on 2017 Transmission Revenue Requirement due to an actual amount for 2016 in-service additions that is less than $911.7 million exceeded the OEB approved amount. This account is reported to the OEB on a quarterly basis consistent with the OEB's Reporting and Record Keeping Requirements.

4. REGULATORY ACCOUNTS REQUESTED FOR CONTINUATION

Hydro One Transmission requests the continuation of the following regulatory accounts:

- Excess Export Service Revenue
- External Secondary Land Use Revenue
- External Station Maintenance, E&CS Revenue and Other External Revenue
- Tax Rate Changes
- Rights Payments
- Pension Cost Differential
- Long-Term Transmission Future Corridor Acquisition and Development Account
- LDC CDM and Demand Response Variance Account
- External Revenue – Partnership Transmission Projects Account
- OEB Cost Differential Account
- East West Tie Deferral Account
- Supply to Essex County Transmission Reinforcement (SECTR) Account

- North West Bulk Transmission Line (NWBTL) Account
- Transmission Foregone Revenue Deferral Account
- In-Service Capital Additions Variance Account
- Other Post-Employment Benefit (OPEB) Cost Deferral Account

4.1 EXCESS EXPORT SERVICE REVENUE

Hydro One Transmission proposes to continue to record the difference between the actual export service revenue for 2019 and the revenues approved by the OEB for 2018 as part of 2017-2018 transmission rates application.

4.2 EXTERNAL SECONDARY LAND USE REVENUE

Hydro One Transmission proposes to continue to record the difference between the actual External Secondary Land Use Revenues for 2019 and the revenues approved by the OEB for 2018 as part of 2017-2018 transmission rates application.

4.3 EXTERNAL STATION MAINTENANCE, E&CS REVENUE AND OTHER EXTERNAL REVENUE

Hydro One Transmission proposes to continue to record the difference between the actual External Station Maintenance, E&CS Revenues and Other External Revenues for 2019 against the estimated revenues approved by the OEB for 2018 as part of 2017-2018 transmission rates application.

4.4 TAX RATE CHANGES

Hydro One Transmission will continue to use this account to track the revenue requirement impact of legislative or regulatory changes to tax rates or rules compared to costs approved by the OEB as part of 2019 Transmission Rates.

4.5 RIGHTS PAYMENTS

Hydro One Transmission proposes to continue to record the difference between the actual Rights Payments paid for 2019 and those approved by the OEB for 2018 as part of 2017-2018 transmission rates application.

4.6 PENSION COSTS DIFFERENTIAL

Hydro One Transmission proposes to continue to record the difference between the actual pension costs for 2019 and the forecast pension costs approved by the OEB for 2018 as part of 2017-2018 transmission rates application.

4.7 LONG-TERM TRANSMISSION FUTURE CORRIDOR ACQUISITION AND DEVELOPMENT ACCOUNT

This deferral account records transmission planning and study costs associated with preliminary corridor routing considerations for new transmission infrastructure.
Hydro One Transmission proposes to continue to record the costs in this deferral account for 2019 and will seek its disposition in a future rates application.

4.8 LDC CDM AND DEMAND RESPONSE VARIANCE ACCOUNT

This account was established as part of the Settlement Agreement that pertained to 2013 and 2014 transmission rates. In Hydro One's 2015 and 2016 rates application, the parties accepted Hydro One's CDM forecast in the load forecast and did not request that Hydro One record any variance for 2015 and 2016. In the EB-2016-0160 Decision, the OEB directed Hydro one to continue recording a variance relating to 2017 and 2018 and noted that this account should not be closed as previously requested by Hydro One. As per the EB-2016-0160 Decision, Hydro One will maintain this account.

4.9 EXTERNAL REVENUE – PARTNERSHIP TRANSMISSION PROJECTS ACCOUNT

The intent of this deferral account is to record costs for services provided by Hydro One employees for work they are performing for partnership companies, whether partnered with Hydro One Networks Inc. or Hydro One Inc., working on competitive or other partnership transmission projects.

Hydro One has and will identify specific employees to work with partnership companies in which it has a vested interest. Hydro One will track employee time and any expenses and the resulting costs will be invoiced to the appropriate partner. The amount of invoiced costs will be recorded in the External Revenue Partnership Transmission Project Account for reduction to future revenue requirements.

4.10 OEB COST DIFFERENTIAL ACCOUNT

This account is a continuation of the account that was re-established per the OEB's letter dated February 9, 2016, entitled "Revisions to the Ontario Energy Board Cost Assessment Model". Hydro One Transmission proposes to continue to track variances in annual OEB assessment costs approved by the OEB for 2018 as part of 2017-2018 transmission rates application and the 2019 actual OEB cost assessment amounts charged to Hydro One Transmission.

4.11 EAST-WEST TIE DEFERRAL ACCOUNT

This account is a continuation of the account accepted in EB-2012-0031. However, following the EB-2016-0160 Decision, Hydro One has only continued the second category of the prior approved account whereby, as the incumbent transmitter, Hydro One will track costs for expenditures incurred relating to preliminary engineering and other station connection work required to accommodate the East West Tie line.

4.12 SUPPLY TO ESSEX COUNTY TRANSMISSION REINFORCEMENT (SECTR)

This account was approved by the OEB in EB-2013-0421 for the purpose of recording construction costs relating to the OEB-approved SECTR Project. Hydro One will continue to track costs associated with the SECTR project in this account.

4.13 NORTH WEST BULK TRANSMISSION LINE (NWBTL)

Hydro One proposes to continue the use of this account to record the expenses incurred for preliminary design/engineering, cost estimation, public engagement/consultation, routing and siting, and environmental assessment preparation work associated with the NWBTL Project before the costs can be recorded in transmission construction work in progress ("CWIP"). Hydro One did not include these costs in the revenue requirement request and will continue to record such expenses in this account in 2019.

4.14 TRANSMISSION FORGONE REVENUE DEFERRAL ACCOUNT

Hydro One filed an accounting order with the OEB (dated October 10, 2017) pursuant to the EB-2016-0160 Decision, which established this deferral account for the purpose of recording the differences between revenue earned by Hydro One Transmission under the interim 2017 rates set at the 2016 Uniform Transmission Rates (UTR) level and the revenues that would have been received under the approved 2017 UTR based on the OEB-approved 2017 load forecast (i.e. foregone revenue). The accounting order was approved on November 9, 2017. In addition, Hydro One Transmission will also book into this account the difference between the revenue earned by Hydro One Transmission on the OEB-approved UTR in a given year and the revenue that would have been received based on Hydro One's position in its Motion to Review and Vary the OEB's decision on Hydro One Transmission's 2017-2018 revenue requirements (EB-2017-0336). On August 31, 2018, the OEB granted the Motion with respect to the Future Tax Savings Determination and will return it to the original panel for further consideration. Hydro One proposes the continuation of this variance account.

4.15 IN SERVICE CAPITAL ADDITIONS VARIANCE ACCOUNT

Hydro One proposes the continuation of this variance account as the actual 2018 in-service additions are not currently available. In its next rebasing application, the balance of the account including 2018 revenue requirement impact will be brought forward for disposition.

4.16 OTHER POST-EMPLOYMENT (OPEB) COST DEFERRAL ACCOUNT (EB-2017-0338)

On November 2, 2017 Hydro One submitted its application for an accounting order establishing a deferral account to capture the financial impacts associated with a change to USGAAP accounting standards from the issuance of Accounting Standards Update (ASU) 2017-07, which related to the accounting for pension and OPEB (EB-2017-0338). Upon adoption of ASU 2017-07 on January 1, 2018, only the service cost component of the net periodic pension cost and net periodic post-retirement benefit cost is eligible for capitalization where applicable. As Hydro One currently accounts for pensions on a cash-basis, this change only impacts OPEBs. The proposed account will be used to record the net periodic post-retirement benefit cost other than service cost that would have been classified as capital prior to the adoption of ASU 2017-07.

On May 10, 2018, the OEB approved the establishment of the deferral account, effective January 1, 2018 until the effective date of Hydro One's next transmission revenue requirement.[1] In the deferral account, Hydro One records the OPEB cost previously capitalized but no longer allowed to be capitalized as per Accounting Standards Update 2017-07.

On June 7, 2018, the OEB approved Hydro One's accounting order,[2] directed the company to propose an approach to the disposition of the deferral account and suggested that it may also be appropriate to amend the calculation and treatment of interest

[1] EB-2017-0338, Decision and Order, Hydro One Networks Inc., Application for an Accounting Order approving the establishment of a deferral account (May 10, 2018)
[2] EB-2017-0338, Decision and Account Order, Hydro One Networks Inc., Application for an Accounting Order approving the establishment of a deferral account (June 7, 2018)

depending on the selected approach to the disposition of the deferral account. As originally worded, the Accounting Order was approved to track the impact of the ASU 2017-07 until the time of Hydro One's next revenue requirement application. At the time of the decision, Hydro One was expected to be filing a 4-year Custom IR rebasing application for 2019-2022.

Hydro One is requesting approval for a modification to the Accounting Order approved in EB-2017-0338 that will allow the account to continue to track the impact of the ASU 2017-07 change until the time of Hydro One's next rebasing application. In its next rebasing application, Hydro One plans to propose a methodology to dispose of the balance as requested by the OEB.

5. REGULATORY ACCOUNTS REQUESTED TO BE DISCONTINUED

Hydro One is not seeking to discontinue any deferral accounts.

6. NEW REGULATORY ACCOUNTS REQUESTED FOR APPROVAL

Hydro One seeks an Accounting Order to establish a variance account to track the revenue requirement impact of changes to Hydro One's proposed Inflation Factor and Productivity Factor in the current Application and the Inflation Factor and Productivity Factor established by the OEB in EB-2018-0218 to the extent there is a difference ("the Proposed Account"). Hydro One has provided an accounting order for the Proposed Account as Attachment 2 to this Exhibit.

Chapter 2 of the OEB's *Filing Requirements for Electricity Transmission Applications*, dated February 11, 2016 ("the Filing Requirements") require that applicants seeking an accounting order to establish a new variance account to meet three eligibility criteria: causation, materiality and prudence.

Causation

The Proposed Account will track the revenue requirement difference between the Inflation Factor and Productivity Factor proposed in this proceeding and the OEB's ultimate decision regarding those parameters in the EB-2018-0218 proceeding and therefore the amounts are clearly outside of the base upon which the revenue requirement in this Application is set.

Materiality

The Filing Requirements establish a materiality threshold of $3 million for Hydro One. As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One is proposing a Productivity Factor of 0% based on the sum of a Custom Productivity Stretch Factor of 0% and a Custom Industry Total Factor Productivity measure of 0%. The materiality of any potential balance in the Proposed Account would depend on the final parameters approved by the OEB in EB-2018-0218 and the degree to which they deviate from Hydro One's proposals. For example, stretch factors approved by the OEB for other Ontario utilities in other cases have typically ranged from 0% to 0.6%. For example in the event that the EB-2018-0218 proceeding found that a Productivity Factor of 0.3% were appropriate, the Proposed Account would have a balance of $4.9 million to be credited to customers which would be material.

Prudence

Any balance in the Proposed Account will arise as a result of an OEB decision and can thus be determined to have been reasonably and prudently incurred.

Based on the reasons above, Hydro One believes that the Proposed Account meets all criteria for the establishment of a variance account.

ACCOUNTING ENTRIES

OPEB COST DEFERRAL ACCOUNT

The OPEB Cost Deferral Account will record all elements of the net periodic benefit cost other than the service cost that would have been classified as capital prior to the adoption of ASU 2017-07.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account “OPEB Cost Deferral Account” effective January 1, 2018 until such time as the effective date of the next transmission rebasing application. Hydro One Transmission will record interest on any balance in the sub-account using the interest rates set by the OEB. Simple interest will be calculated on the opening monthly balance of the account until the balance is fully disposed.

The following outlines the proposed accounting entries for this account:

USofA #	**Account Description**
Dr: 1508	Other Regulatory Assets – Sub-Account “OPEB Cost Deferral Account”
Cr: 2055	Construction Work In Progress - Electric

To record the capitalized elements of the net periodic post-retirement benefit cost other than service cost.

USofA #	Account Description
Dr: 1508	Other Regulatory Assets – Sub-Account “OPEB Cost Deferral Account”
Cr: 6035	Other Interest Expense

To record interest improvement on the principal balance of the “OPEB Cost Deferral Account”.

ACCOUNTING ENTRIES
REVENUE CAP INDEX PARAMETERS DIFFERENTIAL ACCOUNT

Hydro One Networks Transmission proposes the establishment of a new "Revenue Cap Index Parameters Differential Account" to track the revenue requirement difference between the proposed revenue cap index (RCI) parameters as documented in Exhibit A, Tab 4, Schedule 1 in this Application[1], and the final values that are approved by the OEB in EB-2018-0218.

The account will be established as Account 1508, Other Regulatory Assets – Sub-Account "Revenue Cap Index Parameters Differential Account" effective January 1, 2019. Hydro One Networks Transmission will record interest on the balance in the sub-account using the prescribed 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 account:

USofA #	Account Description
DR./CR. 1508	Other Regulatory Assets – Sub-Account "Revenue Cap Index Parameters Differential Account"
DR./CR. 4110	Transmission Services Revenue

To record the revenue requirement difference between the proposed RCI parameters as documented in this Application and the final values that are approved by the OEB in EB-2018-0218.

[1] The RCI parameters are the Inflation Factor and Productivity Factor proposed in this Application.

USofA #	**Account Description**
DR./CR. 6035	Other Interest Expense
DR./CR. 1508	Other Regulatory Assets – Sub-Account "Revenue Cap Index Parameters Differential Account"

To record carrying charges on the principal balance of the "Revenue Cap Index Parameters Differential Account".

		2016								
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-16	Transactions Debit / (Credit) during 2016 excluding interest and adjustments 6	Board-Approved Disposition during 2016	Closing Principal Balances as of Dec 31-16 Adjusted for Dispositions	Opening Interest Amounts as of Jan-1-16	Interest Disposition during 2016 - instructed by Board	Interest Jan-1 to Dec-31-16	Closing Interest Balance as at Dec 31 - 16 balance adjusted for disposition during 2016	2016 total bal (for evidence)
Excess Export Service Revenue	2405	(40,131,449)	(9,746,763)	(22,414,720)	(27,463,492)	(1,483,557)	(1,044,254)	(376,875)	(816,178)	(28,279,670)
External Revenue - Secondary Land Use	2405	(43,619,074)	(10,468,592)	(17,689,438)	(36,398,227)	(1,274,070)	(824,293)	(388,941)	(838,718)	(37,236,945)
External Stations Maintenance, E&CS & Other External Revenue	2405	(496,944)	509,285	(1,118,104)	1,130,445	(55,624)	(136,605)	(54,933)	26,048	1,156,493
Tax Rate Changes	1592	950,170	-	785,229	164,941	(43,724)	(1,369)	6,491	(35,864)	129,077
Rights Payments	2405	(4,723,472)	(541,649)	(1,754,730)	(3,510,391)	(175,665)	(111,139)	(50,698)	(115,225)	(3,625,616)
Pension Costs Differential	2405	13,449,599	(9,827,903)	7,713,259	(4,091,564)	616,458	466,124	72,291	222,626	(3,868,938)
Long-Term Transmission Future Corridor Acquisition and Development	1508	675,349	4,226	68,391	611,184	8,474	1,624	7,109	13,959	625,143
CDM Adjustment	1508	(52,490,000)			(52,490,000)	(988,662)	-	(577,390)	(1,566,052)	(54,056,052)
Bruce x Milton	2405	(870,000)			(870,000)	(10,364)		(9,570)	(19,934)	(889,934)
OEB fees variance Account	1508		(1,106,087)		(1,106,087)	-		(3,652)	(3,652)	(1,109,739)
Total Transmission Regulatory Accounts for Disposition		**(127,255,820)**	**(31,177,483)**	**(34,410,112)**	**(124,023,191)**	**(3,406,735)**	**(1,649,913)**	**(1,376,168)**	**(3,132,990)**	**(127,156,181)**
East-West Tie Deferral Account (Tracking only)	1508	1,095,943	1,742,775	-	2,838,718	-	-	-	-	2,838,718
SECTR Deferral Account (Tracking only)	1508	561,849	12,456,466	-	13,018,315	-	-	-	-	13,018,315
North West Bulk	1508	-	620,693		620,693	-		3,226	3,226	623,920
TX Foregone Revenue	1508									
Total Transmission Accounts NOT requesting Disposition		**1,657,792**	**14,819,934**	**-**	**16,477,727**	**(0)**	**-**	**3,226**	**3,226**	**16,480,953**
Total Transmission Regulatory Accounts		**(125,598,028)**	**(16,357,549)**	**(34,410,112)**	**(107,545,465)**	**(3,406,735)**	**(1,649,913)**	**(1,372,942)**	**(3,129,764)**	**(110,675,228)**
					-	-		-	-	-

		2017								
Account Descriptions	Account Number	**Opening Principal Amounts as of Jan-1-17**	**Transactions Debit / (Credit) during 2017 excluding interest and adjustments 6**	**Board-Approved Disposition during 2017**	**Closing Principal Balances as of Dec 31-17 Adjusted for Dispositions**	**Opening Interest Amounts as of Jan-1-17**	**Interest Disposition during 2017 - instructed by Board**	**Interest Jan-1 to Dec-31-17**	**Closing Interest Balance as at Dec 31 - 17 balance adjusted for disposition during 2017**	**2017 total bal (for evidence)**
Excess Export Service Revenue	2405	(27,463,492)	3,773,868	(9,216,852)	(14,472,772)	(816,178)		(282,811)	(1,098,989)	(15,571,761)
External Revenue - Secondary Land Use	2405	(36,398,227)	(4,738,428)	(13,356,623)	(27,780,032)	(838,718)		(381,309)	(1,220,026)	(29,000,058)
External Stations Maintenance, E&CS & Other External Revenue	2405	1,130,445	(2,502,765)	351,369	(1,723,689)	26,048		16,944	42,992	(1,680,697)
Tax Rate Changes	1592	164,941	395,981	63,969	496,953	(35,864)		1,603	(34,261)	462,691
Rights Payments	2405	(3,510,391)	2,247,289	(1,513,465)	250,363	(115,225)		(33,761)	(148,985)	101,377
Pension Costs Differential	2405	(4,091,564)	(2,817,142)	2,989,383	(9,898,089)	222,626		(100,768)	121,858	(9,776,232)
Long-Term Transmission Future Corridor Acquisition and Development	1508	611,184		309,981	301,202	13,959		5,509	19,467	320,670
CDM Adjustment	1508	(52,490,000)		(26,991,283)	(25,498,717)	(1,566,052)		(470,909)	(2,036,961)	(27,535,678)
Bruce x Milton	2405	(870,000)		(444,358)	(425,642)	(19,934)		(7,823)	(27,757)	(453,399)
OEB fees variance Account	1508	(1,106,087)	(108,742)		(1,214,829)	(3,652)	-	(13,950)	(17,602)	(1,232,431)
Total Transmission Regulatory Accounts for Disposition		**(124,023,191)**	**(3,749,940)**	**(47,807,878)**	**(79,965,253)**	**(3,132,990)**	**-**	**(1,267,275)**	**(4,400,265)**	**(84,365,517)**
East-West Tie Deferral Account (Tracking only)	1508	2,838,718	4,356,047	-	7,194,765	-	-	-	-	7,194,765
SECTR Deferral Account (Tracking only)	1508	13,018,315	38,990,124	-	52,008,439	-	-	-	-	52,008,439
North West Bulk	1508	620,693	89,100		709,793	3,226	-	8,233	11,460	721,253
TX Foregone Revenue	1508		22,219,539		22,219,539	-	-	65,002	65,002	22,284,540
					-	-	-	-	-	-
Total Transmission Accounts NOT requesting Disposition		**16,477,727**	**65,654,810**	**-**	**82,132,536**	**3,226**	**-**	**73,235**	**76,461**	**82,208,997**
Total Transmission Regulatory Accounts		**(107,545,465)**	**61,904,870**	**(47,807,878)**	**2,167,284**	**(3,129,764)**	**-**	**(1,194,040)**	**(4,323,803)**	**(2,156,520)**
					-	-		-	-	-

		2018								
Account Descriptions	Account Number	**Opening Principal Amounts as of Jan-1-18**	**Transactions Debit / (Credit) during 2018 excluding interest and adjustments 6**	**Board-Approved Disposition during 2018**	**Closing Principal Balances as of Dec 31-18 Adjusted for Dispositions**	**Opening Interest Amounts as of Jan-1-18**	**Board-Approved Disposition during 2018**	**Projected Interest Jan-1 to Dec-31-18**	**Projected Interest Balance as at Dec 31 - 18 balance adjusted for disposition during 2018**	**2018 total bal (for evidence)**
Excess Export Service Revenue	2405	(14,472,772)	-	(8,499,877)	(5,972,895)	(1,098,989)	(716,975)	(190,400)	(572,415)	(6,545,310)
External Revenue - Secondary Land Use	2405	(27,780,032)	-	(12,573,013)	(15,207,019)	(1,220,026)	(783,610)	(400,317)	(836,733)	(16,043,752)
External Stations Maintenance, E&CS & Other External Revenue	2405	(1,723,689)	-	269,791	(1,993,480)	42,992	81,577	(34,616)	(73,201)	(2,066,681)
Tax Rate Changes	1592	496,953	-	100,972	395,981	(34,261)	(37,003)	7,794	10,536	406,517
Rights Payments	2405	250,363	-	(1,455,277)	1,705,639	(148,985)	(58,188)	18,215	(72,582)	1,633,057
Pension Costs Differential	2405	(9,898,089)	-	2,746,956	(12,645,045)	121,858	242,427	(209,933)	(330,502)	(12,975,548)
Long-Term Transmission Future Corridor Acquisition and Development	1508	301,202	-	296,976	4,226	19,467	13,005	2,844	9,306	13,533
CDM Adjustment	1508	(25,498,717)		(25,498,717)	-	(2,036,961)	(1,492,566)	(237,457)	(781,852)	(781,852)
Bruce x Milton	2405	(425,642)		(425,642)	-	(27,757)	(18,716)	(3,964)	(13,005)	(13,005)
OEB fees variance Account	1508	(1,214,829)		-	(1,214,829)	(17,602)	-	(22,626)	(40,228)	(1,255,057)
					-					
Total Transmission Regulatory Accounts for Disposition		**(79,965,253)**	**-**	**(45,037,830)**	**(34,927,422)**	**(4,400,265)**	**(2,770,048)**	**(1,070,459)**	**(2,700,676)**	**(37,628,098)**
East-West Tie Deferral Account (Tracking only)	1508	7,194,765	-	-	7,194,765	-	-	-	-	7,194,765
SECTR Deferral Account (Tracking only)	1508	52,008,439		-	52,008,439	-	-	-	-	52,008,439
North West Bulk	1508	709,793	-	-	709,793	11,460	-	13,220	24,679	734,473
TX Foregone Revenue	1508	22,219,539		10,571,073	32,790,612	65,002		512,282	577,284	33,367,896
		-		-	-	-	-	-	-	-
Total Transmission Accounts NOT requesting Disposition		**82,132,536**	**-**	**10,571,073**	**92,703,609**	**76,461**	**-**	**525,502**	**601,963**	**93,305,572**
Total Transmission Regulatory Accounts		**2,167,284**	**-**	**(34,466,757)**	**57,776,187**	**(4,323,803)**	**(2,770,048)**	**(544,957)**	**(2,098,713)**	**55,677,474**
					-	-		-	-	-

RATE DESIGN

1. SUMMARY OF METHODOLOGY

This exhibit describes the process followed by Hydro One to derive its 2019 transmission rates revenue requirement, and allocate it among the three transmission rate pools: Network, Line Connection, and Transformation Connection.

This schedule also sets out the draft Uniform Transmission Rates ("UTRs") for 2019 and the impact of Hydro One's proposed 2019 rates revenue requirement on transmission-connected and distribution-connected customers.

As discussed in Exhibit A, Tab 4, Schedule 1, Hydro One proposes to inflate its 2018 OEB-approved total revenue requirement, as adjusted for the impacts of Bill 2, by a Revenue Cap Index ("RCI") of 1.2%. Revenue that is required to be collected through transmission rates is based on this total revenue requirement, offset by "Other Revenues" consisting of: regulatory assets credit, external revenue, wholesale meter service ("WMS") revenue, export transmission service ("ETS") revenue, funding for low voltage switchgear ("LVSG") credit, and 2017 foregone revenue (applicable in 2018 only). Exhibit A, Tab 6, Schedule 1 describes the regulatory variance accounts Hydro One is proposing to clear in this application. The external revenue, WMS revenue and ETS revenue are kept at the 2018 OEB-approved values. The 2017 foregone revenue amount is removed for 2019. The LVSG credit is dependent on the revenue requirement assigned to the Transformation Connection pool, and so, Hydro One is proposing to increase the approved 2018 LVSG credit amounts by the RCI of 1.2%.

Transmission charge determinants used to calculate the 2019 proposed UTRs are the same as those approved in EB-2016-0160 for 2018.

1.1 REVENUE REQUIREMENT CALCULATION

Table 1 shows the derivation of Hydro One's 2019 transmission rates revenue requirement.

Table 1 - Derivation of 2019 Rates Revenue Requirement

	2018 Amounts	Proposed Adjustments for 2019	Proposed 2019 Amounts
Total Approved Revenue Requirement (excluding Bill 2 adjustments)	$1,623,777,363		
Bill 2 Adjustments	-$962,852		
Total Revenue Requirement (including Bill 2 adjustments)	$1,622,814,512	1.2%	$1,642,288,286
Deduct: External Revenue	-$28,500,000	Same as approved 2018 amount	-$28,500,000
Deduct: WMS Revenue	-$276,500	Same as approved 2018 amount	-$276,500
Deduct: Export Tx Service Revenue	-$40,050,000	Same as approved 2018 amount	-$40,050,000
Deduct: Regulatory Assets Credit	-$47,800,000	As per Exhibit A-6-1	-$37,590,000
Add: Foregone Revenue	-$10,571,073	Not Applicable	$0
Add: LVSG Credit	$14,129,893	1.2%	$14,299,452
Rates Revenue Requirement	**$1,510,709,683**[1]		**$1,550,171,238**

[1] $1,510.7M refers to 2018 Approved Rates Revenue Requirement. When adjusted for Bill 2 impact, the value is $1,509.7

1.2 REVENUE REQUIREMENT BY RATE POOL

As shown in Table 2, Hydro One proposes to use the OEB-approved 2018 split of rates revenue requirement by rate pool to allocate the 2019 rates revenue requirement among the three transmission rate pools.

Table 2 - 2019 Revenue Requirement by Rate Pool

	Total Rates Revenue Requirement	**Network Rate Pool**	**Line Connection Rate Pool**	**Transformation Connection Rate Pool**
2018	**$1,510,709,683**	$831,494,343	$219,267,431	$459,947,909
Percentage Split by Rate pool	*100%*	*55%*	*15%*	*30%*
2019	**$1,550,171,238**	$853,213,976	$224,994,961	$471,962,302

1.3 UNIFORM TRANSMISSION RATES (UTR)

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002 as per the Board's Decision in Proceeding RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Ontario UTR Schedule[2], which was effective on January 1, 2018, is filed as Attachment 1 to this Exhibit.

Since rates are established on a uniform basis, Hydro One's requested transmission rates revenue requirement for the 2019 test year contributes to the total revenue requirement to

[2] UTR schedule was approved in the OEB's Decision and Rate Order, EB-2017-0359, issued February 1, 2018.

be collected from the provincial UTRs. The revenue requirement for all the other transmitters in the province approved to participate in the UTRs must be added to that of Hydro One Transmission in order to determine the total transmission revenue requirement for the province for 2019.[3]

The total revenue requirement from all transmitters must be allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement allocated to each rate pool for the other transmitters is currently based on the proportions established for Hydro One Transmission, except for B2M Limited Partnership whose costs are 100% allocated to the Network rate pool given that all of its assets are used to provide Network services. Once the revenue requirement by rate pool has been established, rates are determined by applying the provincial charge determinants for each pool to the total revenue requirement for each pool. The provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the Board for each of the transmitters participating in the UTR.

Table 3 provides the approved 2018 UTRs and forecast UTRs for 2019. The forecast UTRs are calculated using the rates revenue requirement proposed for Hydro One Transmission in this application; while maintaining the values as approved by the Board in the 2018 UTR Order (under Proceeding EB-2017-0359) for all other transmitters. As previously indicated, the provincial charge determinants are the same as those approved by the Board in the 2018 UTR Order. The derivation of proposed 2019 UTRs is provided

[3] The other four transmitters currently included in the UTRs are Hydro One Networks Sault Ste. Marie (formerly Great Lakes Power Transmission Inc.), Canadian Niagara Power Inc., Five Nations Energy Inc., and B2M Limited Partnership.

in Attachment 2 and the respective rate schedule is provided in Attachment 3 to this Exhibit.

Table 3 - Forecast 2019 UTRs

	Uniform Transmission Rates ($/kW-Month)		
	Network	**Line Connection**	**Transformation Connection**
2018	$3.61	$0.95	$2.34
2019	$3.70	$0.97	$2.40

2. BILL IMPACTS

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. For the purpose of estimating the impact of proposed changes to 2019 transmission rates on an average customer's bill, the same approach approved in EB-2016-0160 has been adopted.

Table 4 shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

Table 4 - Estimated Transmission Cost as a Percentage of Total Electricity Market Costs

Cost Component	¢/kWh	Source
Commodity	11.55	IESO Monthly Market Report December 2017
Wholesale Market Service Charges	0.43	IESO Monthly Market Report December 2017
Wholesale Transmission Charges	1.01	IESO Monthly Market Report December 2017
Debt Retirement Charge	0.70	IESO Monthly Market Report December 2017
Distribution Service Charges	2.61	2017 Yearbook of Electricity Distributors
Total Cost	**16.30**	
Transmission as Percentage of Total Cost for Dx-connected customers		***6.2%***
Transmission as Percentage of Total Cost for Tx-connected customers		***7.4%***

The figures from Table 4 have been applied to the proposed increase in transmission rates revenue requirement in 2019 to establish average bill impacts as shown in Table 5.

Table 5 - Average Bill Impacts on Transmission and Distribution-connected Customers

Description	**2018**	**2019**
Rates Revenue Requirement ($M)	$1,510.7	$1,550.2
Net Impact on Average Transmission Rates		2.6%
Transmission as a % of Tx-connected customer's Total Bill		7.4%
Estimated Average Bill impact for a Tx-Connected Customer		0.2%
Transmission as a % of Dx-connected customer's Total Bill		6.2%
Estimated Average Bill impact for a Dx-Connected Customer		0.2%

The total bill impact for a typical Hydro One medium density residential (R1) customer consuming 400 kWh, 750 kWh and 1,800 kWh per month is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSRs") as detailed in Table 6.

Table 6 - Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	400 kWh	**750 kWh**	**1800 kWh**
Total Bill as of May 1, 2018[1]	$84.33	$123.51	$241.03
RTSR included in Total Bill (based on 2016 UTR)	$4.78	$8.96	$21.50
Estimated 2017 Monthly RTSR[2]	$4.74	$8.89	$21.33
2017 change in Monthly Bill	($0.04)	($0.07)	($0.16)
2017 change as a % of total bill	*0.0%*	*-0.1%*	*-0.1%*
Estimated 2018 Monthly RTSR[3]	$4.97	$9.32	$22.36
2018 change in Monthly Bill	$0.23	$0.43	$1.02
2018 change as a % of total bill	*0.3%*	*0.3%*	*0.4%*
Estimated 2019 Monthly RTSR[4]	$5.09	$9.55	$22.91
2019 change in Monthly Bill	**$0.12**	**$0.23**	**$0.55**
2019 change as a % of total bill	*0.1%*	*0.2%*	*0.2%*

[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 the Fair Hydro Plan).

[2]2017 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017.

[3]2018 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2018.

[4]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 5, adjusted for Hydro One's revenue disbursement allocator per approved 2018 UTRs.

The total bill impact for a typical Hydro One General Service Energy less than 50 kW ("GSe < 50 kW") customer consuming 1,000 kWh, 2,000 kWh and 15,000 kWh per month is determined based on the forecast increase in the customer's RTSRs as detailed in Table 7.

Table 7 - Typical General Service Energy less than 50 kW (GSe < 50 kW) Customer Bill Impacts

	GSe Customer Monthly Bill		
	1,000 kWh	**2,000 kWh**	**15,000 kWh**
Total Bill as of May 1, 2018[1]	$201.89	$373.66	$2,606.65
RTSR included in Total Bill (based on 2016 UTR)	$10.63	$21.26	$159.47
Estimated 2017 Monthly RTSR[2]	$10.55	$21.10	$158.25
2017 change in Monthly Bill	($0.08)	($0.16)	($1.21)
2017 change as a % of total bill	*0.0%*	*0.0%*	*0.0%*
Estimated 2018 Monthly RTSR[3]	$11.06	$22.11	$165.85
2018 change in Monthly Bill	$0.51	$1.01	$7.60
2018 change as a % of total bill	*0.3%*	*0.3%*	*0.3%*
Estimated 2019 Monthly RTSR[4]	$11.33	$22.66	$169.94
2019 change in Monthly Bill	**$0.27**	**$0.54**	**$4.08**
2019 change as a % of total bill	*0.1%*	*0.1%*	*0.2%*

[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 the Fair Hydro Plan).

[2]2017 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2017.

[3]2018 Monthly RTSR is an estimated value that incorporates the impacts of changes in UTR in 2018.

[4]The impact on RTSR is assumed to be the net impact on average Transmission rates, as per Table 5, adjusted for Hydro One's revenue disbursement allocator per approved 2018 UTRs.

Appendix A

2018 Uniform Transmission Rates

and

Revenue Disbursement Allocators

EB-2017-0359

Decision and Rate Order

February 1, 2018

2018 Interim Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2018 to December 31, 2018)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,408,935	$1,426,550	$2,991,661	$9,827,155
CNPI	$2,557,819	$674,504	$1,414,878	$4,647,201
H1N SSM	$22,327,484	$5,887,821	$12,350,631	$40,565,936
H1N	$831,494,343	$219,267,431	$459,947,909	$1,510,709,683
B2MLP	$37,500,000	$0	$0	$37,500,000
All Transmitters	$899,288,581	$227,256,306	$476,705,079	$1,603,249,975

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	
GLPT	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	3.61	0.95	2.34	
FNEI Allocation Factor	0.00601	0.00628	0.00628	
CNPI Allocation Factor	0.00284	0.00297	0.00297	
GLPT Allocation Factor	0.02483	0.02591	0.02591	
H1N Allocation Factor	0.92462	0.96484	0.96484	
B2MLP Allocation Factor	0.04170	0.00000	0.00000	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2016-0231 dated January 18, 2018.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015.

Note 3: H1N SSM 2017 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2016-0356, issued September 28, 2017. F

Note 4: H1N Rates Revenue Requirement (including 2017 Foregone Revenue) per OEB Decision EB-2016-0160 dated December 20, 2017.

Note 5: H1N Charge Determinants per OEB Decision EB-2016-0160, issued November 23, 2017.

Note 6: B2M LP 2018 Revenue Requirement per OEB Decision and Order EB-2015-0026 dated December 29, 2015.

Note 7: Calculated data in shaded cells.

Appendix B

2018 Uniform Transmission Rate Schedules

EB-2017-0359

Decision and Rate Order

February 1, 2018

2018 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2016-0160
EB-2017-0359

The rate schedules contained herein are interim and shall be effective and implemented as of January 1, 2018.

Issued: February 1, 2018
Ontario Energy Board

EFFECTIVE DATE:	BOARD ORDER:	REPLACING BOARD ORDER:	Page 1 of 6
January 1, 2018	EB-2017-0359	EB 2017-0280 November 23, 2017	Ontario Uniform Transmission Rate Schedule

TERMS AND CONDITIONS

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

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

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

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

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

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

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

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

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

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

	Interim Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	
$ Per kW of Network Billing Demand [1,2]	3.61
Line Connection Service Rate (PTS-L):	
$ Per kW of Line Connection Billing Demand [1,3]	0.95
Transformation Connection Service Rate (PTS-T):	
$ Per kW of Transformation Connection Billing Demand [1,3,4]	2.34

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.

2019 Draft Uniform Transmission Rates and Revenue Disbursement Allocators

(Effective for period January 1, 2019 to December 31, 2019)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$5,408,864	$1,426,333	$2,991,958	$9,827,155
CNPI	$2,557,819	$674,504	$1,414,878	$4,647,201
H1N SSM	$22,327,484	$5,887,821	$12,350,631	$40,565,936
H1N	$853,213,976	$224,994,961	$471,962,302	$1,550,171,238
B2MLP	$37,500,000	$0	$0	$37,500,000
All Transmitters	$921,008,143	$232,983,619	$488,719,769	$1,642,711,530

Transmitter	Total Annual Charge Determinants (MW)**			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
H1N SSM	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,175.697	240,480.984	203,767.673	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.70**	**0.97**	**2.40**	
FNEI Allocation Factor	**0.00587**	**0.00612**	**0.00612**	
CNPI Allocation Factor	**0.00278**	**0.00290**	**0.00290**	
H1N SSM Allocation Factor	**0.02424**	**0.02527**	**0.02527**	
H1N Allocation Factor	**0.92639**	**0.96571**	**0.96571**	
B2MLP Allocation Factor	**0.04072**	**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 (including 2017 Foregone Revenue) and Charge Determinant Order EB-2016-0231 dated January 18, 2018.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 with approved 2016 order under EB-2015-0354, issued January 14, 2016 and confirmed on November 9, 2017 (EB-2016-0160).

Note 3: H1N SSM 2017 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2016-0356, issued September 28, 2017.

Note 4: H1N Rates Revenue Requirement per Exhibit A, Tab 7, Schedule 1.

Note 5: H1N Charge Determinants per OEB Decision EB-2016-0160, issued November 23, 2017

Note 6: B2M LP 2018 Revenue Requirement per OEB Decision and Order EB-2015-0026 dated December 29, 2015.

Note 7: Calculated data in shaded cells.

Filed: 2018-10-26
EB-2018-0130
Exhibit A-7-1
Attachment 3
Page 1 of 6

2019 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2018-0130

The rate schedules contained herein shall be effective January 1, 2019

Issued: Month, Year
Ontario Energy Board

TERMS AND CONDITIONS

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

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

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

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

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

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

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

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

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

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

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N): $ Per kW of Network Billing Demand [1,2]	**3.70**
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]	**2.40**

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.