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BY EMAIL AND RESS

July 31, 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 – 2025-2029 Transmission Revenue Requirement – Amended as-filed evidence

Hydro One Networks Inc., on behalf of Niagara Reinforcement Limited Partnership (NRLP), is submitting an amendment to NRLP's as-filed evidence to reflect a correction to the depreciation expense and subsequent changes to the components of the revenue requirement requested for approval in this Application.

NRLP is also using this opportunity to file an updated DVA Continuity Schedule to align the adjustments affecting the ESM balance to the year it relates. This has updated the ESM balance requested for disposition and has been incorporated in the revised UTRs to be collected from customers.

A summary of the key changes to the evidence is as follows:

Revised exhibit	Description of change	Key numerical impacts	How change is indicated in evidence
Exhibit A-01-01	To indicate updated exhibits in the amended application and filing of a custom depreciation study in Exhibit F-05-01, Attachment 3	N/A	N/A
Exhibit A-02-02	To reflect updated materiality threshold	Updated from $44k to $45k	Side-bar
Exhibit A-03-01	To reflect updated revenue requirement, rate base and return on capital tables in Executive Summary	Updates to Tables 2, 4, 7 and 9	Side-bar
Exhibit C-01-01	To reflect updated rate base tables in the exhibit	Updated from $110-104M to $109.9-103.5M (2025-29)	Side-bar

Exhibit C-01-01, Attachments 2 to 5 (excel)	To reflect updated accumulated depreciation, fixed asset continuities and average rate base	Various updates from 2025-29	Cells are highlighted in yellow[1]
Exhibit E-01-01	To reflect updated revenue requirement tables over the test period	Updated from $8.2-9.4M to $8.4-9.5M (2025-29)	Side-bar
Exhibit E-01-01, Attachment 1 (excel)	To re-file revenue requirement tables based on updated depreciation, tax and cost of capital	Various updates from 2025-29	Cells are highlighted in yellow
Exhibit F-01-01	To reflect updates to certain tables related to depreciation and tax	Updates to Table 1	Side-bar
Exhibit F-05-01	To reflect updated methodology to calculate depreciation expense, due to use of NRLP specific depreciation rates	Updated from $1.5M to $1.6M (2025-29)	Side-bar
Exhibit F-05-01, Attachments 1 and 2 (excel)	To re-file depreciation tables based on revised depreciation rates by asset class, as supported by the depreciation study filed in Exhibit F-05-01, Attachment 3	Various updates from 2025-29	Cells are highlighted in yellow
Exhibit F-06-01, Attachment 1 (excel)	To re-file tax calculations due to changes to depreciation expense	Various updates from 2025-29	Cells are highlighted in yellow
Exhibit G-01-02 (excel)	To re-file updated cost of long-term debt due to changes in rate base	Various updates from 2025-29	Cells are highlighted in yellow[2]
Exhibit G-01-03 (excel)	To re-file updated cost of capital parameters due to changes in rate base	Various updates from 2025-29	Cells are highlighted in yellow
Exhibit H-01-01	To update the NRLP ESM balance requested for disposition	Updated Table 1	Side-bar
Exhibit H-01-01, Attachment 1	To re-file NRLP's DVA continuity Schedule to reflect 2022 and 2023 year-end principal adjustment in the 2022 and 2023 ESM balances, respectively, to apply applicable adjustments to the year it relates	The impact on the ESM is a total principal reduction of $34K from ($570,000) to ($535,761) due to the inclusion of the 2023 adjustment in the 2023 year-end ESM balance	Cells are highlighted in grey
Exhibit I-01-01	To reflect updated 2025-29 rates revenue requirement for the purposes of setting UTRs	Updated from $8.24-9.39M to $8.40-9.49M (2025-29)	Side-bar

[1] Hydro One has only highlighted changes if a number has changed when rounded to one decimal place.
[2] G-01-02 also has cells highlighted in grey to indicate a minor correction unrelated to the depreciation expense correction.

Exhibit I-02-01	To reflect updated impacts on the current total bill for average transmission-connected customers and distribution-customer customers	Updated Tables 2 and 3	Side-bar
Exhibit I-04-01	Cover page to reflect updated Attachments 1 and 2 (proposed 2025 UTRs and revenue disbursement allocators)	N/A	Side-bar
Exhibit I-04-01, Attachment 1	To reflect updated Network Service Rate resulting from the change in rates revenue requirement	Updated form $5.77/kW to $5.78/kW	Side-bar
Exhibit I-04-01, Attachment 2	To reflect updated impacts on NRLP and total Network revenue requirement and Network revenue disbursement allocators for all transmitters	Various updates as indicated in UTR schedule	Side-bar

An electronic copy of the amended as-filed evidence has been submitted using the Board's Regulatory Electronic Submission System.

Sincerely,

Kathleen Burke

Kathleen Burke

EXHIBIT LIST

Exhibit	Tab	Schedule	Attachment	Contents
A				**Administration**
A	1	1		Exhibit List (UPDATED)
A	2	1		Application
A	2	1	1	Certification of Evidence
A	2	1	2	Certification of Deferral and Variance Account Balances
A	2	2		Compliance with Applicable Filing Requirements (UPDATED)
A	2	2	1	Filing Requirement Checklist
A	2	3		Summary of OEB Directives and Undertakings from Previous Proceedings
A	3	1		Executive Summary (UPDATED)
A	4	1		Revenue Requirement Framework Summary
A	5	1		Description of the Partnership
A	6	1		Financial Information
A	6	1	1	EB 2018-0275 Transmission Accounting Order – NRP Transmission Line Revenue Requirement Deferral Account
A	6	1	2	Transmission Accounting Order – Tax Rule and Rule Changes Variance Account
A	6	1	3	Transmission Accounting Order – Earnings Sharing Mechanism Deferral Account
A	6	2		NRLP Financial Statements - Historical Years
A	6	2	1	2023 NRLP Financial Statements
A	6	2	2	2022 NRLP Financial Statements
A	6	3		Reconciliation of Regulatory Financial Results with Audited Financial Statements (2023)

COMPLIANCE WITH APPLICABLE FILING REQUIREMENTS

1.0 INTRODUCTION

NRLP has prepared this Application in accordance with the OEB's guidance in its *Filing Requirements for Electricity Transmission Rate Applications* (February 11, 2016) (Transmission Filing Requirements). NRLP has presented the content to align with Chapter 2 of the Transmission Filing Requirements (Chapter 2). To assist the OEB in its review of the Application, NRLP has prepared a checklist of the Transmission Filing Requirements including the relevant evidentiary references for each item. This checklist is provided as Attachment 1 to this Exhibit.

2.0 NON-APPLICABLE FILING REQUIREMENTS

Given that NRLP is a single transmission line asset and has a limited role in the transmission of electricity in the province, the following Transmission Filing Requirements are not applicable. These include:

1. Customer Engagement

- NRLP does not have any direct customers, and hence has not performed any customer engagement activities and analysis.

2. Transmission System Plan

- NRLP has prepared an abridged Transmission System Plan (TSP) given that it is proposing minimal capital expenditures during the rate period.

- Section 2.4 of Chapter 2 states that transmitters may wish to refer to Chapter 5 of the OEB's Filing Requirements for Electricity Distributors, Consolidated Distribution System Plan Filing Requirements (DSP Requirements) for further guidance on the content and structure of a TSP. NRLP has referred to the DSP Requirements to guide the preparation of its abridged TSP.

3. Working Capital Allowance

- In B2M LP's previous transmission rates application (EB-2015-0026), it was established and that there is no need for a working capital allowance given the that timing of the payments and revenue could be organised by the General Partner to effectively ameliorate any meaningful lead or lag on those cash flows. The same situation applies for NRLP and therefore there is no request for a working capital allowance to be included in rate base.

4. Capitalization of Overhead

- NRLP LP does not have significant projects under construction, so there are no interest or overhead capitalized.

Economic Overview / Load Forecast

- NRLP's asset base consists of one 230 kV transmission line comprised of two circuits with no delivery points. Hence, NRLP has no discrete, incremental load determinants to include in the UTR forecast.

- The only rate pool applicable for NRLP assets is the "Network" pool. Therefore, no further cost allocation methodology is presented in this Application.

Other Revenue

- NRLP has no external revenue sources. The only revenue applicable to NRLP is the revenue requirement from owning and maintaining its 230 kV transmission line.

Employee Compensation

- NRLP has no employees. Operations and management services are provided by Hydro One via a service level agreement as outlined in Exhibit F-03-01.

3.0 MATERIALITY THRESHOLD

In terms of the materiality used by NRLP, 0.5% of the average of 5 years of the revenue requirement in the revenue requirement period of $45k is applicable.

4.0 DEVIATIONS FROM THE FILING REQUIREMENTS

NRLP has complied with the OEB's policies and guidelines as set out in the Transmission Filing Requirements.

5.0 CHANGES TO METHODOLOGIES USED IN PREVIOUS APPLICATIONS

NRLP includes a list of changes to its methodology compared to previous rebasing applications:

1. Change to methodology proposed to set transmission revenue requirement as further described in Exhibit A-04-01; and
2. Adoption of the new depreciation methodology for its assets consistent with the new depreciation methodology approved for HONI in EB-2023-0110 for 2023-27 distribution and transmission rates, as further described in Exhibit F-05-01.

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EXECUTIVE SUMMARY

This exhibit describes the key aspects of Niagara Reinforcement Limited Partnership (NRLP)'s application (the Application) in respect of its proposed transmission revenue requirement for 2025 to 2029.

1.0 NIAGARA REINFORCEMENT LIMITED PARTNERSHIP

NRLP is a limited partnership between Hydro One Indigenous Partnerships GP Inc. (HOIP) and Hydro One Networks Inc. (HONI), both of which are affiliates of Hydro One Inc. (HOI), and Six Nations of the Grand River Development Corporation (SNGRDC), and the Mississaugas of the Credit First Nation (MCFN).

NRLP's transmission system consists of a 230kV double circuit line from Allanburg TS to Middleport TS. Each circuit is approximately 76 km in length. HONI owns the terminating stations and line junctions (Allanburg TS, Middleport TS, and Allanburg West Junction).

2.0 APPROVALS REQUESTED

In this Application for 2025 to 2029 transmission revenue requirement, NRLP is requesting the Ontario Energy Board's (OEB) approval for:[1]

i. Revenue requirement for 2025-2029 period;
ii. Inclusion of NRLP's approved rates revenue requirement in the OEB's determination of the 2025 to 2029 Network pool of the Uniform Transmission Rates (UTRs);
iii. The continuation of NRLP's current regulatory accounts;
iv. Disposition of the Earnings Sharing Mechanism (ESM) balance as part of its revenue requirement over a one-year period commencing January 1, 2025;
v. An effective date of January 1, 2025; and
vi. Other items that may be requested by NRLP in the course of this proceeding, and as may be granted by the OEB.

[1] As described in Exhibit A-02-01.

A number of internal and external challenges will need to be managed over the 2025 - 2029 period. They include:

a) Completion of a System Renewal capital project valued at $150k with planned in-service addition in 2025; and
b) Managing NRLP's Right-of-Way vegetation maintenance program, taking into consideration the six-year vegetation cycle. To optimize contracting of brush control work, all portions of NRLP Right of Ways were aligned to be on the same six-year cycle. As a result, majority of the maintenance costs will be incurred in 2029.

NRLP's Application will mitigate these challenges and ensure that NRLP's assets are managed efficiently and effectively.

The change in NRLP's rates revenue requirement will not affect the 2025 Network UTR relative to the current 2024 rate.[3] The Line Connection and Transformation Connection UTRs are unaffected by NRLP, as described in Section 5.9 below.

The 2025 change in rates revenue requirement will result in an average impact on transmission rates of -0.007% and a total bill impact of less than 0.01% (less than 1 cent per month) for a typical Hydro One Residential (R1) customer consuming 750 kW per month and, similarly, a total bill impact of less than 0.01% (less than 1 cent per month) for a typical Hydro One energy-billed General Service (GS<50kW) customer consuming 2,000 kWh per month. The annual changes 2026 to 2029 revenue requirement will also not materially impact the average transmission rates, or the total bills for Hydro One's typical R1 and GS<50kW customers. A summary is provided in Table 9, below and further details are provided in Exhibit I-02-01.

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

3.0 REVENUE REQUIREMENT FRAMEWORK

NRLP proposes to set its revenue requirement for a five-year period using a forecast of OM&A and capital costs for each of the five years. Customer protection mechanisms such as an earnings sharing mechanism (ESM) and off-ramps are proposed. Consistent with the OEB's *Handbook for Utility Rate Applications* (the Handbook), cost of capital is proposed to be fixed at 2025 levels subject only to one update to the cost of long-term debt.[4]

NRLP understands that the OEB's Renewed Regulatory Framework (RRF), as most recently set out in the Handbook, provides that electricity transmitters are to choose either Custom IR or a Revenue Cap IR.[5] However, the RRF was not conceived for a single-asset utility such as NRLP. Single-asset utilities typically have few, if any, capital expenditures in the years following the in-service of the new asset and their rate base declines over time. As a result, a revenue cap index framework, whereby the revenue requirement is updated each year by a factor based on inflation minus a productivity factor, may result in overearning for a single-asset utility. NRLP believes that its proposed approach will provide greater transparency to ratepayers in respect of its costs over the 2025-2029 period and will allow for its revenue requirement to be directly tied to its forecast costs over the entire period.

The approach has a number of benefits as described below in Sections 3.1, 3.2 and 3.3.

3.1 THE APPROACH DOES NOT DISCOURAGE PRODUCTIVITY

NRLP has few, if any opportunities to unilaterally achieve productivity improvements, regardless of the revenue requirement framework under which it is operating at any given time.

[4] As detailed in Exhibit G-01-01.
[5] Handbook page 24.

Specifically:

- NRLP owns and operates a single 230kV transmission line that is about 18 years old and has an expected service life of over 80 years. As these assets are new, they require lower OM&A in comparison to other transmitters. A small amount of capital expenditures ($0.15M) is forecasted during the rate period;
- Given that there are minimal forecast capital expenditures, NRLP's main controllable costs are maintenance and a small amount of administration. These costs are a small fraction of total costs and are significantly less than the non-controllable portions of NRLP's costs (Cost of Capital, Depreciation, Income Tax, Operations, Corporate Allocation). As a result, it is only in respect of a modest portion of OM&A costs that productivity can be achieved. Even in respect of the controllable portion of maintenance and administration costs:
    - NRLP's management and work programs are provided by a service level agreement, resulting in minimal overhead as well as qualified and flexible resources when needed, allowing NRLP to remain cost efficient; and
    - NRLP's service level agreement integrates HONI's productivity improvements into NRLP's maintenance operations.

As a result of the above, NRLP receives the benefit of HONI's productivity improvements in NRLP's maintenance operations, regardless of the regulatory framework under which NRLP operates.

3.2 PROTECTIONS FOR RATEPAYERS

The approach proposed has a number of protections for ratepayers, including an ESM, a Z-factor mechanism, an off-ramp mechanism and performance metrics.

EARNINGS SHARING MECHANISM (ESM)

Although significant overearning is not expected, NRLP proposes to share, with customers, 50% of any earnings that exceed the OEB-allowed regulatory return on equity (ROE) by more than 100 basis points in any year of the five-year term.

Z-FACTOR

NRLP is proposing, consistent with the Handbook, that the OEB's Z-factor mechanism be available over the term of this five-year Application. The criteria that would apply to the use of the Z-factor mechanism are detailed in exhibit A-04-01.

OFF-RAMPS

NRLP proposes to apply the OEB's existing off-ramp mechanism, a trigger mechanism with an annual return on equity dead band of plus or minus 300 basis points,[6] at which point a regulatory review of the revenue requirement arising from NRLP's five-year Application may be initiated.

PERFORMANCE METRICS

As detailed in Exhibit D-1-1, NRLP is proposing a number of performance measures which align with RRF outcomes. These measures protect customers by providing transparency in respect of the performance of NRLP's assets. They allow for verification that the assets are operated within the expected parameters and continue to serve the electricity consumers of Ontario effectively.

3.3 ANNUAL UPDATE APPLICATIONS WILL NOT BE REQUIRED

As a result of NRLP's proposed approach, annual updates to set the revenue requirements for 2026-2029 will not be required. Only one update is proposed to the cost of long-term debt in 2025 as detailed in Exhibit G-01-01 of this Application. Once the 2025 update for cost of long-term debt is complete (impacting 2026-2029 revenue requirements), NRLP's 2026, 2027, 2028 and 2029 revenue requirements will be final. As a result, the OEB can use these final revenue requirements approved to set 2026, 2027, 2028 and 2029 UTRs. NRLP believes its proposal helps advance regulatory efficiency by eliminating the need for annual updates.

[6] See Chapter 3 of Filing Requirements for Electricity Distribution Rate Applications, section 3.2.10.

4.0 NRLP'S STRATEGIC PLAN

NRLP's plan on which this Application is based was informed by its values and strategic objectives described in the section below.

NRLP is sensitive to and has considered the needs of provincial ratepayers that have expressed a desire for low rates and high reliability. NRLP's plan supports these general ratepayer objectives by proposing one system renewal capital project valued at $150k in order to mitigate safety risks, and a modest OM&A budget required to maintain NRLP's transmission reliability.

NRLP's asset management process, as well as capital expenditure and operation and maintenance expenses for 2025-2029 are further explained in Attachment 1 to Exhibit B-01-03.

4.1 NRLP'S VALUES AND STRATEGIC OBJECTIVES

NRLP, as part of the Hydro One family of companies, is driven primarily by the values of health and safety, and stewardship. NRLP's strategy and business values must operate with revenue that can balance the financing of investment in infrastructure while maintaining affordable and reliable service.

NRLP is 45% owned by First Nations over whose traditional territory the transmission line crosses. Respect for Indigenous peoples and their traditions is another key value of the partnership.

The five-year vision associated with NRLP's strategic objectives is shown in Table 1. In managing its transmission assets, NRLP is committed to meeting the OEB's Renewed Regulatory Framework (RRF) outcomes as demonstrated by the alignment of NRLP's strategic objectives to the RRF outcomes.

Table 1 - NRLP Strategic Objectives

RRF Outcomes	Strategic Objectives	Five-Year Vision
Customer Focus	Reliable Transmission	Maintain top-tier transmission reliability performance and improve long-term system reliability.
	Foster Indigenous Relationships	To foster positive relationships with the Indigenous communities of the partners.
Operational Effectiveness	Injury-Free	Ensure NRLP's operations and management services agreement is executed in accordance with good utility practice for employee and public safety.
	Cost Control	Secure a reasonable service agreement with Hydro One Networks Inc. that minimizes cost.
Public Policy Responsiveness	Public Policy Responsiveness	Support government objectives by delivering on obligations mandated by government through legislation and regulatory requirements.
	Protecting the Environment	Sustainably manage NRLP's environmental footprint.
Financial Performance	Owner's Value	Achieve the Regulated Return on Equity allowed by the Ontario Energy Board.
	Ratepayer Value	Plan and strategically execute responsible investment in rate base assets to ensure the safety and reliability of the grid while ensuring manageable and stable rate impacts over the course of the planning period.

5.0 KEY ELEMENTS OF THE APPLICATION

5.1 REVENUE REQUIREMENT

NRLP's proposed 2025-29 revenue requirements are shown in Table 2.

Table 2 - Revenue Requirement ($M) *

Components	2025	2026	2027	2028	2029
OM&A	1.1	1.1	1.0	1.1	1.9
Depreciation	1.6	1.6	1.6	1.6	1.6
Income Taxes	0.1	0.1	0.1	0.1	0.1
Return on Capital	6.2	6.2	6.1	6.0	5.9
Total Revenue Requirement	**9.0**	**8.9**	**8.8**	**8.8**	**9.5**
Deduct External Revenues and Other[7]	(0.6)	0.0	0.0	0.0	0.0
Rates Revenue Requirement	**8.4**	**8.9**	**8.8**	**8.8**	**9.5**

* Exhibit Reference: E-01-01, Table 1.

The drivers of the increase in the 2025 revenue requirement compared to the 2020 OEB approved test year is predominantly driven by higher cost of OM&A and debt given the maturity of NRLP's previous five-year long-term debt ($20.3 million), as further explained in Exhibit F-02-01 and Exhibit G-01-01, respectively.

5.2 BUDGETING ASSUMPTIONS

NRLP has assumed generally 2% inflation in its capital and OM&A budgets.

5.3 LOAD FORECAST

NRLP has included no load forecast, as it has no metering points or delivery points. All power transported using NRLP's assets are delivered to the final customer by another transmitter and thus is included in another transmitter's load forecast. The revenue requirement is allocated to the provincial Network rate pool, as all assets serve the Network with no Transformation or individual customer services. Once the revenue

[7] This comprises of the disposition of Earnings Sharing Mechanism (ESM) regulatory account

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

5.4 TRANSMISSION SYSTEM PLAN (TSP)

This section summarizes the major drivers and elements of NRLP's five-year TSP (Exhibit B-01-03, Attachment 1). NRLP has aligned its TSP in accordance with Chapter 2 of the Ontario Energy Board's (OEB) *Filing Requirements for Electricity Transmission Applications* published on February 11, 2016, with further guidance from Chapters 3 and 5 of the OEB's *Filing Requirements for Electricity Distribution Rate Applications* (*Incentive Rate-Setting Applications* and *Distribution System Plan*), revised on June 15, 2023 and December 15, 2022, respectively (together, the "Filing Requirements").

5.4.1 ASSET MANAGEMENT PROCESS

NRLP continues to retain HONI under a service level agreement (SLA) to plan, organize, and execute the operation and maintenance of the assets and provide certain corporate and administrative support services. NRLP relies upon HONI's asset management process. HONI has continued to implement several refinements in its asset strategies and investment assessment to improve upon its asset management process, as documented in Section 2.2 of Exhibit B-02-01 of OEB proceeding EB-2021-0110.

5.4.2 INVESTMENT PLANNING PROCESS

NRLP's operational needs are assessed by HONI on an annual basis and are incorporated into HONI's investment planning process to establish a plan that addresses those operational needs while minimizing rate impacts. This planning process ultimately forms part of the overall asset management process, which is aimed at identifying and scoping the optimal timing of capital investments and asset maintenance throughout the life cycle of assets.

5.4.3 CAPITAL EXPENDITURES

NRLP's transmission system is limited to the components of a 230kV double circuit transmission line. Given the relatively new vintage of this line, only one capital project is being planned over the 2025 to 2029 planning period. Details of this capital project are provided in Attachment 1 of Exhibit B-01-03, Section 4.3. Table 3 below summarizes NRLP's historical actuals and planned in-service additions by category over the TSP planning period.

Table 3 - Overall Plan ($M)

OEB Category	Historical Actuals				Bridge	Forecast				
	2020	2021	2022	2023	2024 Forecast	2025	2026	2027	2028	2029
System Access	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
System Renewal	0.0	0.0	0.0	0.0	0.0	0.15	0.0	0.0	0.0	0.0
System Service	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
General Plant	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total Capital	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**	**0.15**	**0.0**	**0.0**	**0.0**	**0.0**

All of NRLP's assets are less than 18 years old; therefore, little degradation has occurred, and these assets are considered to be in good condition.

5.5 RATE BASE

The requested rate base over the test period is provided in Table 4 below. Details are provided in Exhibit C-01-01. The 2025 rate base represents a $1.5M (1.3%) decrease over 2024 rate base.

Table 4 - Transmission Rate Base ($M) *

Description	2025	2026	2027	2028	2029
Mid-Year Gross Plant	119.5	119.6	119.6	119.6	119.6
Mid-Year Accumulated Depreciation	(9.6)	(11.2)	(12.8)	(14.5)	(16.1)
Mid-Year Net Plant	**109.9**	**108.4**	**106.7**	**105.1**	**103.5**
Cash Working Capital	0.0	0.0	0.0	0.0	0.0
Materials and Supply Inventory	0.0	0.0	0.0	0.0	0.0
Transmission Rate Base	**109.9**	**108.4**	**106.7**	**105.1**	**103.5**

* Exhibit Reference: C-1-1, Table 3

5.6 PERFORMANCE AND REPORTING

NRLP is proposing to continue to track its performance by utilizing the measures approved by the OEB in the NRLP Settlement Agreement in EB-2018-0275.

Given the nature of NRLP's assets, the performance of the equipment does not lend itself to applying the typical measures that might be in place for other transmitters. NRLP's assets consist solely of a 230kV double circuit transmission line and do not include any terminal breakers or other operable assets. The demarcation point of each of the circuits is at a tower outside of the station as noted in Exhibit B-01-01. NRLP does not have any customer delivery points (or meter assets), which are the basis of common reliability performance measures such as SAIDI and SAIFI. However, HONI's SAIDI and/or SAIFI values can be impacted by outages caused by NRLP assets. As a result, as per the Settlement Agreement in EB-2018-0275, NRLP is providing two additional performance metrics, which measure interruptions to Hydro One delivery points caused by NRLP's circuits (T-SAIDI NRLP Contribution and T-SAIFI NRLP Contribution). Since NRLP has no customers, no Customer Focus measures have been proposed. The performance measures, along with their associated RRF performance outcomes are shown in Table 5.

Table 5 - NRLP's Performance Measures

RRF Outcomes	Performance Measure
Operational Excellence	Average System Availability (%)
Operational Excellence	T-SAIDI NRLP Contribution
Operational Excellence	T-SAIFI NRLP Contribution
Operational Excellence	O&M Cost ($K) per circuit kilometer[8]
Public Policy Responsiveness	NERC Vegetation Compliance

Further details on the methods and measures as well as the historical performance and forecast targets are documented in Exhibit D-01-01.

5.7 OPERATIONS, MAINTENANCE AND ADMINISTRATION (OM&A)

NRLP is managed by its general partner, HOIP, which retains HONI under a SLA, to plan, organize, and execute the operation and maintenance of the assets and provide certain corporate and administrative support services as outlined in Exhibit F-03-01.

OM&A expenses are derived based upon the various work programs and functions performed by or on behalf of the Partnership. As outlined in Table 6 below, the average OM&A annualized forecast for the 2025 to 2029 period is $1.2M. The 2020 Test Year OM&A approved in EB-2018-0275 rate filing was $0.8M. This represents a $0.4M increase over the 2020 test year. The average annualized forecast OM&A spend for the 2020 to 2024 period is $0.8M which is on par with the 2020 Test Year approved OM&A of $0.8M.

Higher OM&A forecasts for the 2025 to 2029 period are primarily due to all portions of NRLP's Right of Way undergoing major vegetation maintenance in 2029. As outlined in Exhibit B-01-03, Attachment 1, Section 3.3.1, Routine Operation and Maintenance, Line Clearing and Brush Control are cyclic vegetation maintenance activities scheduled for Right of Ways every six years. These activities have significantly higher unit costs compared to other vegetation management and patrol activities.

[8] Circuit kms refer to total route kms multiplied by number of circuits per km. For NRLP, this is 76 kms x 2 circuits = 152 kms.

Starting in 2023, NRLP is also charged transfer pricing by HONI for the use of certain shared assets. The shared asset costs allocated to NRLP include those for major fixed assets and intangible assets, as well as minor fixed assets. Shared Asset Allocation is forecast to be $0.1M annually for the 2025 to 2029 period, and mainly relates to HONI's SAP system, an enterprise-wide system that integrates work management, finance, supply chain and other enterprise software. Use of these systems is required for HONI to coordinate and execute its asset management process and subsequent maintenance activities for NRLP.

Other Incremental Expenses include components that are directly incurred by NRLP and are outside of the SLA with HONI. These include components such as insurance, regulatory expenses, Managing Director costs, and other administrative expenses such as external fees, statutory remittances, and auditor costs. These expenses have been adjusted for inflation for the 2025 to 2029 forecast period.

Further details are presented in Exhibit F-02-01.

1 **Table 3 - Summary of OM&A ($M)***

	Historical												Bridge		Forecast				
	2020			2021			2022			2023			2024		2025	2026	2027	2028	2029
	Plan*	Actual	Var	Plan*	Actual	Var	Plan*	Actual	Var	Plan*	Actual	Var	Plan*	Fcst	Fcst	Fcst	Fcst	Fcst	Fcst
SLA Costs	0.5	0.4	(0.1)	0.5	0.3	(0.3)	0.5	0.3	(0.2)	0.5	0.7	0.2	0.6	0.8	0.5	0.6	0.5	0.6	1.4
Incremental Expenses	0.3	0.2	(0.1)	0.3	0.2	(0.1)	0.3	0.3	0.0	0.3	0.3	0.2	0.3	0.5	0.6	0.5	0.5	0.5	0.5
Total OM&A	**0.8**	**0.7**	**(0.2)**	**0.9**	**0.5**	**(0.3)**	**0.9**	**0.6**	**(0.2)**	**0.9**	**1.1**	**0.2**	**0.9**	**1.3**	**1.1**	**1.1**	**1.0**	**1.1**	**1.9**

* The Plan values reflect the test year values (2020) approved by the OEB as part of the previous rate application, EB-2018-0275, as escalated by approved Revenue Cap Index values.

5.8 COST OF CAPITAL

Details of the cost of capital summary for each year are provided in Exhibit G-01-03. Table 7 below summarizes the return on capital for the 2025-2029 test period.

Table 4 - 2025-2029 Return on Capital

	Return on Capital ($M)				
	2025	**2026**	**2027**	**2028**	**2029**
Long term debt	1.9	1.9	1.9	1.9	1.8
Short-term debt	0.3	0.3	0.3	0.3	0.3
Common Equity	4.0	4.0	3.9	3.9	3.8
Total	**6.2**	**6.2**	**6.1**	**6.0**	**5.9**

NRLP's deemed capital structure for rate-making purposes is 60% debt and 40% common equity of utility rate base, as affirmed by the OEB's Decision in NRLP's 2020 to 2024 transmission rate application (EB-2018-0275). The 60% debt component is comprised of 4% deemed short-term debt and 56% long-term debt.[9]

At the time of the Draft Rate Order (DRO) in this proceeding, NRLP intends to update the 2025 to 2029 revenue requirements based on the OEB's release of its 2025 cost of capital parameters to reflect: (a) the OEB-prescribed 2025 return on equity (ROE) and short-term debt rates; and (b) a long-term debt rate based on NRLP's forecast debt refinancing in 2025, using the September 2024 Consensus Forecast. The ROE and short-term debt rate parameters will remain fixed over the five-year rate term.

For the 2026 revenue requirement year, NRLP proposes a one-time update to the cost of long-term debt to reflect the actual market rate achieved on the long-term debt it will issue in 2025. This will allow actual debt issuances made to refinance maturing debt in 2025 to be reflected in the 2026 revenue requirement and through to the end of the rate term.

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[9] Consistent with the Report of the Board on the Cost of Capital for Ontario's Regulated Utilities (EB-2009-0084) and its subsequent Review of the Existing Methodology of the Cost of Capital for Ontario's Regulated Utilities, dated January 14, 2016.

Further details regarding the cost of capital can be found in Exhibit G-01-01.

5.9 COST ALLOCATION AND RATE DESIGN

All assets associated with NRLP are classified as Network assets, consistent with the cost allocation methodology approved by the OEB for NRLP in previous OEB proceeding, in EB-2018-0275. Accordingly, the total rates revenue requirement associated with NRLP's transmission assets will be allocated to the Network pool. Further details regarding the cost allocation and rate design are provided in Exhibit I-01-01.

5.10 DEFERRAL AND VARIANCE ACCOUNTS

NRLP is requesting to dispose of its regulatory balances in the ESM deferral account that accumulated between 2021 and 2023. NRLP is requesting to dispose of the ESM deferral account balance as part of its revenue requirement over a one-year period commencing January 1, 2025.

NRLP's regulatory account balances are summarized in Table 8 below:

Table 5 - Summary of Regulatory Account Balances ($)

Description	Principal Balance as at Dec. 31, 2023	Projected Interest up to Dec. 31, 2024	Total Balance
Tax Rate and Rule Changes Variance Account	0	0	0
Niagara Reinforcement Limited Partnership Deferral Account	0	0	0
ESM Deferral Account	**(535,761)**	**(50,288)**	**(586,049)**
Total Group 2 Balances	**(535,761)**	**(50,288)**	**(586,049)**

NRLP is requesting approval to continue all existing accounts as detailed in Exhibit H-01-01.

5.11 BILL IMPACTS

A summary of the estimated impacts of this Application on average transmission rates and total bills for transmission and distribution-connected customers is provided in Table 9. Detailed calculations are provided in Exhibit I-02-01.

The total bill impact for a typical Hydro One residential (R1) customer consuming 750 kWh, and for a typical Hydro One General Service (GS<50kW) customer consuming 2,000 kWh is determined based on the forecast increase in the customer's Network Retail Transmission Service Rates (RTSR-N).

Table 9 - Summary of Impacts on Average Transmission Rates and Transmission and Distribution-Connected Customers

	2024	2025	2026	2027	2028	2029
NRLP's Rates Revenue Requirement ($M)	8.565	8.405	8.942	8.822	8.806	9.492
Net Impact on Average Transmission Rates		-0.007%	0.024%	-0.005%	-0.001%	0.030%
Average Transmission Customer Total Bill Impact		-0.001%	0.003%	-0.001%	0.000%	0.004%
Typical Hydro One Distribution R1 Customer Total Bill Impact (750 kWh)		$(0.001)	$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)		$(0.002)	$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.

6.0 CONCLUSION

NRLP's Application balances the needs of its system and assets and allows it to operate and maintain these assets in accordance with reliability standards and to satisfy regulatory, environmental, and legal requirements.

NRLP operates under unique circumstances when considering its corporate structure, asset holdings, and operating and management arrangements. Over the five-year term, this Application, will help ensure that NRLP's assets are managed effectively to benefit electricity customers across Ontario.

RATE BASE

1.0 INTRODUCTION

This exhibit outlines NRLP's rate base for the test years of 2025-2029, provides a description of each rate base component, and includes a comparison between the OEB approved 2020 rate base and historical actual figures.

The rate base underlying the revenue requirement for the test year includes a forecast of net utility plant, calculated on a mid-year average basis. No working capital has been requested, as discussed in section 4 below.

2.0 COMPARISON OF OEB APPROVED VS. ACTUAL RATE BASE

Table 1 below compares actual 2020 amounts to the 2020 rate base approved by the OEB in NRLP's 2020 revenue requirement application (EB-2018-0275).

Table 1 - 2020 OEB-approved versus 2020 Historic Year Rate Base ($M)

Rate Base Component	2020 Actual	2020 OEB-approved	Variance
Mid-Year Gross Plant	119.4	119.4	(0.0)
Less: Mid-Year Accumulated Depreciation	(1.6)	(1.6)	0.0
Mid-Year Net Utility Plant	**117.8**	**117.8**	**(0.0)**
Cash Working Capital	0.0	0.0	0.0
Materials & Supply Inventory	0.0	0.0	0.0
Total Rate Base	**117.8**	**117.8**	**(0.0)**

Actual rate base in 2020 is in line with the OEB-approved rate base.

3.0 UTILITY RATE BASE FORECAST

NRLP's utility rate base calculations for the test years are filed at Exhibit C-01-01, Attachment 5.

NRLP's approved rate base for the 2020 historical year is compared to the 2025 test year in Table 2. NRLP's most recent historical year, the 2024 bridge year and the 2025 to 2029 forecast years are shown in Table 3. The mid-year gross plant balance reflects the forecast capital expenditure programs and in-service additions.

Table 2 - Transmission Rate Base ($M)

Description	2020 OEB-approved	Test 2025
Mid-Year Gross Plant	119.4	119.5
Mid-Year Accumulated Depreciation	(1.6)	(9.6)
Mid-Year Net Plant	**117.8**	**109.9**
Cash Working Capital	0.0	0.0
Materials and Supply Inventory	0.0	0.0
Transmission Rate Base	**117.8**	**109.9**
% Change		(6.7%)

Table 3 - Transmission Rate Base ($M)

Description	Actual	Bridge	Test				
	2023	2024	2025	2026	2027	2028	2029
Mid-Year Gross Plant	119.4	119.4	119.5	119.6	119.6	119.6	119.6
Mid-Year Accumulated Depreciation	(6.4)	(8.0)	(9.6)	(11.2)	(12.8)	(14.5)	(16.1)
Mid-Year Net Plant	**113.1**	**111.5**	**109.9**	**108.4**	**106.7**	**105.1**	**103.5**
Cash Working Capital	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Materials and Supply Inventory	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transmission Rate Base	**113.1**	**111.5**	**109.9**	**108.4**	**106.7**	**105.1**	**103.5**
Year over year % change		(1.4%)	(1.4%)	(1.4%)	(1.5%)	(1.5%)	(1.6%)

Table 4 provides historical and bridge year continuity of total fixed assets. Further details in gross plant are discussed in Exhibit B-01-03, Attachment 1, Sections 3.2 through 4.3, and the in-service forecast is outlined in Section 4 below.

Table 4 - Continuity of Fixed Assets Summary ($M)

Description	OEB-Approved	Historic Years				Bridge	Test
	2020	2020	2021	2022	2023	2024	2025
Opening Gross Asset Balance	119.4	119.4	119.4	119.4	119.4	119.4	119.4
In-Service Additions	0.0	0.0	0.0	0.0	0.0	0.0	0.2
Retirements	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Transfers / Other	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Closing Gross Asset Balance	**119.4**	**119.4**	**119.4**	**119.4**	**119.4**	**119.4**	**119.6**

Table 5 includes a continuity of 2025 to 2029 forecast in-service additions, as follows:

Table 5 - Continuity of Fixed Assets Summary ($M)

Description	Test				
	2025	2026	2027	2028	2029
Opening Gross Asset Balance	119.4	119.6	119.6	119.6	119.6
In-Service Additions	0.2	0.0	0.0	0.0	0.0
Retirements	0.0	0.0	0.0	0.0	0.0
Sales	0.0	0.0	0.0	0.0	0.0
Transfers / Other	0.0	0.0	0.0	0.0	0.0
Closing Gross Asset Balance	**119.6**	**119.6**	**119.6**	**119.6**	**119.6**

4.0 CASH WORKING CAPITAL

Consistent with the prior approved transmission rate application for 2020 to 2024 rates, NRLP's expenses and revenues are planned to be generally synchronized such that no working capital has been requested in this Application. Despite not having undertaken an independent assessment, NRLP believes that it continues to be appropriate to have approximately zero working capital requirement, analogous to that of B2M Limited Partnership (B2M LP).

5.0 IN-SERVICE ADDITIONS

In-service additions represent increases to rate base as a result of capital work being declared in-service and ready for use.

During the rate period, there is a planned system renewal capital expenditure of $150K to be in-serviced in 2025. Further details can be found in the TSP within Exhibit B-01-03, Attachment 1, Sections 4.2 and 4.3.

NRLP
Continuity of Property, Plant and Equipment - Accumulated Depreciation
Historical (2020-2023), Bridge (2024) & Test (2025-2029) Years
Year Ending December 31
Total - Gross Balances
($ Millions)

Line No.	Year	Opening Balance	Additions	Retirements	Sales	Transfers In/Out and Other	Closing Balance	Average
		(a)	(b)	(c)	(d)	(e)	(f)	(g)
Historic								
1	2020	0.8	1.6	0.0	0.0	0.0	2.4	1.6
2	2021	2.4	1.6	0.0	0.0	0.0	4.0	3.2
3	2022	4.0	1.6	0.0	0.0	0.0	5.6	4.8
4	2023	5.6	1.6	0.0	0.0	0.0	7.2	6.4
Bridge								
5	2024	7.2	1.6	0.0	0.0	0.0	8.8	8.0
Test								
6	2025	8.8	1.6	0.0	0.0	0.0	10.4	9.6
7	2026	10.4	1.6	0.0	0.0	0.0	12.0	11.2
8	2027	12.0	1.6	0.0	0.0	0.0	13.7	12.8
9	2028	13.7	1.6	0.0	0.0	0.0	15.3	14.5
10	2029	15.3	1.6	0.0	0.0	0.0	16.9	16.1

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	**2025**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -			$ -	$ -			$ -	$ -
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 80.0	$ 0.2		$ 80.2	$ 5.6	$ 1.1		$ 6.7	$ 73.5
47	1730	Overhead conductors and devices	$ 39.4			$ 39.4	$ 3.1	$ 0.6		$ 3.7	$ 35.7
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 119.4**	**$ 0.2**	**$ -**	**$ 119.6**	**$ 8.8**	**$ 1.6**	**$ -**	**$ 10.4**	**$ 109.2**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 119.4**	**$ 0.2**	**$ -**	**$ 119.6**	**$ 8.8**	**$ 1.6**	**$ -**	**$ 10.4**	**$ 109.2**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 1.6**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1.6

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
4. The additions in column (E) must not include construction work in progress (CWIP).
5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	**2025**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -			$ -	$ -			$ -	$ -
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 80.0	$ 0.2		$ 80.2	$ 5.6	$ 1.1		$ 6.7	$ 73.5
47	1730	Overhead conductors and devices	$ 39.4			$ 39.4	$ 3.1	$ 0.6		$ 3.7	$ 35.7
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 119.4**	**$ 0.2**	**$ -**	**$ 119.6**	**$ 8.8**	**$ 1.6**	**$ -**	**$ 10.4**	**$ 109.2**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 119.4**	**$ 0.2**	**$ -**	**$ 119.6**	**$ 8.8**	**$ 1.6**	**$ -**	**$ 10.4**	**$ 109.2**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 1.6**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1.6

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2026

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -			$ -	$ -			$ -	$ -
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 80.2			$ 80.2	$ 6.7	$ 1.1		$ 7.8	$ 72.4
47	1730	Overhead conductors and devices	$ 39.4			$ 39.4	$ 3.7	$ 0.6		$ 4.2	$ 35.2
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 10.4**	**$ 1.6**	**$ -**	**$ 12.0**	**$ 108**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 10.4**	**$ 1.6**	**$ -**	**$ 12.0**	**$ 107.5**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 1.6**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1.6

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard: USGAAP
Year: 2027

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -			$ -	$ -			$ -	$ -
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 80.2			$ 80.2	$ 7.8	$ 1.1		$ 8.9	$ 71.3
47	1730	Overhead conductors and devices	$ 39.4			$ 39.4	$ 4.2	$ 0.6		$ 4.8	$ 34.6
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 12.0**	**$ 1.6**	**$ -**	**$ 13.7**	**$ 105.9**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 12.0**	**$ 1.6**	**$ -**	**$ 13.7**	**$ 105.9**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						$ 1.6			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1.6

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
4. The additions in column (E) must not include construction work in progress (CWIP).
5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard	USGAAP
Year	**2028**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -			$ -	$ -			$ -	$ -
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 80.2			$ 80.2	$ 8.9	$ 1.1		$ 9.9	$ 70.2
47	1730	Overhead conductors and devices	$ 39.4			$ 39.4	$ 4.8	$ 0.6		$ 5.4	$ 34.0
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 13.7**	**$ 1.6**	**$ -**	**$ 15.3**	**$ 104.3**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 13.7**	**$ 1.6**	**$ -**	**$ 15.3**	**$ 104.3**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**$ 1.6**			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1.6

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.

2 The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).

3 The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.

4 The additions in column (E) must not include construction work in progress (CWIP).

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.

6 The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Accounting Standard USGAAP
Year 2029

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
12	1610	Intangibles	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
	1665	Fuel holders, producers and acc.	$ -			$ -	$ -			$ -	$ -
	1675	Generators	$ -			$ -	$ -			$ -	$ -
N/A	1615	Land	$ -			$ -	$ -			$ -	$ -
1	1620	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
N/A	1705	Land	$ -			$ -	$ -			$ -	$ -
14.1	1706	Land rights	$ -			$ -	$ -			$ -	$ -
1	1708	Buildings and fixtures	$ -			$ -	$ -			$ -	$ -
47	1715	Station equipment	$ -			$ -	$ -			$ -	$ -
47	1720	Towers and fixtures	$ 80.2			$ 80.2	$ 9.9	$ 1.1		$ 11.0	$ 69.2
47	1730	Overhead conductors and devices	$ 39.4			$ 39.4	$ 5.4	$ 0.6		$ 5.9	$ 33.5
47	1735	Underground conduit	$ -			$ -	$ -			$ -	$ -
47	1740	Underground conductors and devices	$ -			$ -	$ -			$ -	$ -
17	1745	Roads and trails	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
	1925	Computer software	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ -			$ -	$ -			$ -	$ -
8	1935	Stores Equipment	$ -			$ -	$ -			$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -			$ -	$ -
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue5	$ -			$ -	$ -				$ -
										$ -	$ -
		Sub-Total	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 15.3**	**$ 1.6**	**$ -**	**$ 16.9**	**$ 102.6**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E	**$ 119.6**	**$ -**	**$ -**	**$ 119.6**	**$ 15.3**	**$ 1.6**	**$ -**	**$ 16.9**	**$ 102.6**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						$ 1.6			

10		Transportation
8		Stores Equipment

Less: *Fully Allocated Depreciation*	
Transportation	
Stores Equipment	
Net Depreciation	$ 1.6

Notes:

1. Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts.
2. The "CCA Class" for fixed assets should agree with the CCA Class used for tax purposes in Tax Returns. Fixed Assets sub-components may be used where the underlying asset components are classified under multiple CCA Classes for tax purposes. If an applicant uses any different classes from those shown in the table, an explanation should be provided. (also see note 3).
3. The table may need to be customized for a utility's asset categories or for any new asset accounts announced or authorized by the Board.
4. The additions in column (E) must not include construction work in progress (CWIP).
5. Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues.
6. The applicant must ensure that all asset disposals have been clearly identified in the Chapter 2 Appendices for all historic, bridge and test years. Where a distributor for general financial reporting purposes under IFRS has accounted for the amount of gain or loss on the retirement of assets in a pool of like assets as a charge or credit to income, for reporting and rate application filings, the distributor shall reclassify such gains and losses as depreciation expense, and disclose the amount separately.

NRLP
Statement of Average Rate Base
Bridge Year (2024) and Test Years (2025-2029)
Year Ending December 31
($ Millions)

Line No.	Particulars	2024	2025	2026	2027	2028	2029
	Electric Utility Plant						
1	**Gross plant**						
	Transmission Corridor Land and Rights	0.0	0.0	0.0	0.0	0.0	0.0
	Towers and Fixtures	80.0	80.2	80.2	80.2	80.2	80.2
	Conductors and Devices	39.4	39.4	39.4	39.4	39.4	39.4
	Roads and Trails	0.0	0.0	0.0	0.0	0.0	0.0
	Total Gross Plant	119.4	119.6	119.6	119.6	119.6	119.6
2	Accumulated Depreciation	8.8	10.4	12.0	13.7	15.3	16.9
3	Net plant in-service	110.7	109.2	107.5	105.9	104.3	102.6
4	Average net plant for rate base	111.5	109.9	108.4	106.7	105.1	103.5
5	Construction work in progress	0.0	0.0	0.0	0.0	0.0	0.0
6	Average net utility plant	$ 111.5	109.9	108.4	106.7	105.1	103.5
	Working Capital						
7	Cash working capital	0.0	0.0	0.0	0.0	0.0	0.0
8	Materials and Supplies Inventory	0.0	0.0	0.0	0.0	0.0	0.0
9	Total working capital	0.0	0.0	0.0	0.0	0.0	0.0
10	Total rate base	$ 111.5	109.9	108.4	106.7	105.1	103.5

REVENUE REQUIREMENT

1.0 SUMMARY OF REVENUE REQUIREMENT

NRLP follows standard regulatory practice and has calculated its revenue requirement as follows:

Table 1 - Revenue Requirement ($M)

Components	2025	2026	2027	2028	2029	Reference
OM&A	1.1	1.1	1.0	1.1	1.9	Exhibit F-01-01
Depreciation	1.6	1.6	1.6	1.6	1.6	Exhibit F-05-01
Income Taxes	0.1	0.1	0.1	0.1	0.1	Exhibit F-06-01, Attachment 1
Return on Capital	6.2	6.2	6.1	6.0	5.9	Exhibit G-01-01
Total Revenue Requirement	**9.0**	**8.9**	**8.8**	**8.8**	**9.5**	
Deduct External Revenues and Other[1]	(0.6)	0.0	0.0	0.0	0.0	Exhibit H-01-01
Rates Revenue Requirement	**8.4**	**8.9**	**8.8**	**8.8**	**9.5**	Exhibit E-01-01, Attachment 1

The above rates revenue requirement is the amount required by NRLP to achieve its business objectives, responsible stewardship of a safe and reliable system, and impact on rates. The above rates revenue requirement is also a reflection of NRLP's commitment to operating at the lowest practical cost. An excel version of the 2025 to 2029 revenue requirements has been provided at Attachment 1 of Exhibit E-01-01.

2.0 CALCULATION OF REVENUE REQUIREMENT

The details of the revenue requirement components are as follows:

[1] This comprises of the disposition of Earnings Sharing Mechanism (ESM) regulatory account

1 **Table 2 - OM&A Expense ($M)***

	2025	2026	2027	2028	2029
Service Level Agreement Costs	0.5	0.6	0.5	0.6	1.4
Incremental Expenses	0.6	0.5	0.5	0.5	0.5
Total OM&A	**1.1**	**1.1**	**1.0**	**1.1**	**1.9**

* Exhibit F-02-01

Table 3 - Depreciation and Amortization Expense ($M)*

	2025	2026	2027	2028	2029
Depreciation	1.6	1.6	1.6	1.6	1.6
Total Depreciation Expense	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**

* Exhibit F-05-01

Table 4 - Corporate Income Taxes ($M)*

	2025	2026	2027	2028	2029
Regulatory Taxable Income (after loss Carryforward)	0.0	0.0	0.0	0.0	0.0
Income Tax Rate	26.5%	26.5%	26.5%	26.5%	26.5%
Corporate Income Tax *(Does not apply if less than zero)*	**0.0**	**0.0**	**0.0**	**0.0**	**0.0**
Accounting Income	2.3	2.3	2.2	2.2	2.2
OCMT Rate	2.7%	2.7%	2.7%	2.7%	2.7%
Net Income Taxes (OCMT)	**0.1**	**0.1**	**0.1**	**0.1**	**0.1**

* Exhibit F-06-01

Table 5 - Return on Capital ($M)*

	2025	2026	2027	2028	2029
Return on Debt	2.2	2.2	2.2	2.1	2.1
Return on Equity	4.1	4.0	3.9	3.9	3.8
Return on Capital	**6.2**	**6.2**	**6.1**	**6.0**	**5.9**

* Exhibit G-01-01

3.0 REVENUE REQUIREMENT – YEAR OVER YEAR COMPARISON

The following comparisons in the revenue requirement between the 2025 test year, the 2024 bridge year and the last OEB-approved year (2020) are provided below.

3.1 2025 TEST YEAR COMPARED TO 2024 OEB APPROVED

The change in the total revenue requirement of $0.4M (5.0%) from 2024 approved revenue requirement to the 2025 revenue requirement is predominantly driven by higher OM&A, as well as cost of debt, given the maturity of NRLP's previous five-year long-term debt ($20.3 million).

Table 6 - Comparison of 2025 to 2024 OEB-approved

Description	2024 ($M)	2025 ($M)	2025 vs. 2024 ($M)	2025 vs. 2024 (%)
Total Revenue Requirement	8.6	8.9	0.4	5.0%

4.0 2025 TEST YEAR VS 2020 OEB-APPROVED

The difference in the 2025 revenue requirement compared to the 2020 OEB-approved test year is predominantly driven by higher cost of OM&A and debt given the maturity of NRLP's previous five-year long-term debt ($20.3 million), as further explained in Exhibit F-02-01 and Exhibit G-01-01, respectively.

Table 7 - Impact of the Individual Component on Total Revenue Requirement

Description	2020 ($M)	2025 ($M)	2025 vs. 2020 ($M)	2025 vs. 2020 (%)
OM&A	0.8	1.1	0.2	27%
Rate Base	5.6	5.7	0.1	1%
Cost of debt	1.7	2.2	0.5	29%
Tax	0.1	0.1	0.0	1%
Impact on Total Revenue Requirement	**8.2**	**9.0**	**0.8**	**10%**

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

Line No.	Particulars		Test 2025	Test 2026	Test 2027	Test 2028	Test 2029
			(a)	(b)	(c)	(d)	(e)
	Cost of Service						
1	Operating, maintenance & administrative	$	1.1	1.1	1.0	1.1	1.9
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	$	2.8	2.8	2.7	2.8	3.6
5	Return on capital		6.2	6.2	6.1	6.0	5.9
6	Total revenue requirement	$	9.0	8.9	8.8	8.8	9.5

OPERATING COSTS SUMMARY

1.0 INTRODUCTION

This Exhibit presents an overview of NRLP's operating costs and includes the following elements, for which the overall costs are shown in Table 1 below:

- Operation, Maintenance and Administrative (OM&A),
- Depreciation and Amortization, and
- Income Taxes.

Table 1 - Operating Costs ($M)

Description	Historical Years				Bridge Year	Forecast				
	2020	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
OM&A	0.7	0.5	0.6	1.1	1.3	1.1	1.1	1.0	1.1	1.9
Depreciation and Amortization	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Income Taxes	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total Operating Costs	**2.4**	**2.2**	**2.3**	**2.7**	**2.9**	**2.8**	**2.8**	**2.7**	**2.8**	**3.6**

The annual average proposed operating costs for the 2025 – 2029 is forecast to be $2.9M, an $0.5M increase compared to 2020 – 2024. The increase in OM&A expenses is primarily due to higher vegetation management maintenance needs in 2029, as well higher advisory committee costs and shared asset allocation. This increase is partially offset by the lower depreciation, as documented in Exhibit F-02-01 and Exhibit F-05-01, respectively.

2.0 KEY ELEMENTS OF OPERATING COSTS

NRLP's operating costs forecast has been developed to sustain the safe and reliable operation of its transmission assets.

2.1 OPERATION, MAINTENANCE AND ADMINISTRATIVE (OM&A)

NRLP is managed by its general partner, Hydro One Indigenous Partnerships GP Inc. (HOIP GP), which retains Hydro One Networks (HONI), under a Service Level Agreement, to plan and organize the operation and maintenance of the assets and provide certain corporate and administrative support as outlined in Exhibit F-03-01.

OM&A expenses are derived from various work programs and functions performed by or on behalf of the Partnership. Further details on the OM&A costs are provided in Exhibit F-02-01.

2.2 DEPRECIATION AND AMORTIZATION

The depreciation expense for NRLP in this Application is supported by a depreciation study completed by Alliance Consulting Group which leverages the service life parameters approved for HONI Transmission in support of Hydro One's 2023 to 2027 Custom IR application (EB-2021-0110) while adjusting for NRLP’s depreciation reserves to calculate NRLP’s depreciation rate and depreciation expense. Further details are provided in Exhibit F-05-01.

2.3 INCOME TAXES

Under the *Income Tax Act*, a partnership is not taxable but is required to compute its taxable income, which is then allocated to its partners. Details of the calculation of the Income Tax expense are shown in Exhibit F-06-01.

DEPRECIATION EXPENSES

1.0 INTRODUCTION

The purpose of this exhibit is to summarize the method and amount of NRLP's depreciation and amortization expense for the 2025 to 2029 forecast years.

2.0 DEPRECIATION METHODOLOGY

The depreciation and amortization expense included in NRLP's application transmission revenue requirement for the 2020 to 2024 period (EB-2018-0275) was supported by an independent depreciation study conducted by Foster Associates Inc. (Foster) for HONI's 2020-2022 Transmission Revenue Requirement application (EB-2019-0082). The OEB accepted the Foster depreciation study for the purposes of determining NRLP's depreciation rates and depreciation expense for the 2020 to 2024 rate period.

For its 2023 to 2027 Custom IR application (EB-2021-0110), HONI engaged Alliance Consulting Group (Alliance) to perform a new depreciation study covering HONI's transmission, distribution and common assets as the basis for HONI's Transmission and Distribution depreciation and amortization expenses from 2023 to 2027. The OEB approved those expenses and the basis for their calculation. For a summary of the changes in the depreciation methodology between the Foster depreciation study and the Alliance depreciation study approved in HONI's 2023 to 2027 Custom IR rebasing application, please refer to Exhibit E-08-01 of EB-2021-0110.[1]

Consistent with the approach taken in its 2020-2024 revenue requirement application in EB-2018-0275, NRLP adopted HONI's transmission depreciation rates when this Application was originally filed. NRLP sought to confirm this approach with Alliance and engaged Alliance to perform a depreciation study, which leveraged the service life parameters from HONI's Alliance depreciation study. As a single asset transmission utility, NRLP's assets are similar in nature to HONI's transmission assets and are

[1] EB-2021-0110, Exhibit E-08-01, section 1.3; and Exhibit E-08-01, Attachment 1

expected to perform in the same manner as assets on which HONI's depreciation study was based. The plant account service life parameters from HONI transmission assets were then adjusted for NRLP's depreciation reserves to form NRLP's updated depreciation rate and depreciation expense for the 2025 to 2029 period. See Exhibit F, Tab 5, Schedule 1, Attachment 3.

3.0 DEPRECIATION EXPENSE

As discussed above, NRLP's depreciation study was used to determine the depreciation expense for the test years. Historical and forecast depreciation expense from 2020 to 2029 are summarized in Table 1.

Table 1 - NRLP Depreciation and Amortization Expenses ($M)

Description	Historical				Bridge	Test				
	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Depreciation On Fixed Assets	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6	1.6
Less Capitalized Depreciation	-	-	-	-	-	-	-	-	-	-
Asset Removal Costs	-	-	-	-	-	-	-	-	-	-
Losses/(Gains) On Asset Disposition	-	-	-	-	-	-	-	-	-	-
Total	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**	**1.6**

Detailed depreciation schedules are filed at Exhibit F-05-01, Attachments 1 and 2.

Depreciation and Amortization Expenses

NRLP
Depreciation & Amortization Expenses
2020-2023 Historical, 2024 Bridge, 2025 Test
Year Ending December 31
($ Millions)

Line No.	Particulars	2020 Deprn Rate	2020 Provision ($M)	2021 Deprn Rate	2021 Provision ($M)	2022 Deprn Rate	2022 Provision ($M)	2023 Deprn Rate	2023 Provision ($M)	2024 Deprn Rate	2024 Provision ($M)	2025 Deprn Rate	2025 Provision ($M)
		(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)
	Depreciation Expenses												
1	Major Fixed Assets												
2	Towers and Fixtures	1.28%	1.0242	1.28%	1.0242	1.28%	1.0242	1.28%	1.0242	1.28%	1.0242	1.34%	1.0732
3	Overhead Lines	1.44%	0.5675	1.44%	0.5675	1.44%	0.5675	1.44%	0.5675	1.44%	0.5675	1.43%	0.5636
3	Depreciation on Fixed Assets	**1.34%**	1.5917	**1.34%**	1.5917	**1.34%**	1.5917	**1.34%**	1.5917	**1.34%**	1.5917	**1.37%**	1.6367
4	Less Capitalized Depreciation		-		-		-		-		-		-
5	Asset Removal Costs		-		-		-		-		-		-
6	Total Depreciation Expenses		1.59		1.59		1.59		1.59		1.59		1.64
	Amortization Expenses												
7	Other Amortization		-		-		-		-		-		-
8	Total Amortization Expenses		-		-		-		-		-		-
9	Total Depreciation & Amortization Expenses		1.59		1.59		1.59		1.59		1.59		1.64
10	Depreciation & Amortization for recovery		1.59		1.59		1.59		1.59		1.59		1.64

Depreciation and Amortization Expenses

NRLP
Depreciation & Amortization Expenses
2025 - 2029 Test Year
Year Ending December 31
($ Millions)

Line No.	Particulars	2025 Deprn Rate	2025 Provision ($M)	2026 Deprn Rate	2026 Provision ($M)	2027 Deprn Rate	2027 Provision ($M)	2028 Deprn Rate	2028 Provision ($M)	2029 Deprn Rate	2029 Provision ($M)
		(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)	(a)	(b)
	Depreciation Expenses										
1	Major Fixed Assets										
2	Towers and Fixtures	1.34%	1.07	1.34%	1.07	1.34%	1.07	1.34%	1.07	1.34%	1.07
3	Overhead Lines	1.43%	0.56	1.43%	0.56	1.43%	0.56	1.43%	0.56	1.43%	0.56
4	Depreciation on Fixed Assets	**1.37%**	1.64	**1.37%**	1.64	**1.37%**	1.64	**1.37%**	1.64	**1.37%**	1.64
5	Less Capitalized Depreciation		-		-		-		-		-
6	Asset Removal Costs		-		-		-		-		-
7	Total Depreciation Expenses		1.64		1.64		1.64		1.64		1.64
	Amortization Expenses										
8	Other Amortization		-		-		-		-		-
9	Total Amortization Expenses		-		-		-		-		-
10	Total Depreciation & Amortization Expenses		1.64		1.64		1.64		1.64		1.64
11	Depreciation & Amortization for recovery		1.64		1.64		1.64		1.64		1.64

ALLIANCE CONSULTING GROUP

July 23, 2024

Mr. Jonathan Myers
Torys LLP
79 Wellington St. W. 30th Floor.
Box 270, TD South Tower
Toronto, Ontario, M5K 1N2, Canada

Re: Proposed Depreciation Rates Niagara Reinforcement Limited Partnership

Jonathan:

Alliance Consulting Group is pleased to present our findings on the depreciation rates for Niagara Reinforcement Limited Partnership (NRLP).

The scope of our depreciation study process included:

- Collection of plant and reserve data
- Reconciliation of assembled database to Company records
- Discussion with NRLP plant accounting and operations personnel regarding asset characteristics
- Evaluate asset characteristics and dispersion patterns in relation to approved lives for Hydro One Networks
- Analysis of recorded plant amounts and depreciation reserves, and
- Development of recommended depreciation rates for each category of plant account.

After review and discussions, we confirmed that the life parameters currently in use from the 2019 Depreciation Study for Hydro One Networks, Inc. (Hydro One) are representative of the assets in NRLP.

In the case of NRLP as with Hydro One, no net salvage is included in the accrual rate computations. Proposed annual depreciation expense amounts for all accounts were calculated by the straight-line, remaining life procedure used by Hydro One in its Joint Rate Application (EB-2021-0110).

To compute the proposed annual accrual rate, various computations are necessary. Attachment 1 shows the currently approved Hydro One parameters which are the recommended depreciation parameters that underlie the proposed rate computations. Attachment 2 shows the development of the composite remaining life for each plant account. Those computations are determined by the formula shown below.

$$\text{Composite Remaining Life} = \frac{\sum \text{Original Cost x Vintage Remaining Life}}{\sum \text{Original Cost}}$$

The next step in computing the proposed depreciation accrual rates was to determine the proposed annual accrual by taking the difference between the surviving investment, and the allocated book depreciation reserve divided by the composite remaining life to yield the annual depreciation expense. That computation is shown in the formula below.

$$\text{Proposed Annual Depreciation Expense} = \frac{\text{Original Cost – Book Reserve}}{\text{Composite Remaining Life}}$$

The final step to compute the proposed depreciation accrual rates was to divide the proposed annual depreciation expense by the original cost of the asset. That is shown in Attachment 3 and the formula below.

$$\text{Proposed Annual Depreciation Rate} = \frac{\text{Proposed Annual Depreciation Expense}}{\text{Original Cost}}$$

The proposed rates are based on NRLP plant and accumulated depreciation investment computed at December 31, 2023 using the same straight line, broad-group, remaining life depreciation system used in the Hydro One depreciation study. A comparison of these rates is shown in the table below.

Account	Description	Current Rate	Proposed Rate
1720	Towers and Fixtures	1.24%	1.34%
1730	Overhead Conductors and Devices	1.30%	1.43%

The last attachment (Attachment 4) shows an expense comparison between the current and proposed depreciation rates.

We wish to express our appreciation for this opportunity to be of service to NRLP and for the assistance provided to us. We would be pleased to discuss our results and review with you or others at your convenience.

Very truly yours,

Dane A. Watson

Dane A. Watson – Engagement Partner – Alliance Consulting Group

Attachment 1 - Depreciation Parameters used for Current and Proposed Depreciation Accrual Rates

Attachment 2 - Computation of Proposed Composite Remaining Life by Account

Attachment 3 - Computation of Proposed Depreciation Accrual Rate by Account

Attachment 4 - Comparison of Current and Proposed Accrual Rates and Proposed Depreciation Expense

Attachment 1

Niagara Reinforcement LP (NRLP)

Comparison of Current and Proposed Depreciation Parameters
AS OF DECEMBER 31, 2023

		Hydro One Current		NRLP Proposed	
Account	Description	Life	Curve	Life	Curve
1720	Towers and Fixtures	75	R3	75	R3
1730	Overhead Conductors and Devi	70	R4	70	R4

Attachment 2

Niagara Reinforcement LP (NRLP)
Computation of Proposed Composite Remaining Life
AS OF DECEMBER 31, 2023

Account	Vintage Year	Age	Plant Amount	Proposed Average Service Life	Proposed Vintage Remaining Life	Plant x Vintage Remaining Life	Proposed Composite Remaining Life
1720	2019	4.5	80,013,202.50	75.00	70.58	5,647,631,881.96	
1720 Total			80,013,202.50			5,647,631,881.96	70.58
1730	2019	4.5	39,409,487.80	70.00	65.51	2,581,540,173.56	
1730 Total			39,409,487.80			2,581,540,173.56	65.51
Grand Total			119,422,690.30			8,229,172,055.52	

Attachment 3

Niagara Reinforcement LP (NRLP)
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
AS OF DECEMBER 31, 2023

Account	Description	Plant Balance Total at 12/31/2023	Book Reserve 12/31/2023	Unaccrued Balance	Proposed Composite Remaining Life	Proposed Annual Accrual	Proposed Annual Accrual Rate
1720	Towers and Fixtures	80,013,202.50	4,604,759.76	75,408,442.74	70.58	1,068,354.16	1.34%
1730	Overhead Conductors and Devices	39,409,487.80	2,553,734.78	36,855,753.02	65.51	562,635.58	1.43%
		119,422,690.30	7,158,494.54	112,264,195.76		1,630,989.74	

Niagara Reinforcement LP (NRLP)
Comparison of Current and Proposed Depreciation Rates and Expense
AS OF DECEMBER 31, 2023

Account	Description	Plant Balance Total at 12/31/2023	Hydro One Current Rates: Annual Accrual Rate	Hydro One Current Rates: Annual Accrual	Proposed: Annual Accrual Rate	Proposed: Annual Accrual	Difference Annual Accrual
1720	Towers and Fixtures	80,013,202.50	1.24%	992,163.71	1.34%	1,068,354.16	76,190.45
1730	Overhead Conductors and Devices	39,409,487.80	1.30%	512,323.34	1.43%	562,635.58	50,312.24
		119,422,690.30		1,504,487.05		1,630,989.74	126,502.68

NRLP

Calculation of Utility Income Taxes
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

SUMMARY OF TAX EXPENSE

	2024	2025	2026	2027	2028	2029
Hydro One Networks Inc.	0.06	0.06	0.06	0.06	0.06	0.06
Hydro One Indigenous Partnerships GP Inc	0.00	0.00	0.00	0.00	0.00	0.00
11100726 Canada Limited (Six Nations)	0.00	0.00	0.00	0.00	0.00	0.00
Mississaugas of the New Credit First Nation Toronto Purchase Trust	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**

NRLP

Line No.	Particulars	2024 (a)	2025 (b)	2026 (c)	2027 (d)	2028 (e)	2029 (f)
	Determination of Taxable Income						
1	Regulatory Net Income (before tax)	3.86	4.11	4.05	3.99	3.93	3.87
2	Book to Tax Adjustments:						
3	Depreciation and amortization	1.59	1.64	1.64	1.64	1.64	1.64
4	Capital Cost Allowance	-6.51	-5.99	-5.51	-5.07	-4.67	-4.30
5	Other	0.00	0.00	0.00	0.00	0.00	0.00
6	Total Adjustments	-4.92	-4.36	-3.88	-3.44	-3.03	-2.66
7	**Regulatory Taxable Income/(Loss) before Loss Carry Forward**	**$ -1.06**	**$ -0.24**	**$ 0.18**	**$ 0.56**	**$ 0.90**	**$ 1.21**
	Allocation of Taxable Income						
8	Hydro One Networks Inc.	-0.56	-0.11	0.12	0.33	0.52	0.69
9	Hydro One Indigenous Partnerships GP Inc	0.00	0.00	0.00	0.00	0.00	0.00
10	11100726 Canada Limited (Six Nations)	-0.28	-0.08	0.03	0.12	0.21	0.29
11	Mississaugas of the New Credit First Nation Toronto Purchase Trust	-0.22	-0.06	0.02	0.10	0.17	0.23
12	Total	$ -1.06	$ -0.24	$ 0.18	$ 0.56	$ 0.90	$ 1.21
	Tax Rates						
12	Federal Tax	15.00 %	15.00 %	15.00 %	15.00 %	15.00 %	15.00 %
13	Provincial Tax	11.50 %	11.50 %	11.50 %	11.50 %	11.50 %	11.50 %
14	Total Tax Rate	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %

NRLP

Calculation of Utility Income Taxes
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

SUMMARY OF TAX EXPENSE

	2024	2025	2026	2027	2028	2029
Hydro One Networks Inc.	0.06	0.06	0.06	0.06	0.06	0.06
Hydro One Indigenous Partnerships GP Inc	0.00	0.00	0.00	0.00	0.00	0.00
11100726 Canada Limited (Six Nations)	0.00	0.00	0.00	0.00	0.00	0.00
Mississaugas of the New Credit First Nation Toronto Purchase Trust	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**

Hydro One Networks Inc.

Line No.	Particulars	2024 (a)	2025 (a)	2026 (b)	2027 (c)	2028 (d)	2029 (e)
	Determination of Income Taxes						
1	Allocation of Taxable Income from NRLP	-0.56	-0.11	0.12	0.33	0.52	0.69
2	Taxable Capital Gains from NRLP	0.00	0.00	0.00	0.00	0.45	1.01 *
3	Taxable Income	-0.56	-0.11	0.12	0.33	0.97	1.70
4	Loss Carryforward	0.56	0.11	-0.12	-0.33	-0.97	-1.70
5	Taxable Income after loss carryforward	0.00	0.00	0.00	0.00	0.00	0.00
6	Tax Rate	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %
7	**Income Tax Expense**	$ **0.00**	$ **0.00**	$ **0.00**	$ **0.00**	$ **0.00**	$ **0.00**

*The capital gains inclusion is 50% based on currently enacted legislation and does not reflect the proposed increase to the capital gains of 2/3 as proposed in the 2024 Federal Budget

Line No.	Particulars	2024	2025	2026	2027	2028	2029
	Loss Continuity Schedule						
6	Opening Losses Carryforward	-6.70	-7.26	-7.36	-7.24	-6.91	-5.94
7	Losses (Incurred)/Utilized during the year	-0.56	-0.11	0.12	0.33	0.97	1.70
8	Closing Losses Carryforward	-7.26	-7.36	-7.24	-6.91	-5.94	-4.24
	Determination of Corporate Minimum Tax						
9	Allocation of Accounting Income from NRLP	2.14	2.29	2.25	2.22	2.18	2.15
10	Corporate Minimum Tax Rate	2.70 %	2.70 %	2.70 %	2.70 %	2.70 %	2.70 %
11	Corporate Minimum Tax Potentially Applicable	0.06	0.06	0.06	0.06	0.06	0.06
12	Ontario Income Tax	0.00	0.00	0.00	0.00	0.00	0.00
13	**Corporate Minimum Tax Payable (Utilized)**	$ **0.06**	$ **0.06**	$ **0.06**	$ **0.06**	$ **0.06**	$ **0.06**
14	Opening CMT Credit Carryforward	0.30	0.36	0.42	0.48	0.54	0.60
15	CMT Credit Incurred/(utilized)	0.06	0.06	0.06	0.06	0.06	0.06
16	Closing CMT Credit Carryforward	0.36	0.42	0.48	0.54	0.60	0.66
17	**Total Taxes Expense for Hydro One Networks Inc.**	$ **0.06**	$ **0.06**	$ **0.06**	$ **0.06**	$ **0.06**	$ **0.06**

NRLP

Calculation of Utility Income Taxes
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

SUMMARY OF TAX EXPENSE

	2024	2025	2026	2027	2028	2029
Hydro One Networks Inc.	0.06	0.06	0.06	0.06	0.06	0.06
Hydro One Indigenous Partnerships GP Inc	0.00	0.00	0.00	0.00	0.00	0.00
11100726 Canada Limited (Six Nations)	0.00	0.00	0.00	0.00	0.00	0.00
Mississaugas of the New Credit First Nation Toronto Purchase Trust	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**

Hydro One Indigenous Partnerships GP Inc

Line No.	Particulars	2024	2025	2026	2027	2028	2029
		(a)	(a)	(b)	(c)	(d)	(e)
	Determination of Income Taxes						
1	Allocation of Taxable Income from NRLP	0.00	0.00	0.00	0.00	0.00	0.00
2	Loss Carryforward	0.00	0.00	0.00	0.00	0.00	0.00
3	Taxable Income after loss carryforward	0.00	0.00	0.00	0.00	0.00	0.00
4	Tax Rate	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %	26.50 %
5	Sub Total	0.00	0.00	0.00	0.00	0.00	0.00
6	Additional Taxes due to Negative ACB	0.00	0.00	0.00	0.00	0.00	0.00
7	**Income Tax Expense**	**$ 0.00**	**$ 0.00**	**0.00**	**0.00**	**0.00**	**0.00**
	Loss Continuity Schedule						
8	Opening Losses Carryforward	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
9	Losses (Incurred)/Utilized during the year	0.00	0.00	0.00	0.00	0.00	0.00
10	Closing Losses Carryforward	-0.01	-0.01	-0.01	-0.01	-0.01	-0.01
	Determination of Corporate Minimum Tax						
11	Allocation of Accounting Income from NRLP	0.00	0.00	0.00	0.00	0.00	0.00
12	Corporate Minimum Tax Rate	2.70 %	2.70 %	2.70 %	2.70 %	2.70 %	2.70 %
13	Corporate Minimum Tax Potentially Applicable	0.00	0.00	0.00	0.00	0.00	0.00
14	Ontario Income Tax	0.00	0.00	0.00	0.00	0.00	0.00
15	**Corporate Minimum Tax Payable (Utilized)**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**
16	Opening CMT Credit Carryforward	0.00	0.00	0.00	0.00	0.00	0.00
17	CMT Credit Incurred/(utilized)	0.00	0.00	0.00	0.00	0.00	0.00
18	Closing CMT Credit Carryforward	0.00	0.00	0.00	0.00	0.00	0.00
19	**Total Taxes Expense for Hydro One Indigenous Partnerships GP Inc**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**

NRLP

Calculation of Utility Income Taxes
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

SUMMARY OF TAX EXPENSE

	2024	2025	2026	2027	2028	2029
Hydro One Networks Inc.	0.06	0.06	0.06	0.06	0.06	0.06
Hydro One Indigenous Partnerships GP Inc	0.00	0.00	0.00	0.00	0.00	0.00
11100726 Canada Limited (Six Nations)	0.00	0.00	0.00	0.00	0.00	0.00
Mississaugas of the New Credit First Nation Toronto Purchase Trust	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**

11100726 Canada Limited (Six Nations)

Line No.	Particulars	2024 (a)	2025 (a)	2026 (b)	2027 (c)	2028 (d)	2029 (e)
	Determination of Income Taxes						
1	Allocation of Taxable Income from NRLP	-0.28	-0.08	0.03	0.12	0.21	0.29
2	Tax Rate	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %
3	**Income Tax Expense**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**
	Determination of Corporate Minimum Tax						
4	Allocation of Accounting Income from NRLP	0.95	1.01	1.00	0.98	0.97	0.95
5	Corporate Minimum Tax Rate	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %
6	**Corporate Minimum Tax Payable**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**
7	**Total Taxes Expense for 11100726 Canada Limited (Six Nations)**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**

NRLP

Calculation of Utility Income Taxes
Bridge (2024) and Test Years (2025 to 2029)
Year Ending December 31
($ Millions)

SUMMARY OF TAX EXPENSE

	2024	2025	2026	2027	2028	2029
Hydro One Networks Inc.	0.06	0.06	0.06	0.06	0.06	0.06
Hydro One Indigenous Partnerships GP Inc	0.00	0.00	0.00	0.00	0.00	0.00
11100726 Canada Limited (Six Nations)	0.00	0.00	0.00	0.00	0.00	0.00
Mississaugas of the New Credit First Nation Toronto Purchase Trust	0.00	0.00	0.00	0.00	0.00	0.00
Total	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**	**0.06**

Mississaugas of the New Credit First Nation Toronto Purchase Trust

Line No.	Particulars	2024 (a)	2025 (a)	2026 (b)	2027 (c)	2028 (d)	2029 (e)
	Determination of Income Taxes						
1	Allocation of Taxable Income from NRLP	-0.22	-0.06	0.02	0.10	0.17	0.23
2	Tax Rate	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %
3	**Income Tax Expense**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**
	Determination of Corporate Minimum Tax						
4	Allocation of Accounting Income from NRLP	0.76	0.02	0.02	0.02	0.02	0.02
5	Corporate Minimum Tax Rate	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %	0.00 %
6	**Corporate Minimum Tax Payable**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**
7	**Total Taxes Expense for Mississaugas of the New Credit First Nation Toronto Purchase Trus**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**	**$ 0.00**

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	4.348%	25-Feb-35	20.3	0.1	20.2	99.50	4.41%	0.0	19.8	17.0	0.8	
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	3.06%

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	4.348%	25-Feb-35	19.8	0.1	19.7	99.50	4.41%	19.8	18.9	19.4	0.9	
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	2.0	3.18%

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

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%	3.06%	1.9
2	Short-term debt	4.4	4.0%	6.23%	0.3
3	Deemed long-term debt	(0.7)	(0.7%)	3.06%	(0.0)
4	Total debt	66.0	60.0%	3.28%	2.2
5	Common equity	44.0	40.0%	9.21%	4.0
6	Total rate base	109.9	100.0%	5.65%	6.2

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 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 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)

		2026			
Line No.	Particulars	($M)	%	Cost Rate (%)	Return ($M)
		(a)	(b)	(c)	(d)
I	Long-term debt	61.5	56.8%	3.18%	2.0
2	Short-term debt	4.3	4.0%	6.23%	0.3
3	Deemed long-term debt	(0.8)	(0.8%)	3.18%	(0.0)
4	Total debt	65.0	60.0%	3.38%	2.2
5	Common equity	43.3	40.0%	9.21%	4.0
6	Total rate base	108.4	100.0%	5.71%	6.2

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 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 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%	3.18%	1.9
2	Short-term debt	4.3	4.0%	6.23%	0.3
3	Deemed long-term debt	(0.8)	(0.8%)	3.18%	(0.0)
4	Total debt	64.0	60.0%	3.38%	2.2
5	Common equity	42.7	40.0%	9.21%	3.9
6	Total rate base	106.7	100.0%	5.71%	6.1

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 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 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%	3.18%	1.9
2	Short-term debt	4.2	4.0%	6.23%	0.3
3	Deemed long-term debt	(0.8)	(0.8%)	3.18%	(0.0)
4	Total debt	63.1	60.0%	3.38%	2.1
5	Common equity	42.0	40.0%	9.21%	3.9
6	Total rate base	105.1	100.0%	5.71%	6.0

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 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 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)

Line No.	Particulars	2029 ($M)	%	Cost Rate (%)	Return ($M)
		(a)	(b)	(c)	(d)
I	Long-term debt	58.8	56.8%	3.18%	1.9
2	Short-term debt	4.1	4.0%	6.23%	0.3
3	Deemed long-term debt	(0.8)	(0.8%)	3.18%	(0.0)
4	Total debt	62.1	60.0%	3.38%	2.1
5	Common equity	41.4	40.0%	9.21%	3.8
6	Total rate base	103.5	100.0%	5.71%	5.9

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 2024 Cost of Capital Parameters
Common Equity % based on OEB's 2024 Cost of Capital Parameters
Total rate base from C-01-01

REGULATORY ACCOUNTS

1.0 INTRODUCTION

The purpose of this exhibit is to provide a description of NRLP's regulatory accounts and proposal with respect to account requests and disposition. The regulatory accounts reported by NRLP have been established consistent with the OEB's requirements as set out in the Accounting Procedures Handbook, subsequent OEB direction, or as per specific requests initiated by NRLP.

NRLP's regulatory balances were last disposed on a final basis in EB-2020-0251 as of December 31, 2020.[1]

In this Application, NRLP requests disposition of its regulatory account balance in the Earnings Sharing Mechanism (ESM) deferral account that accumulated between 2021 and 2023, as summarized in Table 1:

Table 1 - Summary of Regulatory Account Balances ($)

Description	Principal Balance as at Dec. 31, 2023	Projected Interest up to Dec. 31, 2024	Total Balance
Tax Rate and Rule Changes Variance Account	0	0	0
Niagara Reinforcement Limited Partnership Deferral Account	0	0	0
ESM Deferral Account	(535,761)	(50,288)	(586,049)
Total Group 2 Balances	**(535,761)**	**(50,288)**	**(586,049)**

The projected interest for 2024 is calculated by applying interest on the December 31, 2023 principal balance using the OEB's quarterly prescribed interest rates for deferral and variance accounts. As shown in the DVA Continuity Schedule at Exhibit H-01-01,

[1] EB-2020-0251, 2021 Uniform Transmission Rates, Decision and Rate Order, December 17, 2020

Attachment 1, there is a small principal adjustment of $55K in 2023 to reflect minimum corporate taxes that were included in the 2022 Regulated ROE calculation but not included in the 2022 ESM calculation. Although recorded in the account in 2023, the adjustment was reflected in the 2022 audited financial statements as filed in Exhibit A-06-02, Attachment 2. In addition, there was a similar adjustment of $34K in 2024 to reflect minimum corporate taxes that were included in the 2023 Regulated ROE calculation but not the 2023 ESM calculation.

Information on each account and its balance is described in Section 2.0 of this Exhibit, with a detailed continuity schedule for the period 2020 to the present, showing separate itemization of opening balances, annual adjustments, transactions, interest and closing balances presented in Exhibit H-01-01, Attachment 1. No adjustments have been made to account balances that were previously approved by the OEB on a final basis.

NRLP is requesting to dispose of the ESM deferral account balance as part of its revenue requirement over a one-year period commencing January 1, 2025.

2.0 DESCRIPTION OF REGULATORY ACCOUNTS

The OEB approved the establishment of three regulatory accounts for NRLP which are described herein.

2.1 NIAGARA REINFORCEMENT LIMITED PARTNERSHIP DEFERRAL ACCOUNT (NRLPDA)

On September 26, 2019, Hydro One received approval for the establishment of the NRLPDA to record the revenue requirement for the Niagara Reinforcement Project that was placed in-service on August 30, 2019. NRLP was approved to record the interim revenue requirement effective September 1, 2019 until the OEB-approved effective date of the revenue requirement in the rebasing application.[2]

[2] NRLP is requesting that revenue from UTRs begins as of January 1, 2020. In that event, the NRLPDA would cease recording of revenue requirement as of December 31, 2019.

On December 19, 2019, the OEB approved NRLP's request to expand the scope of the NRLPDA to include forgone revenue, where the OEB ruled that any potential forgone revenue resulting from the difference between interim and final revenue requirement would be disposed no later than its 2021 rates application.[3] As part of the OEB's April 9, 2020 Decision and Order on NRLP's 2020-2024 revenue requirement, the OEB ordered that the previously established NRLPDA be used to track 2020 forgone revenue and established that the NRLPDA will not close until the 2020 forgone revenue is cleared.[4]

In the OEB's 2020 Uniform Transmission Rates (UTR) decision on NRLP's forgone revenue, the OEB decided that NRLP may continue to use its already established NRLPDA to track forgone revenue until all forgone revenue associated with the difference between revenue earned under interim UTRs and the revenues that would have been received under the approved UTRs, based on the OEB-approved 2020 rates revenue requirement and load forecasts, has been collected through the UTRs.[5]

In this Application, NRLP requests the continuance of the NRLPDA over the 2025 to 2029 rate term in the event the OEB's decision on the application may not be available by January 1, 2025. As such, NRLP proposes to use the NRLPDA to record any differences between the interim revenue requirement awarded (as at the effective date) and the actual revenue included in the final decision (as at the implementation date). Any balance will be interest improved and submitted for disposition at NRLP's next rate application.

[3] EB-2018-0275, NRLP, Decision and Order on Interim Revenue Requirement, December 19, 2019
[4] EB-2018-0275, NRLP, Decision and Order, April 9, 2020, p. 8; and EB-2020-0180, 2020 Uniform Transmission Rates, revised July 31, 2020, pp. 15-16
[5] EB-2020-0180, 2020 Uniform Transmission Rates, revised July 31, 2020, p.16

2.2 TAX RATE AND RULE CHANGES VARIANCE ACCOUNT (ACCOUNT 1592)

Effective January 1, 2020, NRLP was approved a new tax rate and rule changes variance account in the EB-2018-0275 proceeding. This account was approved to track the revenue requirement impact of legislative or regulatory changes to tax rates or rules compared to costs approved by the OEB as part of 2020 to 2024 transmission rates, and differences that result from a change in, or a disclosure of, a new assessment or administrative policy that is published in the public tax administration or interpretation bulletins by relevant federal or provincial tax authorities.

NRLP proposes continuance of this account in order to track any potential revenue requirement impact of any legislative or regulatory changes to tax rates or rules during the 2025 to 2029 rate term.

2.3 EARNINGS SHARING MECHANISM (ESM) DEFERRAL ACCOUNT

Effective January 1, 2020, NRLP was approved for an ESM deferral account in EB-2018-0275 to record any material over-earnings realized during any year of the five-year term that is 100 basis points above deemed return on equity.

The use of an ESM provides protection for ratepayers if forecasts differ from actual results over the five-year period. The 100 basis points is consistent with the OEB-approved materiality threshold for Hydro One Transmission. The ratepayer share of the excess earnings is adjusted for any tax impacts and is credited to the deferral account which is now brought forward for disposition in this Application.

NRLP proposes continuance of this account over the 2025 to 2029 rate term and will share with customers 50% of any earnings that exceed the regulatory return on equity reflected in this Application by more than 100 basis points in any year of the five-year term.

3.0 ACCOUNTS SOUGHT FOR DISPOSITION

3.1 ESM DEFERRAL ACCOUNT (ACCOUNT 2435)

As at January 1, 2025, NRLP is requesting approval to dispose the balance of the ESM deferral account as of December 31, 2023. The calculation of the ROE uses actual rate base as determined by the sum of the Average regulated fixed assets and working capital allowance, as set out in the "Calculation of ROE on a Deemed Basis" filed pursuant to the OEB's RRR reporting.[6] The ROE calculation is normalized for revenue impacting items such as entries recorded in the year which relate to prior years to normalize the in-year net income. The ratepayers' share of the excess earnings are grossed up for the associated tax impact to the extent that there are no losses in the year. As shown in Table 2 below, the 2022 and 2023 ESM amounts do not require a tax-gross up because NRLP was in a taxable loss position.

Table 2 - 2020-2023 ESM Calculations

		2020	2021	2022	2023
Rate base[A]	**A**	$117,835,025	$116,243,360	$114,651,694	$113,060,029
Capital Structure[B]:					
Long-term debt	**B**	56%	56%	56%	56%
Short-term debt	**C**	4%	4%	4%	4%
Common equity	**D**	40%	40%	40%	40%
Allowed Return[C]:					
Long-term debt	**E**	3.05%	2.34%	2.34%	2.34%
Short-term debt	**F**	2.75%	2.75%	2.75%	2.75%
Allowed ROE	**G**	8.52%	8.52%	8.52%	8.52%
Regulated Net Income (actual) [D]	**H**	$4,317,312	$4,641,768	$4,812,637	$4,673,197
Achieved ROE	**I = H / (A x D)**	9.16%	9.98%	10.49%	10.33%
Allowed ROE	**J**	8.52%	8.52%	8.52%	8.52%
Over/(Under) earning (%)	**K = I - J**	0.64%	1.46%	1.974%	1.81%
OEB allowed earnings	**L**	1%	1%	1%	1%

[6] RRR 2.1.5.6 ROE Filing Guide

threshold[E]					
Over/(Under) earning (%)	**M = K - L**	-0.36%	0.46%	0.974%	0.81%
Excess Earnings Pool	**N = A x D x M**		$214,429	$446,701	$367,871
Sharing with ratepayers	**O**		50%	50%	50%
Sharing with ratepayers	**P = N x O**		$107,215	$223,350 [7]	$183,935
Tax Grossed-Up Principal Amount	**Q = P / (0.735 – P) x 0.55 + P**		$128,475		
Total Cumulative ESM Principal Balance (as of Dec. 31, 2023)					**$535,760[8]**

[A] Average rate base for 2021 and 2022 as per 2022 ROE filing
[B] Capital structure rates from filing EB-2018-0275
[C] Allowed return from filing EB-2018-0275, long-term debt rate updated as per EB-2020-0225
[D] Regulated Net Income as per 2020 to 2023 ROE filing
[E] ESM sharing deadband as established in ESM Deferral Account Accounting Order in EB-2018-0275

4.0 ACCOUNTS NOT SOUGHT FOR DISPOSITION

4.1 TAX RATE AND RULE CHANGES VARIANCE ACCOUNT (ACCOUNT 1592)

As at December 31, 2023, NRLP had a $nil balance in this account as its tax rates were in alignment with current tax legislation.

4.2 NIAGARA REINFORCEMENT LIMITED PARTNERSHIP DEFERRAL ACCOUNT (NRLPDA)

As at December 31, 2023, NRLP had a $nil balance in this account as the 2020 forgone revenues and accrued interest amounts were approved to be disposed as part of the 2021 UTR rates proceeding (EB-2020-0251).

5.0 ACCOUNTING AND CONTROL PROCESS

The accounts noted above will continue to be managed in a consistent manner. When applicable, they will be updated monthly and interest applied to the monthly opening

[7] DVA Continuity at Exhibit H-01-01, Attachment 1, cell Z10 (2022 transactions) and cell AL10 (2023 principal adjustment)
[8] $34K variance is a result of an adjustment made to the principal balance for 2023 in 2024. The adjustment is a result of corporate taxes which were included in the 2023 ROE calculation but not included in the 2023 ESM calculation.

principal balance in this account according to the OEB-approved rate. Balances will be reported to the OEB as part of the quarterly reporting process, and will be consistent with last audited financial statements. The outstanding balances as of December 31, 2023, are being submitted for approval as part of this NRLP rate application, as applicable.

A certification on the account balances pursuant to the Chapter 1 Filing Requirements has been provided at Exhibit A-01-02, Attachment 2.

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		2020									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-20	Transactions Debit / (Credit) during 2020	Board-Approved Disposition during 2020	Principal Adjustments during 2021	Closing Principal Balances as of Dec 31-20	Opening Interest Amounts as of Jan-1-20	Interest Jan-1 to Dec-31-20	Interest Disposition during 2020- instructed by Board	Interest Adjustments during 2021	Closing Interest Balance as at Dec 31 -20 balance
Group 2 Accounts											
Foregone Revenue Deferral Account	1508				4,148,691	4,148,691				66,635	66,635
Tax Rate and Rule Changes Variance Account	1592										-
Earnings Sharing Mechanism (ESM) Deferral Account	2435										-
Total Regulatory Accounts Seeking Disposition – Group 2					**4,148,691**		**-**		**-**	**66,635**	**66,635**
Total Regulatory Accounts Not Seeking Disposition – Group 2							**-**		**-**	**66,635**	**66,635**

		2021									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-21	Transactions Debit / (Credit) during 2021	Board-Approved Disposition during 2021	Principal Adjustments during 2022	Closing Principal Balances as of Dec 31-21	Opening Interest Amounts as of Jan-1-21	Interest Jan-1 to Dec-31-21	Interest Disposition during 2021- instructed by Board	Interest Adjustments during 2022	Closing Interest Balance as at Dec 31 -21 balance
Group 2 Accounts											
Foregone Revenue Deferral Account	1508	4,148,691		4,148,691		(0)	66,635	12,550	79,217		(33)
Tax Rate and Rule Changes Variance Account	1592					-					-
Earnings Sharing Mechanism (ESM) Deferral Account	2435	-	(128,475)			(128,475)	-				-
Total Regulatory Accounts Seeking Disposition – Group 2		**4,148,691**	**-**	**4,148,691**		**(0)**	**66,635**		**79,217**	**12,550**	**(33)**
Total Regulatory Accounts Not Seeking Disposition – Group 2		**4,148,691**	**-**	**4,148,691**		**(0)**	**66,635**		**79,217**	**12,550**	**(33)**

		2022									
Account Descriptions	Account Number	Opening Principal Amounts as of Jan-1-22	Transactions Debit / (Credit) during 2022	Board-Approved Disposition during 2022	Principal Adjustments during 2023	Closing Principal Balances as of Dec 31-22	Opening Interest Amounts as of Jan-1-22	Interest Jan-1 to Dec-31-22	Interest Disposition during 2022- instructed by Board	Interest Adjustments during 2023	Closing Interest Balance as at Dec 31 -22 balance
Group 2 Accounts											
Foregone Revenue Deferral Account	1508	(0)				(0)	(33)	33			-
Tax Rate and Rule Changes Variance Account	1592	-				-					-
Earnings Sharing Mechanism (ESM) Deferral Account	2435	(128,475)	(278,736)		55,386	(351,826)	0	(2,473)			(2,473)
Total Regulatory Accounts Seeking Disposition – Group 2		**(128,475)**	**(278,736)**	**-**		**(351,826)**	**(33)**	**(2,440)**	**-**	**-**	**(2,473)**
Total Regulatory Accounts Not Seeking Disposition – Group 2		**(128,475)**	**(278,736)**	**-**		**(351,826)**	**(33)**	**(2,440)**	**-**	**-**	**(2,473)**

Account Descriptions	Account Number	2023 Opening Principal Amounts as of Jan-1-23	Transactions Debit / (Credit) during 2023	Board-Approved Disposition during 2023	Principal Adjustments during 2024	Closing Principal Balances as of Dec 31-23	Opening Interest Amounts as of Jan-1-23	Interest Jan-1 to Dec-31-23	Interest Disposition during 2023- instructed by Board	Interest Adjustments during 2024	Interest Balance as at Dec 31 -23 balance
Group 2 Accounts											
Foregone Revenue Deferral Account	1508	(0)				(0)	-	(0)			(0)
Tax Rate and Rule Changes Variance Account	1592					-					-
Earnings Sharing Mechanism (ESM) Deferral Account	2435	(351,826)	(218,174)		34,239	(535,761)	(2,473)	(18,402)			(20,875)
Total Regulatory Accounts Seeking Disposition – Group 2		**(351,826)**	**(218,174)**	**-**	**34,239**	**(535,761)**	**(2,473)**	**(18,402)**	**-**	**-**	**(20,875)**
Total Regulatory Accounts Not Seeking Disposition – Group 2		**(351,826)**	**(218,174)**	**-**	**34,239**	**(535,761)**	**(2,473)**	**(18,402)**	**-**	**-**	**(20,875)**

		2024							2.1.7 RRR		
Account Descriptions	Account Number	Principal Disposition during 2024 - instructed by OEB	Interest Disposition during 2024 - instructed by OEB	Closing Principal Balances as of Dec 31-23 Adjusted for Dispositions during 2024	Closing Interest Balances as of Dec 31-23 Adjusted for Dispositions during 2024	Projected Interest from Jan 1, 2024 to December 31, 2024 on Dec 31 -23 balance adjusted for disposition during 2024	Total Interest	Total Claim	Accounts To Dispose Yes/No	As of Dec 31-23	Variance RRR vs. 2023 Balance (Principal + Interest)
Group 2 Accounts											
Foregone Revenue Deferral Account	1508			(0)	(0)	(0)	(0)	(0)	No		
Tax Rate and Rule Changes Variance Account	1592					-	-	-	No		
Earnings Sharing Mechanism (ESM) Deferral Account	2435			(535,761)	(20,875)	(29,413)	(50,288)	(586,049)	Yes	(556,635.72)	0.00
Total Regulatory Accounts Seeking Disposition – Group 2				**(535,761)**	**(20,875)**	**(29,413)**	**(50,288)**				
Total Regulatory Accounts Not Seeking Disposition – Group 2				**(535,761)**	**(20,875)**	**(29,413)**	**(50,288)**	**(586,049)**			

COST ALLOCATION AND RATE DESIGN

1.0 COST ALLOCATION

All assets associated with NRLP are classified as Network assets, consistent with the cost allocation methodology approved by the OEB for NRLP in proceeding EB-2018-0275. A listing of the NRLP assets by functional category is provided below in Table 1. Accordingly, the total rates revenue requirement associated with NRLP's transmission assets will be allocated to the Network pool.

Table 1 - NRLP Assets by Functional Category

Circuit	Section	From	To	Functional Category
Q26M	4	Allanburg West JCT	Middleport TS	Network
Q35M	4	Allanburg West JCT	St.Anns JCT	Network
Q35M	5	St.Anns JCT	Caledonia Q35M JCT	Network
Q35M	6	Caledonia Q35M JCT	Middleport TS	Network

The NRLP Network rates revenue requirement[1] for the purpose of setting uniform transmission rates (UTRs) effective for test year 2025 is $8.40M, for 2026 is $8.94 M, for 2027 is 8.82M, for 2028 is 8.81M and for 2029 is $9.49M, as determined per Exhibit E-01-01.

2.0 CHARGE DETERMINANTS

There are no customer delivery points supplied directly from the NRLP assets, and as such the NRLP Network charge determinant for the purpose of setting Uniform Transmission Rates is zero.

[1] Including the disposition of the ESM balance as part of its revenue requirement over a one-year period commencing January 1, 2025.

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OVERVIEW OF UNIFORM TRANSMISSION RATES

1.0 INTRODUCTION

Transmission rates in Ontario have been established on a uniform basis for all transmitters in Ontario since April 30, 2002, as per the OEB's Decision in RP-2001-0034/RP20010035/RP-2001-0036/RP-1999-0044. The current Uniform Transmission Rate (UTR) Schedule, which were effective on January 1, 2024, as part of the OEB's Decision and Rate Order in EB-2023-0222 issued on January 18, 2024, are filed as Exhibit I-03-01, Attachment 1. Exhibit I-03-01, Attachment 2 shows the revenue requirement and charge determinant details used to derive the currently approved 2024 UTRs.

Since rates are established on a uniform basis, NRLP's requested rates revenue requirement is a contributor to the total revenue requirement to be collected from the provincial UTR. The rates revenue requirement for all the other transmitters in the province approved to participate in the UTR must be added to that of NRLP in order to calculate the total transmission rates revenue requirement to be collected via the UTR.[1]

The total rates 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 for NRLP will be allocated to the Network rate pool, as discussed in Exhibit I-01-01. The rates revenue requirements by rate pool for the other transmitters are allocated to either the Network rate pool, or in proportion to Hydro One Transmission's rates revenue requirement across the three rate pools.

[1] The other seven transmitters currently included in the UTRs are Hydro One Networks Inc. (Hydro One), Hydro One Networks Sault Ste. Marie LP (HOSSM), Five Nations Energy Inc. (FNEI), Canadian Niagara Power Inc. (CNPI), Wataynikaneyap Power LP (WPLP), Upper Canada Transmission 2, Inc., operating as East-West Tie Limited Partnership (EWTLP), and B2M Limited Partnership (B2M LP).

Once the total rates revenue requirement by rate pool has been established, rates are determined by applying the Provincial charge determinants for each rate pool to the total revenue for each rate pool. The Provincial charge determinants are the sum of all charge determinants, by rate pool, approved by the OEB for each of the transmitters participating in the UTR.

The 2025 UTR schedule is provided in Exhibit I-04-01, Attachment 1, and the rates revenue requirement and charge determinants details used to calculate the 2025 UTRs are provided in Exhibit I-04-01, Attachment 2. The 2025 UTR calculation includes the 2025 NRLP rates revenue requirement and the currently approved values for the other transmitters.[2]

2.0 BILL IMPACTS

The impact of transmission rates on a customer's total bill varies between transmission-connected and distribution-connected customers. Table 1 shows the estimated average transmission cost as a percentage of the total bill for a transmission-connected customer.

Table 1 - Estimated Transmission Cost as a Percentage of Total Electricity Market Costs

Figure	Cost Component	¢/kWh	Source
A	Commodity	10.43	IESO Monthly Market Report December 2023
B	Wholesale Market Service Charges	0.48	IESO Monthly Market Report December 2023
C	Wholesale Transmission Charges	1.51	IESO Monthly Market Report December 2023
D	**Total Monthly Cost for TX-Connected Customers**	**12.42**	**D=A+B+C**
E	Transmission as % of Total Cost for TX-Connected Customers	12.2%	E=C/D

[2] See EB-2023-0222, Decision and Order on 2024 Uniform Transmission Rates, page 4, Table 1

The NRLP 2025 rates revenue requirement represents approximately 0.4% of the total rates revenue requirement across all transmitters, which is approximated by adjusting the 2024 overall approved UTR revenue requirement to include the NRLP 2025 rates revenue requirement.[3] This percentage has been applied to NRLP's changes in revenue requirement to calculate the net impact on average transmission rates for each year in the test period, from 2025 to 2029. Figure E (12.2%) from Table 1 above has been applied to the net impact on average transmission rates to estimate the bill impact on transmission-connected customers in the test period, as shown in Table 2.

Table 2 - Average Bill Impacts on Transmission-Connected Customers

	2024	2025	2026	2027	2028	2029
NRLP's Rates Revenue Requirement [1][2]	$8,565,165	$8,404,946	$8,941,505	$8,821,716	$8,805,767	$9,491,689
% Change in Rates Revenue Requirement over prior year		-1.9%	6.4%	-1.3%	-0.2%	7.8%
% Impact of load forecast change		0.0%	0.0%	0.0%	0.0%	0.0%
Net Impact on Average Transmission Rates [3]		**-0.007%**	**0.024%**	**-0.005%**	**-0.001%**	**0.030%**
Transmission as a % of Tx-connected customer's Total Bill		12.2%	12.2%	12.2%	12.2%	12.2%
Estimated Average Transmission Customer Bill Impact [4]		**-0.001%**	**0.003%**	**-0.001%**	**0.000%**	**0.004%**

[1] 2024 rates revenue requirement per Decision and Rate Order, EB-2023-0128, Decision and Order, September 7, 2023.

[2] 2025-2029 rates revenue requirement per Exhibit E-01-01.

[3] The calculation of net impact on transmission rates accounts NRLP's 2024 rates revenue requirement as 0.4% of the total rates revenue requirement across all transmitters (i.e. 0.4% x -1.9% = -0.007% in 2025) per Decision and Rate Order, EB-2023-0222, 2024 Uniform Transmission Rates Updater-Schedule A, January 18, 2024.

[4] The calculation of estimated average transmission customer bill impact is the net impact on average transmission rates on the transmission portion of a transmission connected customer's total bill (i.e. -0.007% x 12.2% = -0.001% in 2025).

The annual total bill impacts for a typical medium density residential (Hydro One-Dx R1) customer consuming 750 kWh monthly and a typical General Service Energy less than 50 kW (Hydro One-Dx GS<50kW) customer consuming 2,000 kWh monthly are determined based on the forecast change in the customer's Retail Transmission Service Rates (RTSRs) during the test period, as detailed in Table 3.

[3] Exhibit I-04-01, Attachment 1

1 **Table 3 - Bill Impacts for Typical Distribution-Connected Customers**

	Calculation [1]	2024	2025	2026	2027	2028	2029
NRLP's Rates Revenue Requirement ($M)[2]	A	8.565	8.405	8.942	8.822	8.806	9.492
NRLP's 2024 Rates Revenue Requirement as % of UTR Network Revenue Requirement[3]	B	0.624%					
Estimated Net Impact on RTSR-Network[4]	$C=(A/A_{PY}-1)*B_{2024}$		-0.012%	0.040%	-0.008%	-0.001%	0.049%
Typical Medium Density (HONI-Dx R1) Customer Consuming 750 kWh per Month							
		2024	**2025**	**2026**	**2027**	**2028**	**2029**
RTSR Network Charge ($)[5],[6]	$D=D_{PY}*(1+C)$	9.523	9.521	9.525	9.524	9.524	9.529
RTSR Connection Charge ($)[5],[7],[8]	E	7.021	7.021	7.021	7.021	7.021	7.021
Total RTSR Charge ($)	F=D+E	16.544	16.542	16.546	16.545	16.545	16.550
Estimated Change in RTSR Network Charge ($)[8]	$G=C*D_{PY}$		(0.001)	0.004	(0.001)	(0.000)	0.005
Total Bill ($)[8]	$H=H_{PY}+D$	141.102	141.101	141.105	141.104	141.104	141.109
Increase as a % of Total bill	$I=G/H_{PY}$		-0.001%	0.003%	-0.001%	0.000%	0.003%
Typical General Service Energy less than 50 kW (GS<50kW Customer Consuming 2,000 kWh per Month							
		2024	**2025**	**2026**	**2027**	**2028**	**2029**
RTSR Network Charge ($) [5],[6]	$J=J_{PY}*(1+ C)$	20.386	20.383	20.391	20.390	20.389	20.399
RTSR Connection Charge ($) [5],[7],[8]	K	16.221	16.221	16.221	16.221	16.221	16.221
Total RTSR Charge ($)	L=J+K	36.606	36.604	36.612	36.610	36.610	36.620
Estimated Change in RTSR Network Charge ($) [8]	$M=C*J_{PY}$		(0.002)	0.008	(0.002)	(0.000)	0.010
Total Bill ($) [9]	$N=N_{PY}+M$	441.578	441.576	441.584	441.583	441.582	441.592
Increase as a % of Total bill	$O=M/N_{PY}$		-0.001%	0.002%	0.000%	0.000%	0.002%

[1] Inputs are current year (CY) unless otherwise denoted (e.g. PY refers to the value from the previous year). Calculations are for test period, from 2025-2029.
[2] NRLP's 2024 rates revenue requirement per Decision and Rate Order, EB-2023-0128, Decision and Order, September 7, 2023, and the 2025-2029 rates revenue requirement as per Exhibit E-01-01.
[3]Represents NRLP's currently approved revenue disbursement allocator based on the approved Total 2024 UTR Network Revenue Requirement of $1,373,508,207 as per OEB Decision and Rate Order, EB-2023-0222, 2024 Uniform Transmission Rates Update-Schedule A, January 18, 2024.
[4] The calculation of net impact on HONI-Dx's RTSR Network is NRLP's change in rates revenue requirement relative to its share of the total 2024 UTR Network revenue requirement.
[5] HONI-Dx's currently approved RTSRs are based on the Preliminary 2024 UTRs, EB-2023-0222, September 28, 2023.
[6] Represents the approved 2024 RTSR Network ($/kWh) effective January 1, 2024 approved per the OEB Decision and Rate Order, EB-2023-0030, December 14, 2023, multiplied by the monthly consumption (i.e. 750kWh/month HONI-Dx R1 or 2,000 kWh/month HONI-Dx GS<50kW), multiplied by the corresponding approved loss factor.
[7]Represents the approved 2024 RTSR Connection ($/kWh) effective January 1, 2024 approved per the OEB Decision and Rate Order, EB-2023-0030, December 14, 2023, multiplied by the monthly consumption (i.e. 750kWh/month HONI-Dx R1 or 2,000 kWh/month HONI-Dx GS<50kW), multiplied by the corresponding approved loss factor.
[8]NRLP's rates revenue requirement is wholly allocated to the Network rate pool. As a result, NRLP's rates revenue requirement impacts RTSR-N, and not RTSR-C.
[9]2024 Total bill including HST, based on time-of-use commodity price effective November 1, 2023 and distribution rates effective January 1, 2024 approved per Distribution Rate Order EB-2023-0030, dated December 14, 2023, with 19.3% Ontario Energy Rebate (effective November 1, 2023), $0.42 Smart Meter Entity Charge (effective January 1, 2023) and Distribution Rate Protection cap of $39.49 (effective July 1, 2023 for HONI-Dx R1). Total bills for the test period reflect the annual estimated change in RTSR-N and do not account for corresponding adjustments for HST and OER.

PROPOSED ONTARIO TRANSMISSION RATE SCHEDULES

The current 2024 UTR Schedules and the total revenue requirement and charge determinants for all transmitters are updated with NRLP's 2025 revenue requirement to establish the proposed 2025 UTR and revenue disbursement allocators which are included in the following attachments.

Attachment 1: Proposed 2025 Ontario Uniform Transmission Rate Schedules (Updated)

Attachment 2: Proposed 2025 Uniform Transmission Rates and Revenue Disbursement Allocators (Updated)

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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):	**5.78**
$ 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	$8,404,946	$0	$0	$8,404,946
All Transmitters	$1,373,347,988	$218,001,720	$621,916,870	$2,213,266,578

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)	**5.78**	**0.95**	**3.21**	
Hydro One Allocation Factor	**0.87877**	**0.97325**	**0.97325**	
HOSSM Allocation Factor	**0.01867**	**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	**0.00612**	**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 E-01-01.
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.