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BY EMAIL AND RESS

November 28, 2024

Ms. Nancy Marconi
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Ms. Marconi,

EB-2024-0117 – Niagara Reinforcement Limited Partnership (NRLP) – 2025-2029 Transmission Revenue Requirement – Draft Revenue Requirement and Charge Determinant Order

Hydro One Networks Inc., on behalf of Niagara Reinforcement Limited Partnership (NRLP), is submitting NRLP's Draft Revenue Requirement and Charge Determinant Order for its five-year Transmission Revenue Requirement Application for the period 2025-2029 using the Ontario Energy Board's (OEB) Regulatory Electronic Submission System.

On November 21, 2024, the OEB issued its decision on 2025-2029 transmission revenue requirement for NRLP, accepting the settlement proposal as filed (the "Decision").

In issuing the Decision, the OEB directed NRLP to update its 2025 revenue requirement and bill impact calculations based on the OEB's 2025 cost of capital parameters, and that NRLP reflect those updates in its Draft Revenue Requirement and Charge Determinant Order when filed.

The OEB also specified that the Draft Revenue Requirement and Charge Determinant Order shall incorporate the OEB's findings in the Decision, complete with detailed calculations and supporting materials, including:

- Revised 2025 electricity transmission revenue requirement; and
- Total bill impacts for a transmission customer and for typical retail customers (Hydro One Residential R1 customer consuming 750 kW per month and Hydro One energy-billed General Service GS<50 kW customer consuming 2,000 kWh per month)

1. Revenue Requirement and Charge Determinants

After updating the revenue requirement to reflect the 2025 cost of capital parameters, NRLP's total 2025 to 2029 revenue requirements are provided in Table 1 as follows:

Table 1 - Settled 2025-2029 Rates Revenue Requirement ($M)[1]

	2025	2026	2027	2028	2029
Proposed Revenue Requirement	**8.99**	**8.94**	**8.82**	**8.81**	**9.49**
Settlement Reduction	(0.03)	(0.03)	(0.03)	(0.04)	(0.06)
Settled Revenue Requirement	**8.96**	**8.91**	**8.79**	**8.77**	**9.43**
Settled Revenue Requirement – Updated with OEB's 2025 Cost of Capital Parameters[2]	**8.90**	**8.85**	**8.73**	**8.71**	**9.37**
Add: DVA Disposition	(0.58)				
Settled Rates Revenue Requirement	**8.31**	**8.85**	**8.73**	**8.71**	**9.37**

Under the agreed-upon revenue requirement framework, there is no longer a requirement to file annual update applications with the OEB throughout the term; however, there will be a one-time update application in 2025 to update the cost of long-term debt based on actual issuances in 2025. This will update and set the revenue requirements, effective on January 1 each year, for the remaining term from 2026 through to 2029.

NRLP does not have any customer delivery points supplied directly from its assets, and as such NRLP does not have charge determinants for setting Uniform Transmission Rates (UTRs).

2. UTR Calculations and Bill Impacts

The Decision determined that NRLP's approved 2025 revenue requirement will be incorporated into the 2025 UTRs. The change in NRLP's rates revenue requirement will decrease the 2024 Network UTR from $5.78/kW[3] to $5.77/kW effective January 1, 2025. The Line Connection and Transformation Connection UTRs are unaffected by NRLP. NRLP's approved 2025 revenue requirement to establish the proposed 2025 UTRs and revenue disbursement allocators are provided in Attachments 4 and 5. The updated bill impacts are provided in Table 2 as follows:

[1] Update to Table 1 of Settlement Proposal approved in EB-2024-0117, Decision and Order, issued November 21, 2024.

[2] See Attachment 1 of Draft Revenue Requirement and Charge Determinant Order

[3] EB-2023-0222, Decision and Rate Order on 2024 Uniform Transmission Rates, January 18, 2024.

Table 2 - Summary of Impacts on Average Transmission Rates and Transmission and Distribution-Connected Customers

	2024	2025	2026	2027	2028	2029
Rates Revenue Requirement ($M)	8.565	8.314	8.845	8.726	8.707	9.369
Net Impact on Average Transmission Rates		-0.011%	0.024%	-0.005%	-0.001%	0.029%
Average Transmission Customer Total Bill Impact		-0.001%	0.003%	-0.001%	0.000%	0.003%
Typical Hydro One Distribution R1 Customer Total Bill Impact (750 kWh)		$(0.002)	$ 0.004	$(0.001)	$(0.000)	$ 0.005
		-0.001%	0.003%	-0.001%	0.000%	0.003%
Typical Hydro One Distribution GS<50kW Customer Total Bill Impact (2000 kWh)		$(0.004)	$ 0.008	$(0.002)	$(0.000)	$ 0.010
		-0.001%	0.002%	0.000%	0.000%	0.002%

Note: NRLP's rates revenue requirement impacts reflect its share of the transmission rates revenue requirement in UTRs.

3. Supporting Material

As part of NRLP’s draft Revenue Requirement and Charge Determinant Order, the following attachments are provided:

Attachment 1: Exhibit E-01-01-01 (Calculation of Revenue Requirement – UPDATED)
Attachment 2: Exhibit G-01-02 (Cost of Long Term Debt - UPDATED)
Attachment 3: Exhibit G-01-03 (Capital Structure - UPDATED)
Attachment 4: Exhibit I-04-01-01 (Proposed 2025 Uniform Transmission Rate Schedules – UPDATED)
Attachment 5: Exhibit I-04-01-02 (Proposed 2025 Uniform Transmission Rates and Revenue Disbursement Allocators – UPDATED)

Sincerely,

Kathleen Burke

NRLP
Calculation of Revenue Requirement (2025 to 2029)
Year Ending December 31
($ Millions)

Line No.	Particulars		Test 2025 (a)	Test 2026 (b)	Test 2027 (c)	Test 2028 (d)	Test 2029 (e)
	Cost of Service						
1	Operating, maintenance & administrative	$	1.0	1.0	1.0	1.1	1.8
2	Depreciation		1.6	1.6	1.6	1.6	1.6
3	Income taxes		0.1	0.1	0.1	0.1	0.1
4	Cost of service excluding return on capital	$	2.7	2.7	2.7	2.8	3.5
5	Return on capital		6.2	6.1	6.0	5.9	5.9
6	Total revenue requirement	$	8.9	8.8	8.7	8.7	9.4

Niagara Reinforcement Limited Partnership
Cost of Long-Term Debt Capital
Test Year (2025)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed Total Amount ($Millions)	Net Capital Employed Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding at 12/31/2024 ($Millions)	Total Amount Outstanding at 12/31/2025 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	30-Apr-20	1.780%	28-Feb-25	20.3	0.1	20.2	99.63	1.86%	20.3	0.0	3.1	0.1	
2	30-Apr-20	2.180%	28-Feb-30	24.3	0.1	24.2	99.58	2.23%	24.3	23.9	23.9	0.5	
3	30-Apr-20	2.730%	28-Feb-50	18.2	0.1	18.1	99.42	2.76%	18.2	18.2	18.2	0.5	
4	25-Feb-25	4.197%	25-Feb-35	20.3	0.1	20.2	99.50	4.26%	0.0	19.8	17.0	0.7	
5		**Subtotal**							62.9	62.0	62.3	1.8	
6		Treasury OM&A costs										0.02	
7		Other financing-related fees										0.05	
8		**Total**							62.9	62.0	62.3	1.9	3.02%

Note 1 - All debt is 3rd party issued debt with fixed rates
Note 2 - Principal amount offered for debt in line 2 has been updated to reflect the principal amount outstanding at the start of 2025

Niagara Reinforcement Limited Partnership
Cost of Long-Term Debt Capital
Test Year (2026)
Year ending December 31

Line No.	Offering Date	Coupon Rate	Maturity Date	Principal Amount Offered ($Millions)	Premium Discount and Expenses ($Millions)	Net Capital Employed: Total Amount ($Millions)	Net Capital Employed: Per $100 Principal Amount (Dollars)	Effective Cost Rate	Total Amount Outstanding: at 12/31/2025 ($Millions)	Total Amount Outstanding: at 12/31/2026 ($Millions)	Avg. Monthly Averages ($Millions)	Carrying Cost ($Millions)	Projected Average Embedded Cost Rates
	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)	(m)
1	30-Apr-20	2.180%	28-Feb-30	23.9	0.1	23.8	99.58	2.23%	23.9	23.9	23.9	0.5	
2	30-Apr-20	2.730%	28-Feb-50	18.2	0.1	18.1	99.42	2.76%	18.2	18.2	18.2	0.5	
3	25-Feb-25	4.197%	25-Feb-35	19.8	0.1	19.7	99.50	4.26%	19.8	18.9	19.4	0.8	
4		**Subtotal**							62.0	61.0	61.5	1.9	
5		Treasury OM&A costs										0.02	
6		Other financing-related fees										0.05	
7		**Total**							62.0	61.0	61.5	1.9	3.13%

Note 1 - All debt is 3rd party issued debt with fixed rates

NRLP
Debt and Equity Summary
Historical Years (2019, 2020, 2021, 2022, 2023) and Bridge Year (2024)
As at December 31
($ Millions)

Updated Line No.	Particulars	Amount Outstanding 2019 Actual	Amount Outstanding 2020 Actual	Amount Outstanding 2021 Actual	Amount Outstanding 2022 Actual	Amount Outstanding 2023 Actual	Amount Outstanding 2024 Bridge
		(a)	(a)	(b)	(c)	(d)	(e)
I	Long-term debt	66.9	66.9	65.5	64.7	63.8	62.9
2	Short-term debt	4.8	4.8	4.7	4.6	4.6	4.5
3	Preference shares	-	-	-	-	-	-
4	Common equity	49.1	48.8	49.3	46.9	46.2	44.6

NRLP
Summary of Cost of Capital
Test Year 2025
Utility Capital Structure
Year Ending December 31
($ Millions)

		2025			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	62.3	56.7%	3.02%	1.88
2	Short-term debt	4.4	4.0%	5.04%	0.22
3	Deemed long-term debt	(0.7)	(0.7%)	3.02%	(0.02)
4	Total debt	66.0	60.0%	3.16%	2.08
5	Common equity	44.0	40.0%	9.25%	4.07
6	Total rate base	109.9	100.0%	5.59%	6.15

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2025 Cost of Capital Parameters
Common Equity % based on OEB's 2025 Cost of Capital Parameters
Total rate base from C-01-01

NRLP
Summary of Cost of Capital
Test Year 2026
Utility Capital Structure
Year Ending December 31
($ Millions)

Line No.	Particulars	2026 ($M) (a)	% (b)	Cost Rate (%) (c)	Return ($M) (d)
I	Long-term debt	61.5	56.8%	3.13%	1.93
2	Short-term debt	4.3	4.0%	5.04%	0.22
3	Deemed long-term debt	(0.8)	(0.8%)	3.13%	(0.03)
4	Total debt	65.0	60.0%	3.26%	2.12
5	Common equity	43.3	40.0%	9.25%	4.01
6	Total rate base	108.4	100.0%	5.65%	6.13

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2025 Cost of Capital Parameters
Common Equity % based on OEB's 2025 Cost of Capital Parameters
Total rate base from C-01-01

NRLP
Summary of Cost of Capital
Test Year 2027
Utility Capital Structure
Year Ending December 31
($ Millions)

		2027			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	60.6	56.8%	3.13%	1.90
2	Short-term debt	4.3	4.0%	5.04%	0.22
3	Deemed long-term debt	(0.8)	(0.8%)	3.13%	(0.03)
4	Total debt	64.0	60.0%	3.26%	2.09
5	Common equity	42.7	40.0%	9.25%	3.95
6	Total rate base	106.7	100.0%	5.65%	6.04

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2025 Cost of Capital Parameters
Common Equity % based on OEB's 2025 Cost of Capital Parameters
Total rate base from C-01-01

NRLP
Summary of Cost of Capital
Test Year 2028
Utility Capital Structure
Year Ending December 31
($ Millions)

		2028			
Line No.	Particulars	($M)	%	Cost Rate (%)	Return ($M)
		(a)	(b)	(c)	(d)
I	Long-term debt	59.7	56.8%	3.13%	1.87
2	Short-term debt	4.2	4.0%	5.04%	0.21
3	Deemed long-term debt	(0.8)	(0.8%)	3.13%	(0.03)
4	Total debt	63.1	60.0%	3.26%	2.05
5	Common equity	42.0	40.0%	9.25%	3.89
6	Total rate base	105.1	100.0%	5.65%	5.94

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2025 Cost of Capital Parameters
Common Equity % based on OEB's 2025 Cost of Capital Parameters
Total rate base from C-01-01

NRLP
Summary of Cost of Capital
Test Year 2029
Utility Capital Structure
Year Ending December 31
($ Millions)

		2029			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	58.8	56.8%	3.13%	1.84
2	Short-term debt	4.1	4.0%	5.04%	0.21
3	Deemed long-term debt	(0.8)	(0.8%)	3.13%	(0.03)
4	Total debt	62.1	60.0%	3.26%	2.02
5	Common equity	41.4	40.0%	9.25%	3.83
6	Total rate base	103.5	100.0%	5.65%	5.85

Long term debt ($M) based on Average Monthly Total Debt outstanding G-01-02
Long term debt % based on Projected Average Embedded Cost Rate G-01-02
Short term debt % based on OEB's 2025 Cost of Capital Parameters
Common Equity % based on OEB's 2025 Cost of Capital Parameters
Total rate base from C-01-01

NRLP
Summary of Cost of Capital
Last OEB-approved year (2020)
Utility Capital Structure
Year Ending December 31
($ Millions)

		2020			
Line No.	**Particulars**	**($M)**	**%**	**Cost Rate (%)**	**Return ($M)**
		(a)	(b)	(c)	(d)
I	Long-term debt	66.0	56.0%	3.05%	2.0
2	Short-term debt	4.7	4.0%	2.75%	0.1
3	Deemed long-term debt	-	0.0%	3.05%	0.0
4	Total debt	70.7	60.0%	3.03%	2.1
5	Common equity	47.1	40.0%	8.52%	4.0
6	Total rate base	117.8	100.0%	5.23%	6.2

SCHEDULE B

2025 UNIFORM TRANSMISSION RATE SCHEDULE

DECISION AND RATE ORDER

EB-2024-XXXX

MONTH DD, YYYY

2025 ONTARIO UNIFORM TRANSMISSION RATE SCHEDULE

EB-2024-XXXX

The rates contained herein shall be implemented effective January 1, 2025

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

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

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

RATE SCHEDULE: (PTS) PROVINCIAL TRANSMISSION RATES

APPLICABILITY:

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

	Monthly Rate ($ per kW)
Network Service Rate (PTS-N):	**5.77**
$ Per kW of Network Billing Demand [1,2]	
Line Connection Service Rate (PTS-L):	**0.95**
$ Per kW of Line Connection Billing Demand [1,3]	
Transformation Connection Service Rate (PTS-T):	**3.21**
$ 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):	$1.78 / 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.

SCHEDULE A

2025 REVENUE DISBURSEMENT ALLOCATOR

DECISION AND RATE ORDER

EB-2024-XXXX

MONTH DD, YYYY

Uniform Transmission Rates and Revenue Disbursement Allocators
Effective January 1, 2025

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
Hydro One	$1,206,861,187	$212,168,826	$605,276,749	$2,024,306,762
HOSSM	$25,645,763	$4,508,581	$12,862,112	$43,016,456
FNEI	$4,762,380	$837,237	$2,388,475	$7,988,092
CNPI	$2,770,591	$487,076	$1,389,534	$4,647,201
WPLP	$33,585,573	$0	$0	$33,585,573
EWTLP	$54,921,609	$0	$0	$54,921,609
B2MLP	$36,395,939	$0	$0	$36,395,939
NRLP	$8,314,329	$0	$0	$8,314,329
All Transmitters	$1,373,257,371	$218,001,720	$621,916,870	$2,213,175,961
Transmitter	**Total Annual Charge Determinants (MW)***			
	Network	**Line Connection**	**Transformation Connection**	
Hydro One	233,393.428	226,543.453	192,711.042	
HOSSM	3,498.236	2,734.624	635.252	
FNEI	230.410	248.860	73.040	
CNPI	522.894	549.258	549.258	
WPLP	156.151	0.000	0.000	
EWTLP	0.000	0.000	0.000	
B2MLP	0.000	0.000	0.000	
NRLP	0.000	0.000	0.000	
All Transmitters	237,801.119	230,076.195	193,968.592	
Transmitter				
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**5.77**	**0.95**	**3.21**	
Hydro One Allocation Factor	**0.87883**	**0.97325**	**0.97325**	
HOSSM Allocation Factor	**0.01868**	**0.02068**	**0.02068**	
FNEI Allocation Factor	**0.00347**	**0.00384**	**0.00384**	
CNPI Allocation Factor	**0.00202**	**0.00223**	**0.00223**	
WPLP Allocation Factor	**0.02446**	**0.00000**	**0.00000**	
EWTLP Allocation Factor	**0.03999**	**0.00000**	**0.00000**	
B2MLP Allocation Factor	**0.02650**	**0.00000**	**0.00000**	
NRLP Allocation Factor	**0.00605**	**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: Hydro One Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0127 dated September 19, 2023.
Note 2: HOSSM Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0130 dated October 24, 2023.
Note 3: FNEI Revenue Requirement and Charge Determinants per OEB Revenue Requirement and Charge Determinant Order EB-2016-0231 dated January 18, 2018.
Note 4: CNPI Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2015-0354 dated January 14, 2016.
Note 5: WPLP Revenue Requirement and Charge Determinants per OEB Decision and Order EB-2023-0168 dated November 30, 2023.
Note 6: EWTLP Revenue Requirement per OEB Decision and Order EB-2023-0298, Upper Canada Transmission 2, Inc. dated December 12, 2023.
Note 7: B2MLP Revenue Requirement per OEB Decision and Order EB-2023-0129 dated September 7, 2023.
Note 8: NRLP Revenue Requirement per Table 1.
Note 9: The revenue requirements of HOSSM, FNEI, and CNPI are allocated to the three transmission rate pools on the same basis as is used for Hydro One. The revenue requirements of WPLP, EWTLP, B2MLP and NRLP are allocated entirely to the Network rate pool. The total revenue requirements for each of the three transmission rate pools are then divided by the total charge determinants for each rate pool to establish the UTRs to two decimal places. The IESO uses the revenue collected from the UTRs to settle on a monthly basis with all rate-regulated transmitters using the revenue allocation factors.
Note 10: The allocation factors for each transmitter other than Hydro One are calculated by dividing each transmitter’s revenue requirement assigned to each transmission rate pool by the total transmitters revenue requirement for each rate pool. The allocation factors are rounded to five decimal places for each transmitter. The sum of these individual transmitter allocation factors is then deducted from 1.0 to determine the allocation factor for Hydro One.