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 Board's Decision in Proceeding RP-2001-0034/RP-2001-0035/RP-2001-0036/RP-1999-0044. The current Ontario Uniform Transmission Rates ("UTR") Schedules, which were effective on January 1, 2016 as part of the Board's Order under EB-2014-0140/EB-2015-0313, with approved 2016 UTR Order under EB-2015-0311, issued January 14, 2016, are filed as Exhibit H2, Tab 1, Schedule 1, Attachment 1.

Since rates are established on a uniform basis, Hydro One's requested transmission rates revenue requirement for the 2017 and 2018 test years contributes to the total revenue requirement to 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 the test years.[1]

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 by Hydro One Transmission's Cost Allocation process.[2] Once the revenue requirement by rate pool has been established, rates are determined by applying the provincial charge determinants for

[1] The other four transmitters currently included in the UTRs are Great Lakes Power Transmission Inc., Canadian Niagara Power Inc., Five Nations Energy Inc., and B2M Limited Partnership

[2] Except for B2M Limited Partnership, which has its full revenue requirement assigned to the Network rate pool.

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.

A forecast of the 2017 and 2018 Uniform Transmission Rates is provided at Exhibit H2, Tab 1, Schedule 2 based on the values proposed for Hydro One Transmission in this application and maintaining the currently approved values for other transmitters.

CHARGE DETERMINANTS

1. INTRODUCTION

This exhibit provides the derivation of Hydro One Transmission's charge determinants for the approved rate pools, which when combined with the charge determinants of the other transmitters for the Network, Line Connection and Transformation Connection rate pools, can be used by the Board to determine Uniform Transmission Rates ("UTRs"). The charge determinants for the 2017 and 2018 test years are based on forecast demand by customer delivery point, as described in Exhibit E1, Tab 3, Schedule 1, and are subject to the Terms and Conditions defined in the proposed Transmission Rate Schedule provided in Exhibit H2, Tab 1, Schedule 2.

2. SUMMARY OF CHARGE DETERMINANTS

The rate pool charge determinants are summarized in Table 1 for the 2017 and 2018 test years. All charge determinants have been calculated per the methodology approved in the Board's EB-2014-0140/EB-2015-0313 Decisions.

Table 1: Summary of Rate Pool Charge Determinants (MW)

Charge Determinant	Network	Line Connection	Transformation Connection
2017	244,866	236,891	202,461
2018	244,924	236,948	202,510

3. NETWORK CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Network service charge determinant is the higher of: (a) the customer's demand that is coincident with the monthly system peak; or (b) 85% of the customer's non-coincident monthly peak demand between 7 AM to 7 PM on Independent Electricity System Operator ("IESO") business days, as detailed in the proposed Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 2.

The Network service charge determinant provides time-of-use signals that encourage customers to shift their demand from coinciding with the time of the total system's monthly peak. Customers with a monthly peak demand that occurs away from the time of the total system's monthly peak will potentially benefit from a reduced Network charge. No transmission Network charges apply to customers that avoid consuming between 7 AM to 7 PM on IESO business days[1], which is the defined transmission system on-peak period.

All customers that are connected to Hydro One's transmission system incur Network service charges on a per transmission delivery point basis. The 2017 and 2018 hourly load forecast data for each customer's transmission delivery points, adjusted for losses as appropriate, are used to calculate the total charge determinants that attract Network service charges.

[1] Unless the monthly system peak demand occurs outside of the 7 AM to 7 PM period, in which case the customer's Network charge determinant will be their coincident peak demand.

4. LINE CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATIONS

The Line Connection service charge determinant is the transmission delivery point's non-coincident monthly peak demand, as detailed in the proposed Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 2.

All customers that utilize Line Connection assets owned by Hydro One Transmission incur Line Connection service charges on a per transmission delivery point basis. 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 that connect the transmission delivery point to a network station. Similarly, customers will not incur Line Connection service charges for demand at a transmission delivery point located at a network station.

The billing demand for the Line Connection service charge is the loss-adjusted demand supplied to the delivery point from the transmission system. Furthermore, the demand that is supplied by a generator unit, through a transmission delivery point that attracts Line Connection service charges, is added to the billing demand if the required government approvals for the generator unit is obtained after October 30, 1998 and if the generator unit rating is 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation. These charges also apply to the incremental capacity amount associated with any refurbishments to a generator unit approved after October 30, 1998, for which the incremental capacity is 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation of the approved refurbishment.

The 2017 and 2018 hourly load forecast data for each transmission delivery point, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Line Connection service charges.

5. TRANSFORMATION CONNECTION CHARGE DETERMINANT AND PAYMENT OBLIGATION

The Transformation Connection service charge determinant is the customer's non-coincident monthly peak demand, as detailed in the proposed Ontario Transmission Rate Schedules provided in Exhibit H2, Tab 1, Schedule 2.

All customers that utilize Transformation Connection assets owned by the Hydro One Transmission incur charges on a transmission delivery point basis. 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 billing demand for the Transformation Connection service charge is the loss-adjusted demand supplied to the delivery point from the transmission system. Furthermore, the demand that is supplied by a generator unit, through a transmission delivery point that attracts Transformation Connection service charges, is added to the billing demand if the required government approvals for the generator unit is obtained after October 30, 1998 and if the generator unit rating is 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation. These charges also apply to the incremental capacity amount associated with any refurbishments to a generator unit approved after October 30, 1998, for which the incremental capacity is 2 MW or more for renewable generation and 1 MW or higher for non-renewable generation of the approved refurbishment.

The 2017 and 2018 hourly load forecast data for each transmission delivery point, adjusted for losses as appropriate, is used to calculate the total charge determinants that attract Transformation Connection service charges.

FEES FOR WHOLESALE METER SERVICE

1. INTRODUCTION

This exhibit summarizes Hydro One's proposal for the derivation of the proposed Wholesale Meter Service ("WMS") fee that will recover the revenue requirement associated with Meter Service Provider ("MSP") services to wholesale revenue metering ("WRM") assets.

2. COSTS ASSOCIATED WITH WHOLESALE REVENUE METERING ASSETS

The WRM installations are comprised of such assets as: recorders, physical meters and related instrument transformers, wiring, and panels that require ongoing operations and maintenance expenses, including costs associated with activities to comply with the Market Rules administered by the Independent Electricity System Operator ("IESO"), and asset related charges such as depreciation and a share of the other revenue requirement costs (e.g. return on capital, taxes, etc.).

For every metering installation with respect to which a Metered Market Participant ("MMP") arranges to exit the transitional arrangement, Hydro One Transmission shall cease to be responsible for these direct or indirect costs that are required to maintain, repair, or replace any equipment necessary for wholesale revenue metering or any other purpose related to the metering installation.

Since Market Open in 2002, MMPs have been making arrangements to exit the transitional arrangement upon seal expiry of the WRM installations, as per the Market Rules, reducing Hydro One Transmission's ownership of WRMs.

Although the number of WRM installations and the associated direct and indirect costs has significantly reduced, Hydro One Transmission recognizes that there is still a cost associated with the remaining WRM assets. The costs for the wholesale revenue meter function are required to be collected from the meter service customers that are served by these WRM installations.

3. RECOVERY OF COSTS ASSOCIATED WITH WHOLESALE REVENUE METERING ASSETS

Historically, Hydro One has derived the WMS rates consistent with the approach originally approved by the Board in the Decision and Rate Order in Proceeding EB-2006-0501. This approved approach required going through an allocation process to assign costs to a Wholesale Meter rate pool using a uniform WMS rate determined on a "per meter point" basis.

However in this application, Hydro One is proposing to simplify and streamline the cost allocation process by capturing the WRM asset costs in the Transformation Connection functional category, for subsequent mapping to the Transformation Connection rate pool, as described in Exhibit G1, Tab 2, Schedule 1 and Exhibit G1, Tab 3, Schedule 1 respectively.

As a result of expanding the Transformation Connection functional category to now include the small number of remaining WRM assets, a separate Wholesale Meter functional category no longer exists. The associated costs are bundled with the assets in the Transformation Connection functional category, and subsequently recovered through the Transformation Connection service rate.

In order to ensure the costs attributable to WRMs continue to be recovered from the MMPs who are served by these WRM installations, Hydro One Transmission is proposing to establish an annual fee approach. Hydro One Transmission proposes to set an annual fee of $7,900 per meter point for MSP services provided to MMPs that remain under the transitional arrangement. This annual fee is consistent with the approved WMS rate currently in effect[1]; and aligns with the WMS rate that has been consistently calculated since 2012 under the previous methodology. It is proposed that this annual fee approach would remain in place until all the remaining meter points exit the transitional arrangement.

The amount collected from the proposed WMS fee will be directly assigned to the Transformation Connection rate pool to offset the wholesale meter costs that are now included as part of that rate pool.

The WMS fee is in addition to the existing Exit Meter fee, and will not be applied to MMPs that exit the transitional arrangement in accordance with Hydro One Transmission's wholesale meter exit policy.

It is proposed that the Exit Fee for meter installations, which is based on the average Net Book Value of stranded wholesale revenue metering assets, remain at $5,200 per meter point as approved by the Board in Proceeding EB-2012-0031.

4. FORECAST REVENUE FOR WMS AND EXIT FEE

Table 1 below provides data for 2017 and 2018 on the forecast number of meter points and the revenue to be recovered through the proposed WMS fee.

---

[1] Approved by the Board in its Decision and Rate Order in Proceeding EB-2014-0140

Table 1: Forecast WMS Revenue

Year	Forecast Number of Meter Points (Mid-Year)	WMS Fee ($/year)	Forecast Revenue Collected for MSP Service ($/year)
2017	42	$7,900	$331,800
2018	35	$7,900	$276,500

The proposed fee schedule for the WMS and Exit Fee are provided in Exhibit H2, Tab 2, Schedule 2. The WMS fee will be administered by Hydro One Transmission.

RATES FOR EXPORT TRANSMISSION SERVICE

1. INTRODUCTION

The Independent Electricity System Operator ("IESO") collects Export Transmission Service ("ETS") revenues and remits them on a monthly basis to Hydro One, whose transmission system is used to facilitate export transactions at the point of interconnection with the neighbouring markets.

2. EXPORT TRANSMISSION SERVICE TARIFF DESIGN

Since the initial setting of the ETS rate, there have been many competing arguments advanced by stakeholders with respect to the basis of the tariff design and appropriateness of the charge level. As a result, over the years, the ETS has been determined through a combination of stakeholder agreements and Board interim Decisions, based on Board-directed studies performed by both the IESO, and most recently, by Hydro One Transmission involving stakeholder input.

In its Decision in Hydro One's 2013/2014 Transmission Rate Application (EB-2012-0031), the Board indicated that, in the absence of an analysis of cost causality (through a cost allocation study), there was not an adequate basis for the Board to approve a change to the ETS rate of $2.00/MWh, then in effect.

As a part of Hydro One's 2015/2016 Transmission Rate Application (EB-2014-0140), Hydro One Transmission engaged Elenchus Research Associates ("Elenchus") to perform a cost allocation study of network assets utilized by export transmission customers to determine the ETS rate based on cost causality principles. The criteria for Elenchus' recommended methodology to allocate costs are defined below:

- Utilize the prior year actual hourly data for domestic and export customers (as forecast domestic and export hourly data is not available from either Hydro One or IESO);
- Utilize the 12 CP as the allocator in apportioning assets between domestic and export customers in order to develop composite allocators to allocate shared expenses;
- Allocate only dedicated assets used to serve export customers and related expenses to the export customer class. No asset related costs associated with shared assets should be allocated to export customers;
- Allocate expenses related to the use of shared assets to export customers using composite assets as allocator;
- Exclude external revenues from the allocation to the export customer class; and
- Calculate the ETS rate based on Hydro One Transmission's proposed Network revenue requirement, adjusted to include other transmitters' approved revenue requirement reflected in the UTRs.

The cost allocation study completed by Elenchus recommended an ETS rate of $1.70/MWh for 2015 and 2016 as being reflective of the cost of providing export service.

For the purpose of reaching a settlement, all parties agreed to an ETS rate of $1.85/MWh for 2015 and 2016. While the parties to the settlement noted that the agreement was not to be interpreted as acceptance of Elenchus' cost allocation study and recommendations, the ETS rate was informed by the study's analysis on cost causality for export service. In its EB-2014-0140 Decision, the Board approved the ETS rate change from $2.00/MWh to $1.85/MWh, effective January 1, 2015 for two years.

Hydro One Transmission proposes to maintain the currently settled value of $1.85/MWh for ETS through the 2017 and 2018 period.

3. EXPORT TRANSMISSION SERVICE REVENUE

Hydro One's ETS revenues, used for establishing the rates revenue requirement proposed in this application, are determined based on the currently approved tariff of $1.85/MWh and the three year historical average volume of electricity exported from, or wheeled-through, Ontario over its transmission system.

For 2017 and 2018, the ETS revenue will continue to be disbursed through a decrease to the revenue requirement for the Network rate pool, as per the cost allocation process approved by the Board. The forecast for ETS revenue is $39.2 million and $40.1 million per year for 2017 and 2018, respectively.

Hydro One proposes to revise its rates revenue requirement to reflect the Board's Decision and Order with respect to the ETS tariff as part of the Draft Rate Order to be submitted in connection with finalizing the 2017 Uniform Transmission Rates to be approved.

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 determining the impact of proposed changes to transmission rates on an average customer's bill the same approach used in the EB-2014-0140, EB-2012-0031 and EB-2010-0002 transmission rate applications has been adopted.

Table 1 below shows the estimated average transmission cost as a percentage of the total bill for a transmission and a distribution-connected customer.

Table 1: Transmission Cost as a Percentage of Total Bill

Bill Component	**¢/kWh**	**Source**
Commodity	10.14	IESO Monthly Market Report December 2015
Wholesale Market Service Charges	0.39	IESO Monthly Market Report December 2015
Wholesale Transmission Charges	1.02	IESO Monthly Market Report December 2015
Debt Retirement Charge	0.70	IESO Monthly Market Report December 2015
Distribution Service Charges	2.85	2014 Yearbook of Electricity Distributors
Total Cost	**15.10**	
Transmission as Percentage of Total Cost for Dx-connected customers		***6.8%***
Transmission as Percentage of Total Cost for Tx-connected customers		***8.3%***

The figures from Table 1 have been applied to the proposed increase in transmission revenue requirement in 2017 and 2018 to establish average bill impacts as shown in Table 2.

Table 2: Average Bill Impacts on Transmission and Distribution-connected Customers

	2016	2017	2018
Rates Revenue Requirement ($ millions) [1]	**1,480.5**	**1,504.7**	**1,585.3**
% Increase in Rates RR over prior year		1.6%	5.4%
% Impact of load forecast change		2.1%	0.0%
Net Impact on Average Transmission Rates		**3.7%**	**5.4%**
Transmission as a % of Tx-connected customer's Total Bill		8.3%	8.3%
Estimated Average Bill impact		***0.3%***	***0.4%***
Transmission as a % of Dx -connected customer's Total Bill		6.8%	6.8%
Estimated Average Bill Impact		***0.3%***	***0.4%***

[1] This amount is net of the $0.3million in WMS revenue which accounts for the difference when comparing to the total rates revenue requirement shown in Exhibit E1, Tab 1, Schedule 1.

The total bill impact for a typical Hydro One medium density residential (R1) customer consuming 350 kWh, 750 kWh and 1800 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 3.

Table 3: Typical Medium Density (R1) Residential Customer Bill Impacts

	Typical R1 Residential Customer		
	350 kWh	**750 kWh**	**1800 kWh**
Total Bill as of Jan 1, 2016[1]	$ 102.95	$ 179.37	$ 379.98
RTSR included in 2016 R1 Customer's Bill	$ 4.37	$ 9.36	$ 22.47
Estimated 2017 Monthly RTSR[2]	$ 4.52	$ 9.69	$ 23.26
2017 increase in Monthly Bill	**$ 0.15**	**$ 0.33**	**$ 0.79**
2017 increase as a % of total bill	*0.1%*	*0.2%*	*0.2%*
Estimated 2018 Monthly RTSR[2]	$ 4.75	$ 10.18	$ 24.44
2018 increase in Monthly Bill	**$ 0.23**	**$ 0.49**	**$ 1.18**
2018 increase as a % of total bill	*0.2%*	*0.3%*	*0.3%*

[1] Total bill including HST, based on time-of-use RPP commodity pricing and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079.
[2] The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs per EB-2015-0311.

The total bill impact for a typical Hydro One General Service Energy less than 50 kW ("GSe < 50 kW") customer consuming 1000 kWh, 2000 kWh and 15,000 kWh monthly is determined based on the forecast increase in the customer's Retail Transmission Service Rates ("RTSR") as detailed below in Table 4.

Table 4: 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 Jan 1, 2016[1]	$ 262.79	$ 492.00	$ 3,471.80
RTSR included in 2016 GSe Customer's Bill	$ 10.19	$ 20.39	$ 152.89
Estimated 2017 Monthly RTSR[2]	$ 10.55	$ 21.11	$ 158.29
2017 increase in Monthly Bill	**$ 0.36**	**$ 0.72**	**$ 5.40**
2017 increase as a % of total bill	*0.1%*	*0.1%*	*0.2%*
Estimated 2018 Monthly RTSR[2]	$ 11.09	$ 22.18	$ 166.32
2018 increase in Monthly Bill	**$ 0.53**	**$ 1.07**	**$ 8.02**
2018 increase as a % of total bill	*0.2%*	*0.2%*	*0.2%*

[1] Total bill including HST, based on time-of-use RPP commodity pricing and 2016 distribution rates approved per Distribution Rate Order EB-2015-0079.
[2] The impact on RTSR is assumed to be the net impact on average transmission rates, as per Table 2, adjusted for Hydro One's revenue disbursement allocator per approved 2016 UTRs per EB-2015-0311.

CURRENT ONTARIO TRANSMISSION RATE SCHEDULES

The current Uniform Transmission Rate ("UTR") Schedules were approved under Decision on EB-2014-0140 dated December 2, 2014 with approved 2016 Rate Order under EB-2015-0311 dated January 14, 2016. 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: 2016 Ontario Uniform Transmission Rate Schedules
Attachment 2: 2016 Uniform Transmission Rates and Revenue Disbursement Allocators

2016 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-2015-0311

The rate schedules contained herein shall be effective January 1, 2016.

Issued: January 14, 2016
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.

TRANSMISSION RATE SCHEDULES

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 that 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 the 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 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

TRANSMISSION RATE SCHEDULES

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. 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.

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]	**3.66**
Line Connection Service Rate (PTS-L): $ Per kW of Line Connection Billing Demand[1,3]	**0.87**
Transformation Connection Service Rate (PTS-T): $ Per kW of Transformation Connection Billing Demand[1,3,4]	**2.02**

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 embedded generation 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. 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.

2016 Uniform Transmission Rates and Revenue Disbursement Allocators
(for Period January 1, 2016 to December 31, 2016)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,701,645	$878,728	$1,746,716	$6,327,089
CNPI	$2,608,113	$619,136	$1,230,705	$4,457,953
GLPT	$23,732,985	$5,633,935	$11,199,017	$40,565,936
H1N	$866,145,218	$205,612,810	$408,712,802	$1,480,470,830
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$929,153,107	$212,744,608	$422,889,239	$1,564,786,954

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	249,552.000	241,956.000	207,936.000	
B2MLP	0.000	0.000	0.000	
All Transmitters	253,760.250	245,453.342	209,196.700	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.66**	**0.87**	**2.02**	
	↓	↓	↓	
FNEI Allocation Factor	**0.00398**	**0.00413**	**0.00413**	
CNPI Allocation Factor	**0.00281**	**0.00291**	**0.00291**	
GLPT Allocation Factor	**0.02554**	**0.02648**	**0.02648**	
H1N Allocation Factor	**0.93219**	**0.96648**	**0.96648**	
B2MLP Allocation Factor	**0.03548**	**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-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.

Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.

Note 4: Hydro One Rates Revenue Requirement per Board Decision on Settlement Agreement for EB-2014-0140 dated December 4, 2014 and 2016 order issued January 14, 2016.

Note 5: B2MLP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.

PROPOSED ONTARIO TRANSMISSION RATE SCHEDULES

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 2017 Ontario Uniform Transmission Rate Schedule
Attachment 2: Proposed 2018 Ontario Uniform Transmission Rate Schedule
Attachment 3: Proposed 2017 and 2018 Uniform Transmission Rates and Revenue Disbursement Allocators

2017 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-201X-XXXX

The rate schedules contained herein shall be effective January 1, 2017

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):	**3.68**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.92**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.22**
$ 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 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.

2018 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULES

EB-201Y-YYYY

The rate schedules contained herein shall be effective January 1, 2018

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):	**3.86**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.97**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**2.33**
$ 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 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.

2017 Draft Uniform Transmission Rates and Revenue Disbursement Allocators

(Effective for period January 1, 2017 to December 31, 2017)

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI	$3,588,261	$900,913	$1,837,915	$6,327,089
CNPI	$2,528,224	$634,767	$1,294,962	$4,457,953
GLPT	$23,006,025	$5,776,176	$11,783,735	$40,565,936
H1N	$853,356,393	$214,254,171	$437,090,979	$1,504,701,543
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$915,444,049	$221,566,027	$452,007,591	$1,589,017,667

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	**Line Connection**	**Transformation Connection**	
FNEI	187.120	213.460	76.190	
CNPI	522.894	549.258	549.258	
GLPT	3,498.236	2,734.624	635.252	
H1N	244,865.656	236,890.824	202,461.050	
B2MLP	0.000	0.000	0.000	
All Transmitters	249,073.906	240,388.166	203,721.750	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.68**	**0.92**	**2.22**	
FNEI Allocation Factor	**0.00392**	**0.00407**	**0.00407**	
CNPI Allocation Factor	**0.00276**	**0.00286**	**0.00286**	
GLPT Allocation Factor	**0.02513**	**0.02607**	**0.02607**	
H1N Allocation Factor	**0.93218**	**0.96700**	**0.96700**	
B2MLP Allocation Factor	**0.03601**	**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-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.

Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.

Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.

Note 4: H1N Rates Revenue Requirement and Charge Determinants as proposed in application EB-2016-0160.

Note 5: B2M LP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.

Note 6: Calculated data in shaded cells.

1 **2018 Draft Uniform Transmission Rates and Revenue Disbursement Allocators**

2 (Effective for period January 1, 2018 to December 31, 2018)

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI	$3,587,559	$903,548	$1,835,982	$6,327,089
CNPI	$2,527,729	$636,624	$1,293,600	$4,457,953
GLPT	$23,001,523	$5,793,073	$11,771,340	$40,565,936
H1N	$898,899,737	$226,393,327	$460,024,073	$1,585,317,138
B2MLP	$32,965,146	$0	$0	$32,965,146
All Transmitters	$960,981,695	$233,726,572	$474,924,995	$1,669,633,262

Transmitter	Total Annual Charge Determinants (MW)*			
	Network	Line Connection	Transformation Connection	
FNEI	187.120	213.460	76.190	
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	249,132.407	240,445.584	203,770.823	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.86**	**0.97**	**2.33**	
FNEI Allocation Factor	**0.00373**	**0.00387**	**0.00387**	
CNPI Allocation Factor	**0.00263**	**0.00272**	**0.00272**	
GLPT Allocation Factor	**0.02394**	**0.02479**	**0.02479**	
H1N Allocation Factor	**0.93540**	**0.96862**	**0.96862**	
B2MLP Allocation Factor	**0.03430**	**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-2009-0387 dated December 9, 2010. Set as Interim on December 29, 2015 under EB-2015-0368.
Note 2: CNPI Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0204 dated June 25, 2015 and 2016 order under EB-2015-0354, issued January 14, 2016.
Note 3: GLPT Rates Revenue Requirement and Charge Determinants per OEB Decision EB-2014-0238, issued December 18, 2014 and 2016 order under EB-2015-0337, issued January 14, 2016.
Note 4: H1N Rates Revenue Requirement and Charge Determinants as proposed in application EB-2016-0160.
Note 5: B2M LP 2016 Revenue Requirement per Board Decision and Order EB-2015-0026 dated December 29, 2015. 2016 Rate Order approved on January 14, 2016.
3 *Note 6: Calculated data in shaded cells.*

CURRENT WHOLESALE METER SERVICE AND EXIT FEE SCHEDULE

The current Wholesale Meter Service and Exit Fee Schedule was approved under Decision on EB-2014-0140 dated December 2, 2014 with approved 2016 Rate Order under EB-2015-0311 dated January 14, 2016. This approved schedule is included in the following attachment.

Attachment 1: Wholesale Meter Service and Exit Fee Schedule

HYDRO ONE NETWORKS INC.
Ontario, Canada

WHOLESALE METER SERVICE
And
EXIT FEE SCHEDULE

Rate Schedule: HON-MET
Issued: To be determined
Ontario Energy Board

RATE SCHEDULE: HON-MET	HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

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

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

a) Wholesale Meter Service

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

The Wholesale Meter Service rate covered by this schedule shall remain in place until such time as the rate is revised by Order of the Ontario Energy Board.

b) Fee for Exit from Transitional Arrangement

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

PROPOSED WHOLESALE METER SERVICE AND EXIT FEE SCHEDULE

The Wholesale Meter Service and Exit Fee Schedule provided in an attachment to this exhibit reflects Hydro One's proposal for establishing an annual fee approach to wholesale meter services, as documented in Exhibit H1, Tab 3, Schedule 1; which will result in rates consistent with the current Wholesale Meter Service and Exit Fee Schedule in Exhibit H2, Tab 2, Schedule 1.

Attachment 1: Hydro One Network Inc. Proposed Wholesale Meter Service and Exit Fee Schedule

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

	HYDRO ONE NETWORKS - WHOLESALE METER SERVICE

APPLICABILITY:

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

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

a) Fee for Wholesale Meter Service

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

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

b) Fee for Exit from Transitional Arrangement

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