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Vice President, Regulatory Affairs & Chief Risk Officer

BY EMAIL, COURIER, RESS

November 8, 2019

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

Dear Ms. Long,

EB-2019-0266 – Hydro One Sault Ste. Marie Limited Partnership's 2020 Transmission Revenue Cap IR Application and Evidence Filing

Hydro One Networks Inc. on behalf of Hydro One Sault Ste. Marie Limited Partnership ("HOSSM"), is submitting HOSSM's annual Transmission Revenue Cap IR Application for 2020 and prefiled evidence in support of the Application, using the Ontario Energy Board's ("OEB") Regulatory Electronic Submission System.

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

Sincerely,

ORIGINAL SIGNED BY FRANK D'ANDREA

Frank D'Andrea

EXHIBIT LIST

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APPLICATION

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

AND IN THE MATTER OF an application by Hydro One Sault Ste. Marie Inc. on behalf of Hydro One Sault Ste. Marie Limited Partnership for an Order or Orders pursuant to section 78 of the *Ontario Energy Board Act, 1998* for 2020 transmission rates and related matters.

EB-2019-0266

1. The applicant, Hydro One Sault Ste. Marie LP ("HOSSM"), carries on the business of owning and operating electricity transmission facilities in the vicinity of Sault Ste. Marie, Ontario.

2. HOSSM's core business is the operation of a regulated transmission utility in Ontario. However, from time to time HOSSM may encounter matters that may be considered to be non-utility business. To the extent these matters arise, any resultant impacts will be segregated from HOSSM's rate-regulated activities.

3. HOSSM hereby applies to the Ontario Energy Board (the "Board" or the "OEB") for an Order or Orders made pursuant to Section 78 of the *Ontario Energy Board Act, 1998,* as amended (the "OEB Act"), approving HOSSM's proposed revenue requirement to be reflected in Ontario's 2020 transmission electricity rates.

4. The Applicant has followed the filing requirements applicable to a revenue cap index proposal, as set out in the OEB's *Filing Requirements for Electricity Transmitters* and discussed in Exhibit A, Tab 3, Schedule 1.

5. In the OEB's Decision and Order for Hydro One Inc.'s Mergers, Acquisitions, Amalgamations and Divestitures ("MAAD"s) application, EB-2016-0050, the OEB approved a ten-year deferral period for rebasing of the revenue requirement of Great Lakes Power Transmission Inc. ("GLPT"). (On January 16, 2017, GLPT's name was changed to Hydro One Sault Ste. Marie LP.) In the same Decision and Order, the OEB determined that HOSSM would continue with its 2016 revenue requirement and bring forward a separate rate application, proposing a revenue cap index for the deferral period.

6. In the OEB's Decision and Order for the HOSSM 2019 revenue cap Incentive Rate-setting ("IR") mechanism application (EB-2018-0218), the OEB approved the proposed revenue cap index ("RCI") framework methodology and determined that this framework would be used to determine HOSSM's base transmission revenue requirement for the years 2019 to 2026 inclusive.

7. HOSSM is seeking OEB approval for its 2020 base revenue requirement of $40,818,914. This is calculated using HOSSM's 2019 OEB-approved revenue requirement as the base revenue and then applying an annual adjustment factor, per the revenue cap index framework. Please refer to Exhibit A, Tab 4, Schedule 1 for more information. HOSSM's resultant revenue requirement will then be included in the Board's determination of the 2020 Uniform Transmission Rates for Ontario.

8. HOSSM requests that the proposed revenue requirement be reflected in rates effective January 1, 2020. However, if implementation occurs after January 1, 2020, HOSSM requests that the existing transmission rates be made interim to permit the implementation of the proposed revenue requirement effective as of January 1, 2020.

9. In the event that a final OEB decision for HOSSM's 2020 revenue requirement is not received prior to January 1, 2020, HOSSM requests either:
    a. approval to track any forgone revenue variance in a regulatory account for disposition in a future HOSSM rates application; or,
    b. OEB direction to calculate the difference in rates between the effective date and the implementation date and include that amount in the final 2020 OEB-approved UTR's consistent with the treatment and direction given in the OEB's Order and Decision in HOSSM's 2019 Application[1].

10. HOSSM is not requesting approval to disburse any additional deferral and variance account balances beyond those amounts approved by the OEB in the EB-2018-0218 application, as no new audited year-end balances are available. Please refer to Exhibit B, Tab 1, Schedule 1 of the prefiled evidence for further information.

11. Based upon the Board's Decision in EB-2018-0218, HOSSM will continue to maintain, in the test period, sub-accounts for Infrastructure Investment, Green Energy Initiatives and Preliminary Planning Costs, within account 1508; and based upon the Accounting Procedures Handbook, HOSSM will continue to

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[1] EB-2018-0218 – Decision and Order June 20, 2019, p. 32

maintain, in the test period, account 1592 for tax variances and account 1595 related to previously approved regulatory asset collections.

12. The total bill impact for a typical medium density residential (Hydro One R1) customer consuming 750 kWh monthly is an increase of 0.02% or $0.02 per month. A typical General Service Energy less than 50 kW (Hydro One GSe < 50 kW) customer consuming 2,000 kWh monthly will result in a total bill increase of 0.01% or $0.04 per month. For more information regarding the calculation of 2020 UTRs, total monthly bill impacts and transmission rate schedules, refer to the schedules in Exhibit C – *Cost Allocation and Rate Design*.

13. This Application is supported by written evidence. The written evidence will be prefiled and may be amended from time to time, prior to the Board's final decision on this Application.

14. The Applicant requests that, pursuant to Section 34.01 of the Board's *Rules of Practice and Procedure*, this proceeding be conducted by way of written hearing.

15. HOSSM's internet address is https://www.hydroone.com/hydro-one-sault-ste-marie. More specifically, this application and related documentation can be found in the Regulatory section of the HOSSM website at: https://www.hydroone.com/about/regulatory/hydro-one-sault-ste-marie

16. All persons in Ontario are affected by this Application as this application impacts Ontario's Uniform Transmission Rates. It is therefore impractical to set out their names and addresses because they are too numerous.

17. The Applicant requests that a copy of all documents filed with the Board in this proceeding be served on the Applicant and the Applicant's counsel, as follows:

The Applicant:

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

Mailing Address: 7th Floor, South Tower
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The Applicant's Counsel:

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8th Floor, South Tower
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Toronto, Ontario M5G 2P5

Telephone: (416) 345-6305
Fax: (416) 345-6972
Email: mengelberg@HydroOne.com

DATED at Toronto, Ontario, this 8th day of November, 2019.

By its counsel,

ORIGINAL SIGNED BY MICHAEL ENGELBERG

____

Michael Engelberg

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 Sault St. Marie Limited Partnership's 2020 transmission application (EB-2019-0266) is accurate, consistent and complete to the best of my knowledge.

DATED this 8th day of November, 2019.

ORIGINAL SIGNED BY FRANK D' ANDREA

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FRANK D'ANDREA

COMPLIANCE WITH APPLICABLE FILING REQUIREMENTS

1. INTRODUCTION

HOSSM is seeking revenue requirement approval for 2020 in this Application via a Revenue Cap IR adjustment mechanism.

In preparing this Application, HOSSM has followed the filing requirements applicable to a Revenue Cap IR proposal, and has done so in accordance with the direction and guidance provided by the OEB via;

- Chapter 2 of the Board's Filing Requirements for Electricity Transmission Applications, Chapter 2: Revenue Requirement Applications dated February 11, 2016;
- Chapter 5 of the Board's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5: Consolidated Distribution System Plan Filing Requirements dated March 28, 2013;
- The Board's Handbook to Electricity Distributor and Transmitter Consolidations dated January 19, 2016 ("the Handbook");
- The Board's direction as set out in the Decision and Order in proceeding EB-2016-0050: Application for the acquisition of Great Lakes Power Transmission Inc. by Hydro One dated October 13, 2016; and
- The Board's direction as set out in the Decision and Order in proceeding EB-2018-0218: HOSSM application for electricity transmission revenue requirement effective January 1, 2019 dated June 20, 2019. For further discussion, refer to Exhibit A, Tab 3, Schedule 2.

SUMMARY OF OEB DIRECTIVES AND COMPLIANCE WITH PAST OEB DECISIONS

In addition to preparing this Application consistent with the Transmission Filing Requirements and other OEB pronouncements and guidance, HOSSM has prepared this Application in alignment with the OEB's prior decisions and guidance regarding prior relevant HOSSM applications.

The following recent relevant OEB-decisions have been incorporated into HOSSM's 2020 revenue cap IR Application:

1. PREVIOUS RATE CASES

1.1 EB-2016-0050

On October 13, 2016, the OEB approved an application by Hydro One Inc. to purchase all of the issued and outstanding voting securities of GLPT's general partner, Great Lakes Power Transmission Inc. ("the MAADs decision").

The OEB accepted Hydro One's proposal to defer the rebasing of rates for GLPT for a 10 year period as well as the implementation of the proposed earning sharing mechanism for years six to ten of the rebasing of the rates deferral period. The OEB did not accept GLPT'S proposal to reset its rates at the beginning of the ten-year period and determined that GLPT was to continue with its existing 2016 revenue requirement. The OEB directed GLPT to file a new rate application, proposing a revenue cap index framework for the deferral period that also includes the components set out in the updated Chapter 2 Filing Requirements for Electricity Transmission Applications (Transmission Filing Requirements).

1.2 EB-2018-0218

HOSSM filed an application to the OEB for approval of changes to its base transmission revenue requirement for 2019. The proposal was to increase its current 2016 base transmission revenue requirement through an incentive rate-setting framework which takes the form of a revenue cap index mechanism.

In its Decision and Order, the OEB approved the incentive rate-setting framework for determining HOSSM's rates in 2019 and indicated that it expects HOSSM to continue to use this Board-approved framework throughout the OEB-approved rebasing deferral period (i.e. up until 2026) by filing annual revenue cap IR adjustment applications.

In HOSSM's EB-2018-0218 application, the OEB approved the following items.

1.2.1 REVENUE CAP FRAMEWORK

In its Decision and Order for HOSSM's 2019 revenue requirement, the OEB approved the following revenue cap index calculation formula;

$$\mathrm{RR}t = \mathrm{RR}_{t-1} * (1+ (I_t - X))$$

Where:

$\mathrm{RR}t$ is the revenue (requirement for year t)

I_t is the inflation index for year t

X is the X-factor, composed of the base productivity factor and a stretch factor

HOSSM proposes to continue using the OEB-approved revenue cap framework and approved revenue cap formula.

1.2.2 INFLATION FACTOR CALCULATION

In its Decision and Order for HOSSM's 2019 revenue requirement the OEB approved the appropriate weights to be used for the inflation factor calculation. These are a 2-factor Input Price Index (IPI) measure 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 was derived from the analysis conducted by Power Systems Engineering Inc. ("PSE") in its study found in HOSSM's OEB-approved 2019 Revenue Cap IR application.

The updated annual percentage for both the GDP-IPI and the Average Weekly Earnings for Workers in Ontario was released by the OEB on October 31, 2019, for use in revenue requirement applications effective in 2020. Those OEB-released rates are included in this Application.

1.2.3 X-FACTOR ADJUSTMENT - PRODUCTIVITY AND STRETCH FACTORS

In HOSSM's 2019 revenue cap IR application proceeding EB-2018-0218, the OEB approved a productivity factor of 0.0%, stating that this was, "a factor indicative of the change in the productivity expected for the transmission sector as a whole."[1] For the Stretch Factor, the OEB approved a factor of 0.3% stating the reason to do so as, "to provide an incentive to Hydro One SSM beyond the rate of inflation and balance the

[1] EB-2018-0218 - Decision and Order, June 20, 2019 p. 19

needs of its customers and shareholders"[2]. The OEB approved this stretch factor for the duration of HOSSM's OEB-approved revenue cap framework i.e. until 2026.

2. DEFERRAL AND VARIANCE ACCOUNTS

In EB-2018-0218, HOSSM executed the disposition of certain account balances taken from its the most up-to-date annual Continuity Schedules based on audited results for its deferral and variance accounts. As of the time of filing this 2020 revenue requirement application, no further audited year-end financial period results are available for HOSSM deferral and variance accounts.

HOSSM is not requesting approval to disburse any account balances beyond those approved by the OEB in the 2019 revenue cap IR application.

3. EARNINGS SHARING MECHANISM AND OTHER REGULATORY FEATURES

In HOSSM's 2019 OEB-approved rate application, the OEB confirmed an ESM would not be applicable until the beginning of 2022[3].

Also in the 2019 revenue requirement application approval, the OEB confirmed that both a Z-Factor[4] and Incremental Capital Module[5] were available if required. HOSSM is not seeking recovery of any amounts based on these regulatory features in this application.

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[2] EB-2018-0218 - Decision and Order, June 20, 2019 p. 20
[3] EB-2018-0218 - Decision and Order, June 20, 2019 p. 21
[4] EB-2018-0218 - Decision and Order, June 20, 2019 p. 23
[5] EB-2018-0218 - Decision and Order, June 20, 2019 p. 22

REVENUE CAP APPLICATION SUMMARY

1. INTRODUCTION

The revenue requirement for each transmitter is approved by the OEB and is used to set uniform transmission rates that apply throughout Ontario. This HOSSM Application is requesting the OEB approve an adjustment to its base revenue requirement based on HOSSM's OEB-approved Revenue Cap IR approach. As detailed in Chapter 2 of the *Filing Requirements for Electricity Transmitter Applications*, a transmitter can propose an incentive mechanism for adjusting the revenue requirement on an annual basis. The methodology utilized is a Revenue Cap IR in which the revenue requirement for the Test year t+1 is equal to the revenue requirement in the Test year t, inflated by the Revenue Cap Index ("RCI") set out below. The formula ensures that a utility's rates will increase at a rate that is less than inflation.

An RCI is an incentive-based approach that includes expectations for the development of an incentive mechanism, as well as productivity and stretch commitments. Transmitters are to propose and substantiate the appropriate method and commitments for these elements. The Transmission Filing Requirements dated February 11, 2016[1], describe the purpose of productivity and stretch factors as the "sharing of benefits" for a revenue cap index. The sharing of benefits is accomplished by subtracting the productivity and stretch factors from the inflation factor in the revenue cap index formula. The intent is to ensure that customers will share in the benefits derived from transmitters' performance incentives. This is also consistent with the OEB's Renewed Regulatory Framework for Electricity ("RRFE") as most recently set out in the Handbook for Utility Rate Applications (the "Handbook"), released by the OEB in October 2016.

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[1] Filing Requirements For Electricity Transmission Applications, Chapter 2, Revenue Requirement Applications, dated February 11, 2016, page 5

This Revenue Cap IR Application is the second such application filed with the OEB for a rate adjustment to HOSSM's revenue requirement using the OEB-approved revenue cap IR framework. In HOSSM's first Revenue Cap IR application, the OEB accepted HOSSM's proposed revenue cap IR framework methodology[2] (an annual revenue cap index adjustment application for setting its 2019 revenue requirement) for determining rates in the years 2019 to 2026 inclusive. Per the OEB's decision[3], HOSSM is expected to continue to use this OEB-approved revenue cap IR framework throughout the OEB-approved HOSSM rate rebasing deferral period by filing annual revenue cap adjustment applications.

The RCI approved by the OEB for calculating HOSSM's 2020 revenue requirement includes an industry-specific inflation factor and a productivity factor. Consistent with the RRFE, the productivity factor is explicitly included in the rate adjustment mechanism and provides an incentive to achieve capital and OM&A productivity improvements.

The RCI is expressed as:

$$RCI = I - X$$

Where:

"I" is the Inflation Factor, based on Hydro One Networks Inc.'s custom weighted two-factor input price index; and

"X" is the Productivity Factor, which includes a Stretch Factor.

1.1 INFLATION FACTOR

HOSSM proposes to use the RCI Inflation Factor ("I") calculation approved by the OEB in its prior 2019 transmission rate proceeding (EB-2018-0218). The Inflation Factor is

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[2] EB-2018-0218 - Decision and Order, June 20, 2019
[3] EB-2018-0218 - Decision and Order, June 20, 2019 p. 20

designed to be an external measurement of the broader transmission industry labour/non-labour weights and would be the same regardless of the transmission company filing it.[4]

In the Decision and Order for HOSSM's 2019 revenue requirement[5] the OEB approved the appropriate weights to be used for the inflation factor calculation.

The proposed Inflation Factor ("I") is 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 weighting of 14% labour and 86% non-labour is derived from the OEB-approved study conducted by Power Systems Engineering Inc. ("PSE") in HOSSM's OEB-approved 2019 Revenue Cap IR application (EB-2018-0218).

The latest annual percent change for the GDP-IPI and the Average Weekly Earnings for Workers in Ontario was released by the OEB on October 31, 2019, for use in applications for rates effective in 2020. The derivation of HOSSM's 2020 proposed Inflation Factor is shown in Table 1 below.

[4] EB-2018-0218 Hydro One Sault Ste. Marie, Interrogatory I-1-58
[5] EB-2018-0218 - Decision and Order, June 20, 2019

Table 1 - Derivation of Inflation Factor

	Non-Labour GDP-IPI (FDD) - National							Labour AWE - All Employees - Ontario			Annual Growth for the 2-factor IPI
Year	Q1	Q2	Q3	Q4	Annual	Annual % Change (A)	Weight (B)	Annual	Annual % Change (C)	Weight (D)	Annual % Change ([A*B] + [C*D])
2017	108.00	108.50	108.30	109.00	108.45			992.42			
2018	109.40	109.80	110.50	111.10	110.20	1.6%	86%	1021.40	2.9%	14%	1.8%

HOSSM has used the Inflation Factor of 1.8% derived above, in its RCI calculation for the purpose of this Application. The inflation factor calculation is expressed as:

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

Using the OEB-approved methodology and weightings an Inflation Factor of 1.8% was derived.

1.2 PRODUCTIVITY AND STRETCH FACTORS

1.2.1 PRODUCTIVITY FACTOR

In HOSSM's 2019 Revenue Cap IR application proceeding EB-2018-00218, the OEB approved a productivity factor of 0.0%, stating that this was, "a factor indicative of the change in the productivity expected for the transmission sector as a whole."[6] HOSSM's management and work programs are provided by a service level agreement, resulting in access to qualified and flexible resources when needed, allowing HOSSM to remain cost-efficient. HOSSM's service level agreement integrates Hydro One Networks Inc.'s productivity improvements into HOSSM maintenance and operations programmes.

[6] EB-2018-0218 - Decision and Order, June 20, 2019 p. 19

1.2.2 STRETCH FACTOR

The OEB approved a factor of 0.3% in HOSSM's prior 2019 Revenue Cap IR application, "to provide an incentive to Hydro One SSM beyond the rate of inflation and balance the needs of its customers and shareholders"[7]. This stretch factor was approved for the duration of HOSSM's OEB-approved revenue cap framework until 2026. The stretch factor component of the X-factor is intended to reflect the incremental productivity gains that transmitters are expected to achieve under Incentive Rate-setting.

1.3 REVENUE CAP INDEX FRAMEWORK

HOSSM's OEB-approved revenue cap index framework provides an allowed rate of change in the price of regulated services to be adjusted by the growth in an inflation factor minus an X-factor. The X-factor is comprised of a productivity component and a stretch factor. The productivity factor is intended to be the external benchmark that all distributors are expected to achieve, using estimates of the long-run trend in TFP growth for the regulated industry. In HOSSM's 2019 OEB-approved revenue requirement application the productivity and stretch factors were determined to have been 0.0% and 0.3% respectively (refer to Exhibit A, Tab 3, Schedule 2).

HOSSM proposes to continue with the RCI expressed as:

$$Revenue\ Adjustment = i - X$$

Where;

(i) Inflation Factor = 1.8% (as calculated for 2020)

(x) Productivity Factor + Stretch Factor = 0.0% + 0.3% = 0.3%

Therefore, as shown below, the proposed revenue requirement for 2020 using current parameters would be 1.5%.

[7] EB-2018-0218 - Decision and Order, June 20, 2019 p. 20

1.4 REVENUE CAP INDEX SUMMARY

Table 2 below summarizes the RCI, by component that HOSSM is proposing to use to determine the total revenue requirement for ratemaking purposes for 2020.

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

Revenue Cap Index by Component	2020
Inflation Factor (I)	1.8%
Less:	
Productivity Factor (X)	(0.3%)
Total Revenue Cap Index (RCI)	1.5%

The Inflation Factor in Table 2 will be updated annually. However, as described above and as outlined in HOSSM's 2019 Revenue Cap application approval[8], the OEB has determined HOSSM's Productivity Factor (X) will remain unchanged throughout the RCI term. Table 3 below summarizes the Total Revenue Requirement that would result in 2020.

Table 3 - Revenue Requirement by Year

Year	Formula	Revenue Requirement
2019	Approved Revenue Requirement	$40,215,679
2020	2019 Base Revenue Requirement x 1.015*	$40,818,914

** Calculations assume the RCI in Table 2.*

1.5 ADDITIONAL REVENUE CAP IR FEATURES

HOSSM is proposing to continue with the following OEB-approved additional features in this Application.

[8] EB-2018-0218 - Decision and Order, June 20, 2019 p. 20

1.5.1 Z-FACTOR

HOSSM confirms, consistent with the Handbook and the OEB's recent decision on HOSSM's 2019 revenue cap application, that the OEB's Z-factor mechanism is available to it over the term of the revenue cap IR framework period. HOSSM has not identified to-date any specific events or circumstances that meet the Z-factor criteria for 2020.

1.5.2 INCREMENTAL CAPITAL MODULE

HOSSM confirms, consistent with the Handbook and the OEB's recent decision on HOSSM's 2019 revenue cap application[9], that the incremental capital module ("ICM") is available to it over the term of the revenue cap IR framework period. HOSSM has not identified any specific capital projects that would qualify for ICM treatment for 2020.

[9] EB-2018-0218 – Decision and Order p.22

REGULATORY ACCOUNTS OVERVIEW

1. DEFERRAL AND VARIANCE ACCOUNTS OVERVIEW

Consistent with the OEB-approved 2019 revenue cap IR application HOSSM is requesting approval for continuance of the following deferral/variance accounts:

- Other Regulatory Asset Account 1508;
  - Sub-Accounts:
    - Infrastructure Investment;
    - Green Energy Initiatives and Preliminary Planning Costs;
    - Property Tax and Use and Occupation Permit Fee Variance;
    - International Financial Reporting Standards ("IFRS") Gains and Losses; and
    - Ontario Energy Board ("OEB") Cost Assessments;
- Based upon the Accounting Procedures Handbook, HOSSM will continue to maintain account 1595 related to previously approved regulatory asset recovery; and
- Described in the OEB's 2008 report entitled *Supplemental Report of the Board on 3rd Generation Incentive Regulation for Ontario's Electricity Distributors*, a 50/50 sharing of impacts of legislated tax changes from a utility's tax rates embedded in its OEB approved base rate known at the time of application. HOSSM is proposing to maintain in the rebasing deferral period a sub-account within account 1592 to capture these impacts.

As described in EB-2018-0218 of Exhibit A, Tab 2, Schedule 1, in the event HOSSM encounters unforeseen events which meet the three defined eligibility criteria of Causation, Materiality and Prudence, Hydro One will record the amounts in a Z-factor deferral account (Account 1572) for future prudency review and disposition approval by the OEB in a future rate filing. In its Decision and Order of that application the OEB found the Z-factor treatment proposal to be consistent with OEB policy and is reasonable[1].

2. DISBURSAL OF DEFERRAL ACCOUNTS

HOSSM is not requesting approval to disburse any account balances beyond those approved by the OEB in the 2019 Price Cap IR application.

In its 2019 revenue cap IR application, HOSSM provided the most up-to-date annual Continuity Schedules based on audited results for its deferral and variance accounts in EB-2018-0218 at Exhibit E, Tab 1, Schedule 4, for the years 2014 to 2018. HOSSM confirms no further year-end periods have elapsed since that time. HOSSM's 2019 deferral and variance account balances will be available post the 2019 year-end, subsequent to audit and those results will be incorporated, as appropriate, in a future HOSSM revenue cap IR application.

3. OTHER MATTERS

In the event that a final OEB decision for HOSSM's 2020 revenue requirement is not received prior to January 1, 2020, HOSSM requests either:

a. approval to track any foregone revenue variance in a regulatory account for disposition in a future HOSSM rates application, or,
b. OEB direction to calculate the difference in rates between the effective date and the implementation date and include that amount in the final 2020 OEB-approved UTR's consistent with the treatment and direction given in the OEB's Order and Decision in HOSSM's 2019 Application.

[1] EB-2018-0218 - Decision and Order, June 20, 2019 p. 23

PROPOSED 2020 RATES REVENUE REQUIREMENT AND BILL IMPACTS

1.0 OVERVIEW OF UNIFORM TRANSMISSION RATES

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002, as per the OEB's Decision in RP-2001-0034/ RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Uniform Transmission Rates ("UTR") Schedules, which were effective on July 1, 2019, as part of the OEB's Decision and Rate Order in EB-2019-0164 issued on July 25, 2019, are filed as Exhibit C, Tab 2, Schedule 1, Attachment 1. Exhibit C, Tab 2, Schedule 1, Attachment 2 shows the revenue requirement and charge determinant details used to derive the currently approved 2019 UTRs.

Since rates are established on a uniform basis, HOSSM's requested revenue requirement is a contributor to the total revenue requirement to be collected from the provincial UTR. The revenue requirement for all the other transmitters in the province approved to participate in the UTRs is added to that of HOSSM in order to calculate the total transmission revenue requirement to be collected via the UTR.[1] The total revenue requirement from all transmitters is then allocated to the Network, Line Connection and Transformation Connection rate pools in order to establish uniform rates by pool. The revenue requirement for the other transmitters (except B2M LP, where the entire revenue requirement is allocated to the Network pool) are allocated to the three rate pools based on the proportions established by Hydro One Networks Transmission's Cost Allocation process.

[1] The other four transmitters currently included in the UTRs are Hydro One Networks Transmission, B2M LP, Canadian Niagara Power Inc., and Five Nations Energy Inc. Niagara Reinforcement LP has applied to be included in the UTRs for 2020.

Once the revenue requirement by rate pool is established, rates are determined by applying the Provincial charge determinants for each pool to the total revenue 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.

2.0 HOSSM 2020 REVENUE REQUIREMENT

The proposed 2020 base revenue requirement for HOSSM is $40,818,914 (refer to Exhibit A, Tab 4, Schedule 1).

As discussed in Exhibit B, Tab 1, Schedule 1, HOSSM is not requesting approval to clear any regulatory account balances in this application. As such, the 2020 rates revenue requirement for HOSSM used to calculate the UTRs is the same as the total revenue requirement. As mentioned in Section 1 above, the rates revenue requirement for HOSSM gets allocated among the three rate pools (Network, Line Connection and Transformation Connection) using percentage allocation for Hydro One Networks Transmission. The resulting pool allocation of HOSSM's rates revenue requirement is shown in Table 1.

Table 1: HOSSM's 2020 Rates Revenue Requirement by Rate Pool

Transmitter	Network	Line Connection	Transformation Connection	Total
HOSSM	$23,205,504	$5,798,734	$11,814,676	$40,818,914

3.0 HOSSM 2020 CHARGE DETERMINANTS

As per the OEB Decision in HOSSM's 2019 revenue requirement application (EB-2018-0218), the charge determinants shown in Table 2 below are to remain in place for the deferred rebasing period (i.e. until 2026).

Table 2: Charge Determinants (in MWs)

Transmitter	Network	Line Connection	Transformation Connection
HOSSM	3,498.236	2,734.624	635.252

The proposed 2020 UTR schedules are provided in Exhibit C, Tab 3, Schedule 1, Attachment 1, and the revenue requirement and charge determinants details used to calculate the proposed 2020 UTRs are provided in Exhibit C, Tab 3, Schedule 1, Attachment 2.

In its 2020-2022 Transmission Custom IR Application (EB-2019-0082), Hydro One is proposing to update the definition of billing demand for the Line and Transformation Connection services to reflect the changes in the embedded generation market over the years, such as the inclusion of energy storage facilities. The "Embedded Generation" section (page 3) and Note 3 (page 5) in Exhibit C, Tab 3, Schedule 1, Attachment 1 in this application align with Hydro One's proposed changes in EB-2019-0082[2]. The proposed 2020 UTR calculation includes the proposed 2020 HOSSM rates revenue requirement and the currently approved (2019) values for HONI Transmission, B2M LP, Canadian Niagara Power Inc., and Five Nations Energy Inc.

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[2] See EB-2019-0082 Exhibit JT 2.34-Q18 for more information.

4.0 BILL IMPACTS

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. The approach used in HONI's Transmission Rate Application (EB-2019-0082) has been adopted to determine the impact of proposed changes to transmission rates on an average customer's bill. Table 3 below shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

Table 3: Estimated Transmission Cost as a Percentage of Total Electricity Market Costs

Bill Component	¢/kWh	Source
Commodity	11.49	IESO Monthly Market Report December 2018
Wholesale Market Service Charges	0.39	IESO Monthly Market Report December 2018
Wholesale Transmission Charges	1.08	IESO Monthly Market Report December 2018
Debt Retirement Charge	0.18	IESO Monthly Market Report December 2018
Distribution Service Charges	2.83	2018 Yearbook of Electricity Distributors
Total Cost	**15.97**	
Transmission as % of Total Cost for Dx-connected customers	*6.8%*	
Transmission as % of Total Cost for Tx-connected customers	*8.2%*	

The HOSSM 2019 rates revenue requirement represents about 2.3% of the total revenue requirement across all transmitters based on approved 2019 UTR calculations. This percentage has been applied to HOSSM's proposed changes in revenue requirement to calculate the net impact on average transmission rates for 2020. The figures from Table 3 above have been applied to the proposed net impact on average transmission rates to establish the average bill impact on transmission and distribution-connected customers as shown in Table 4 below.

Table 4: Average Bill Impacts on Transmission and Distribution-Connected Customers

	2019[1]	2020[2]
Rates Revenue Requirement ($Millions)	38.0	40.8
% Increase in Rates Revenue Requirement over prior year		7.4%[3]
% Impact of load forecast change		0.0%
Net Impact on Average Transmission Rates		**0.18%**
Transmission as a % of Tx-connected customer's Total Bill		8.2%
Estimated Average Transmission Customer Bill impact		**0.01%**
Transmission as a % of Dx-connected customer's Total Bill		6.8%
Estimated Average Distribution Customer Bill impact		**0.01%**

[1] 2019 Rates Revenue Requirement per Schedule A, 2019 Uniform Transmission Rates, EB-2019-0164.
[2] 2020 Rates Revenue Requirement per Exhibit A, Tab 4, Schedule 1
[3] This represents the combined impact of: 1) Revenue Cap increase of $0.6M or 1.5%; 2) Expiry of annualized deferral variance account balance of ($1.4M) being credited through 2019 UTRs (as per EB-2018-0218) and 3) Expiry of annualized foregone revenue of ($0.8M) being credited through 2019 UTRs (as per EB-2018-0218)

The total bill impact for a typical medium density residential (Hydro One R1) customer consuming 750 kWh monthly and a typical General Service Energy less than 50 kW (Hydro One GSe < 50 kW) customer consuming 2,000 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR"), as detailed in Table 5 below.

Table 5: Typical Customer Monthly Bill Impacts

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

1Total bill including HST, based on time-of-use commodity prices and distribution rates effective May 1, 2018 (implemented July 1, 2019) approved per Distribution Rate Order EB-2017-0049 (includes impacts of all applicable components of the Fair Hydro Plan).

2The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 3.

CURRENT ONTARIO TRANSMISSION RATES

The current Uniform Transmission Rate ("UTR") Schedules were approved as part of the 2019 Decision and Rate Order dated July 25, 2019 under EB-2019-0164. This approved rate schedule, and the revenue requirement and charge determinants for all transmitters used to establish the current UTRs and revenue disbursement allocators are included in the following attachments.

Attachment 1: Current (2019) Ontario Uniform Transmission Rate Schedules
Attachment 2: Current (2019) Uniform Transmission Rates and Revenue Disbursement Allocators

Filed: 2019-11-08
EB-2019-0266
Exhibit C-2-1
Attachment 1
Page 1 of 6

2019 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2019-0164

The rate schedules contained herein shall be implemented as of July 1, 2019

Issued: July 25, 2019
Ontario Energy Board

TERMS AND CONDITIONS

(A) APPLICABILITY The rate schedules contained herein pertain to the transmission service applicable to: •The provision of Provincial Transmission Service (PTS) to the Transmission Customers who are defined as the entities that withdraw electricity directly from the transmission system in the province of Ontario. •The provision of Export Transmission Service (ETS) to electricity market participants that export electricity to points outside Ontario utilizing the transmission system in the province of Ontario. The Rate Schedule ETS applies to the wholesale market participants who utilize the Export Service in accordance with the Market Rules of the Ontario Electricity Market, referred to hereafter as Market Rules. These rate schedules do not apply to the distribution services provided by any distributors in Ontario, nor to the purchase of energy, hourly uplift, ancillary services or any other charges that may be applicable in electricity markets administered by the Independent Electricity System Operator (IESO) 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]	**3.83**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand [1,3]	**0.96**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand [1,3,4]	**2.30**

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 Uniform Transmission Rates and Revenue Disbursement Allocators

(for Period July 1, 2019 to December 31, 2019)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,541,221	$1,134,788	$2,312,083	$7,988,092
CNPI	$2,641,928	$660,181	$1,345,091	$4,647,201
H1N SSM	$21,608,304	$5,399,616	$11,001,490	$38,009,410
H1N	$891,888,531	$222,870,611	$454,089,436	$1,568,848,577
B2MLP	$32,789,151	$0	$0	$32,789,151
All Transmitters	$953,469,135	$230,065,197	$468,748,100	$1,652,282,431

Transmitter	Total Annual Charge Determinants (MW)**			
	Network	Line Connection	Transformation Connection	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
HIN SSM	3,498.236	2,734.624	635.252	
H1N	244,924.157	236,948.242	202,510.123	
B2MLP	0.000	0.000	0.000	
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)	**3.83**	**0.96**	**2.30**	
FNEI Allocation Factor	**0.00476**	**0.00493**	**0.00493**	
CNPI Allocation Factor	**0.00277**	**0.00287**	**0.00287**	
H1N SSM Allocation Factor	**0.02266**	**0.02347**	**0.02347**	
H1N Allocation Factor	**0.93542**	**0.96873**	**0.96873**	
B2MLP Allocation Factor	**0.03439**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

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

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

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.

Note 3: H1N SSM 2019 Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0218 dated July 18, 2019.

Note 4: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0130 dated June 13, 2019.

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

Note 6: Calculated data in shaded cells.

PROPOSED ONTARIO TRANSMISSION RATES

The proposed Uniform Transmission Rate ("UTR") Schedule and the revenue requirement and charge determinants for all transmitters used to establish the proposed UTRs and revenue disbursement allocators are included in the following attachments.

Attachment 1: Proposed (2020) Ontario Uniform Transmission Rate Schedules
Attachment 2: Proposed (2020) Uniform Transmission Rates and Revenue Disbursement Allocators

Filed: 2019-11-08
EB-2019-0266
Exhibit C-3-1
Attachment 1
Page 1 of 6

2020 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2019-XXXX

The rate schedules contained herein shall be effective January 1, 2020

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~~ generator unit or energy storage facility are obtained after October 30, 1998; and (b) the generator unit nameplate rating is 2 MW or higher for renewable generation and 1 MW or higher for non- renewable generation or if the individual inverter unit capacity is 1 MW or higher for energy storage; and (c) the Transmission Delivery Point through which the generator or energy storage facility is connected to the transmission system attracts Line or Transformation Connection Service charges. These terms and conditions also apply to the incremental capacity associated with any refurbishments or expansions approved after October 30, 1998, to a generator or generation facility ~~unit~~ that was connected through an eligible Transmission Delivery Point on or prior to October 30, 1998 and the approved incremental generator nameplate capacity is 2 MW or higher for renewable generation and 1 MW or higher for non-renewable generation or if the individual inverter unit capacity is 1 MW or higher for expansion of energy storage facilities. 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):	**3.83**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.96**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.30**
$ Per kW of Transformation Connection Billing Demand [1,3,4]	

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

Notes:

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

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

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

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

TERMS AND CONDITIONS OF SERVICE:

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

RATE SCHEDULE: (ETS) EXPORT TRANSMISSION SERVICE

APPLICABILITY:

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

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

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

TERMS AND CONDITIONS OF SERVICE:

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

Hydro One Sault Ste. Marie LP
Projected Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period Jan 1, 2020 to December 31, 2020)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$4,541,221	$1,134,788	$2,312,083	$7,988,092
CNPI	$2,641,928	$660,181	$1,345,091	$4,647,201
HOSSM	$23,205,504	$5,798,734	$11,814,676	$40,818,914
H1N	$891,888,531	$222,870,611	$454,089,436	$1,568,848,577
B2MLP	$32,789,151	$0	$0	$32,789,151
All Transmitters	$955,066,335	$230,464,315	$469,561,286	$1,655,091,936

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	
HOSSM	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)	**3.83**	**0.96**	**2.30**	
FNEI Allocation Factor	**0.00475**	**0.00492**	**0.00492**	
CNPI Allocation Factor	**0.00277**	**0.00286**	**0.00286**	
HOSSM Allocation Factor	**0.02430**	**0.02516**	**0.02516**	
H1N Allocation Factor	**0.93385**	**0.96706**	**0.96706**	
B2MLP Allocation Factor	**0.03433**	**0.00000**	**0.00000**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

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

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

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2015-0354 dated January 14, 2016.

Note 3: HOSSM proposed 2020 Rates Revenue Requirement per Exhibit A, Tab 4, Schedule .

Note 4: HOSSM proposed 2020 Charge Determinants per OEB Decision EB-2018-0218 dated July 18, 2019

Note 5: H1N Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2018-0130 dated June 13, 2019.

Note 6: B2M LP 2019 Revenue Requirement per OEB Decision and Order EB-2018-0320 dated December 20, 2018.

Note 7: Calculated data in shaded cells.