ROADMAP OF EVIDENCE ADDRESSING TRANSMISSION, HOSSM AND DISTRIBUTION OM&A COSTS

1.0 INTRODUCTION

Given the breadth of evidence supporting this application and the multiple witnesses supporting the various categories of Operations, Maintenance and Administration (OM&A) costs, this roadmap provides stakeholders with a reference point for navigating the OM&A evidence and associated witnesses.

2.0 TRANSMISSION OM&A EVIDENCE

Exhibit E-02-01 provides the Summary of Transmission OM&A Expenditures. It provides an overview of overall OM&A costs for the Transmission business, including the various categories of expenditures, and summarizes the OM&A envelope level variance explanations. The summary exhibit, in turn, refers to the underlying exhibits that provide further details on the OM&A categories. By way of example, details on Transmission Sustainment OM&A are contained in Exhibit E-02-02.

The following are the Transmission OM&A exhibits and associated witnesses:

Exhibit Reference	Exhibit Title	Witness
E-02-01	Summary of Transmission OM&A Expenditures	Anthony Nava, Donna Jablonsky, Mark Brodie
E-02-02	Transmission Sustainment OM&A	Donna Jablonsky
E-02-03	Transmission Development OM&A	Mark Brodie
E-02-04	Transmission Customer Care OM&A	Spencer Gill
E-02-05	Transmission O&M Work Execution Strategy	Scott Vicary

3.0 HOSSM TRANSMISSION OM&A EVIDENCE

Hydro One Sault Ste. Marie's (HOSSM) Transmission OM&A Expenditures are included in Exhibit E-02-06. That exhibit provides an overview of overall OM&A costs for the HOSSM business, summarizes the OM&A envelope level variance explanations, and includes categories of expenditures. Since Hydro One has operationally integrated

HOSSM, OM&A is planned and executed on the same basis as Hydro One Transmission. Therefore, this exhibit refers to the Hydro One Transmission exhibits that provide further details on the OM&A categories, the underlying programs, and their drivers that apply to HOSSM on the same basis.

The following are HOSSM's Transmission OM&A exhibits and associated witnesses:

Exhibit Reference	Exhibit Title	Witness
E-02-06	HOSSM OM&A	Anthony Nava, Donna Jablonsky

4.0 DISTRIBUTION OM&A EVIDENCE

Exhibit E-03-01 provides the Summary of Distribution OM&A Expenditures. It provides an overview of overall OM&A costs for the Distribution business, including the various categories of expenditures, and summarizes the OM&A envelope level variance explanations. The summary exhibit, in turn, refers to the underlying exhibits that provide further details on the OM&A categories. By way of example, details on Distribution Sustainment OM&A are contained in Exhibit E-03-02.

The following are the Distribution OM&A exhibits and associated witnesses:

Exhibit Reference	Exhibit Title	Witness
E-03-01	Summary of Distribution OM&A Expenditures	Anthony Nava, Paul Ankrett, Aimee Oabel, David Paish, Kevin Marcotte, Spencer Gill, Peter Faltaous
E-03-02	Distribution Sustainment OM&A	Paul Ankrett, Aimee Oabel, David Paish, Kevin Marcotte
E-03-03	Distribution Development OM&A	Peter Faltaous
E-03-04	Distribution Customer Care OM&A	Spencer Gill
E-03-05	Distribution O&M Work Execution Strategy	Gianni DiFilippo Aimee Oabel

5.0 COMMON OM&A EVIDENCE

The Common OM&A exhibits outline the expenditures that are shared between segments of Hydro One and subsequently allocated to Hydro One Transmission, Hydro One Distribution, and HOSSM. Those exhibits, including the allocation methodology, and their associated witnesses are as follows:

Exhibit Reference	Exhibit Title	Witness
E-04-01	Summary of Common and Other OM&A	Anthony Nava
E-04-02	Common Corporate Functions and Services (CCF&S) and Other OM&A	Anthony Nava
E-04-03	Common Corporate OM&A - Planning	Alexander Jackson
E-04-04	Common Corporate OM&A - Information Solutions	Kevin Marcotte
E-04-05	Operations OM&A	Lorraine Gray; Kevin Marcotte
E-04-06	Common Corporate Costs OM&A - Transmission Cost of Sales - External Work	Scott Vicary, Julie Ricketts Daniel
E-04-07	Common Corporate Costs OM&A - Distribution Cost of Sales - External Work	Gianni DiFilippo
E-04-08	Common Corporate Costs & Allocation Methodology	Anthony Nava
E-09-06	Property Taxes and Rights Payments	Julie Ricketts Daniel

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SUMMARY OF TRANSMISSION OM&A EXPENDITURES

1.0 INTRODUCTION

This Exhibit summarizes Hydro One Transmission's Operations, Maintenance and Administration (OM&A) expenditures over the 2023 to 2028 period. This includes the 2023 to 2026 historical period,[1] the 2027 bridge year, and the 2028 test year.[2]

The Transmission OM&A plan is comprised of five categories: (i) Sustainment, (ii) Development, (iii) Customer Care, (iv) Common and Other, and (v) Property Taxes and Rights Payments. This exhibit addresses the first three categories, Exhibit E-04-01 addresses Common and Other OM&A, and Exhibit E-09-06 addresses Property Taxes and Rights Payments.

During 2023 and 2024, Hydro One faced market cost pressures, increasing mandatory compliance requirements, and evolving security needs. In response, Hydro One prioritized critical reliability and compliance-related work, including vegetation management required to maintain NERC FAC-003 compliance, protection and automation maintenance activities associated with NERC and NPCC requirements, and increased security expenditures. These conditions required the company to make business decisions about where and when to spend the overall OM&A funding available for the five-year custom incentive ratemaking (IR) term.

To address the challenges experienced in the early years of the current rate period, Hydro One implemented additional productivity and cost control measures, including a company-wide cost optimization program, as discussed in SPF 1.4.3.2. Hydro One also reduced, deferred, or re-paced certain planned work, where doing so would not create unacceptable near-term reliability, compliance or customer service risk. These measures helped offset the higher spending required earlier in the rate period and reduced the resulting pressure

[1] Includes actual expenditures for 2023-2025 and forecast expenditures for 2026.
[2] 2029 to 2032 OM&A is established mechanistically, using an index-based approach, in accordance with the Custom IR framework described in Exhibits A-04-01 and A-04-02.

on cumulative OM&A expenditures over the five-year period. At the same time, Hydro One continued to maintain the operational, engineering and asset management capabilities required to support the capital investment plan and the ongoing needs of the transmission system (see TSP 2.8, Section 2.8.6). Where critical work could not be deferred or reprioritized, Hydro One elected to proceed with the work, resulting in approximately $120M of expenditures above the amounts funded in rates over the five-year period.

By 2028, Hydro One must transition from short-term reprioritization to a sustainable operating plan. Deferrals in vegetation management on the 115 kV network, power equipment maintenance, and other critical activities can no longer continue, given growing vegetation risks, rising maintenance backlogs, deteriorating asset condition and the need to meet mandatory reliability and compliance requirements. During 2023-2027, Hydro One deferred preventive maintenance on transformers, circuit breakers, and switches to manage funding constraints; these activities must now be restored, as they provide critical asset condition information used to identify deficiencies, prioritize corrective work, and inform replacement decisions. The operating plan must also support a larger capital program and respond to increasing load growth, electrification, and greater exposure to severe weather. The proposed 2028 OM&A expenditures reflect the funding required to restore sustainable maintenance levels, support the capital plan outlined in the TSP, strengthen system resilience, and maintain reliable and secure service for customers.

1.1 BACKGROUND FOR VARIANCE EXPLANATIONS

The variance analyses in this exhibit are intended to assist the OEB in assessing Hydro One's Transmission OM&A requirements in the context of the current rate period and the 2028 test year. The analyses compare 2023 actuals to the 2023 OEB-approved amount at the envelope level. Variance explanations at the category, project, or program level are based on the filed program-level evidence in EB-2021-0110, adjusted for inflation and the proportionate application of approved settlement reductions (referred to as 'planned expenditure levels' throughout this exhibit). These are notional values because the approved settlement reductions were applied only to the OM&A envelope-level funding for 2023 and not specifically allocated to categories, projects or programs.

Hydro One provides variance explanations relative to the 2023 to 2027 annual average, as this provides a more representative basis for assessing variances relative to the Company's historical OM&A cost base. As discussed in Section 1.0, Hydro One incurred higher costs in 2023 and 2024 to address demand-driven work, inflationary pressures and mandatory requirements. Through productivity initiatives, cost control measures, and the selective deferrals or re-pacing of certain planned activities, Hydro One subsequently reduced spending where prudent to address these incremental requirements. Recognizing how Hydro One manages OM&A over the full five-year term, the annual average therefore provides a more appropriate basis for assessing plan-over-plan variances.

1.2 TRANSMISSION OM&A FORECAST OVERVIEW

The Transmission OM&A forecast for the 2028 test year aligns with the investment needs and drivers identified in the Transmission System Plan (TSP Section 2.1) and the Business Plan (Exhibit A-03-01, Attachment 1). Hydro One's Transmission OM&A expenditures for the historical, bridge, and test years are provided in Table 1 below.

Table 1 - Summary of Recoverable Transmission OM&A Expenses ($M)[3]

		Historical				Bridge Year	Test Year
	2023	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
Transmission	**OEB Approved**	**Actual**	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Sustainment		241.1	237.1	224.5	231.4	229.7	305.9
Development		12.7	12.0	8.2	11.7	11.3	13.0
Customer Care		6.3	6.6	6.8	5.0	4.9	6.8
Common and Other OM&A [1]		175.1	162.4	148.7	178.7	187.3	219.1
Property Taxes and Rights Payments		72.4	68.8	73.5	77.8	79.2	89.7
Total	**433.7**	**507.7**	**487.0**	**461.7**	**504.6**	**512.5**	**634.5**

[1] This includes Common Corporate Functions & Services (CCF&S), Asset Management (planning) costs, Digital & Technology Solutions (DTS), Operations, and Cost of Sales for external work & Other OM&A.

[3] Rounded figures within tables may not sum precisely due to rounding.

Hydro One Transmission is proposing an OM&A forecast of $634.5M for the 2028 test year. This is an increase of $200.8M relative to the 2023 OEB-approved amount in EB-2021-0110, $126.8M relative to 2023 actual expenditures, and $139.7M relative to the 2023-2027 annual average expenditures.

To distinguish the effects of inflation from changes in underlying OM&A requirements, Table 2 isolates the impact of inflation by comparing the 2028 OM&A proposal to the 2023 OEB-approved OM&A amount escalated annually using the applicable I-X factors.[4]

Table 2 - Comparison of 2028 Test Year OM&A to I-X Escalated 2023 OEB-Approved OM&A ($M)

Transmission OM&A	Amount ($M)	%
2023 OEB-approved OM&A	433.7	
I-X escalation from 2023 to 2028	82.0	
2023 OEB-approved OM&A escalated to 2028 using I-X *[1]*	515.7	
2028 Test Year OM&A	634.5	
Variance to 2028 Test Year OM&A	+118.8	+23.0%

[1] OEB inflation is assumed to be 2.9% in both 2027 and 2028.

As shown in Table 2, this results in an I-X-escalated 2028 benchmark of $515.7M. Comparing the 2028 OM&A proposal to this benchmark provides context for assessing changes in underlying OM&A requirements, net of inflationary impacts over the period. The 2028 OM&A proposal of $634.5M is $118.8M, or 23.0%, above the I-X-escalated benchmark.

The comparison demonstrates that a significant portion of the 2028 funding requirement is attributable to inflationary pressure on the underlying OM&A cost base before considering changes in underlying work requirements. Hydro One's proposed 2028 Transmission OM&A of $634.5M reflects the inflation-adjusted cost base established

[4] Where ‘I’ is the applicable annual OEB Inflation Factor, and ‘X’ is the 0.15% productivity factor approved in EB-2021-0110.

through the current rate period, together with the incremental funding required to restore sustainable maintenance levels and address increasing system needs.

This concept is further illustrated in Figure 1, which provides additional context for understanding the increase between the 2023 OEB-approved OM&A amount and the 2028 OM&A proposal. The I-X escalated benchmark reflects the impact of inflationary adjustments over the current period, while the remaining increase above that benchmark reflects the funding required to support the transition from short-term reprioritization to a sustainable operating plan.

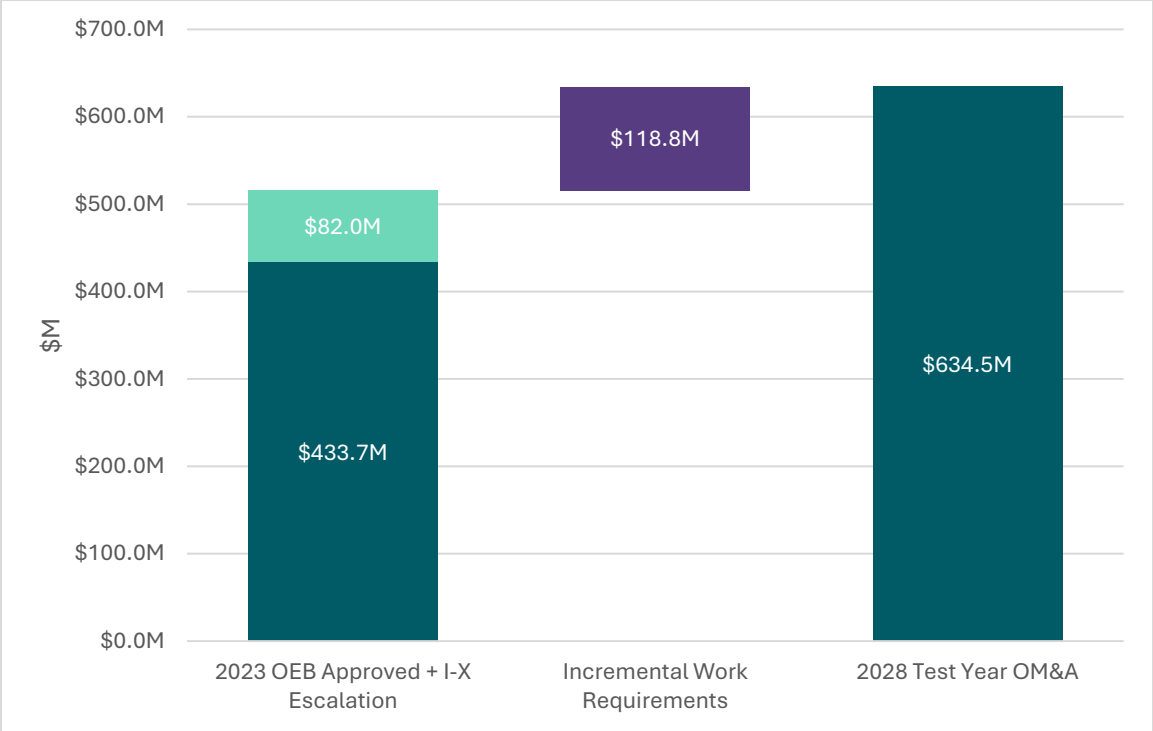


Figure 1: Increase Between the 2023 OEB-Approved OM&A Amount and the 2028 Test Year OM&A

2.0 DESCRIPTION OF OM&A CATEGORIES

Section 2.0 includes a brief description of each of the OM&A work categories. Further detail is provided in the accompanying exhibits identified in Table 3.

Table 3 - Supporting OM&A Exhibits

Cost Category	Exhibit Reference	Exhibit Title	Witness
Sustainment	E-02-02	Transmission Sustainment OM&A	Donna Jablonsky
Development	E-02-03	Transmission Development OM&A	Mark Brodie
Customer Care	E-02-04	Transmission Customer Care OM&A	Spencer Gill
Common and Other	E-04-01	Summary of Common and Other OM&A	Anthony Nava
Property Taxes and Rights Payments	E-09-06	Property Taxes and Rights Payments	Julie Ricketts Daniel

2.1 SUSTAINMENT

The Transmission Sustainment program is essential to maintaining the performance, reliability, and safety of Hydro One's transmission system. Through proactive inspection, preventive and corrective maintenance, vegetation management, and operational support activities, the program helps ensure that transmission assets continue to operate safely and as originally designed while supporting system reliability and service quality. The program also enables compliance with applicable regulatory, environmental, legal, and safety requirements. Work is divided into three categories:

i. Stations: supports the maintenance of existing transmission station equipment, including protection, control, and telecommunications assets;
ii. Lines: supports the maintenance of overhead transmission lines, underground cables, and vegetation management activities within transmission rights-of-way; and
iii. Engineering and environmental support: provides the specialized technical expertise and administrative support required to effectively manage transmission assets and inform asset management decisions.

As steward of a transmission system that includes 722 transformers, 4,691 circuit breakers, and associated equipment installed across 297 transmission stations, Hydro One continuously balances OM&A expenditures to maintain reliability, meet compliance obligations, and respond to evolving system needs. Over 2023-2025, the Transmission Sustainment program delivered a broad range of maintenance and compliance activities, including vegetation management on transmission rights-of-way to maintain NERC FAC-003 compliance, maintenance of transformers, circuit breakers, and other station equipment, and protection system maintenance in accordance with PRC-005 requirements. These activities help preserve asset condition, support system reliability, and meet mandatory compliance obligations.

2.2 DEVELOPMENT

The Transmission Development program establishes technical standards, advances new technologies, and addresses emerging system challenges to improve operational effectiveness, safety, and reliability. This work is critical to maintaining a high-performing transmission system, supporting innovation, and ensuring the reliable delivery of power to customers.

2.3 CUSTOMER CARE

The Transmission Customer Care program supports Hydro One's transmission-connected customers, including local distribution companies (LDCs), generators, and large end-users. Hydro One’s transmission system delivers electricity to more than 90% of Ontario customers, the majority of whom are served indirectly through local distribution networks. The program funds the activities, resources, tools, and dedicated account management required to serve over 260 transmission-connected customers. These functions facilitate customer connections, manage operational and connection agreements, address customer inquiries and operational issues, and provide proactive advice and support to meet evolving customer needs.

2.4 COMMON AND OTHER OM&A

Common Corporate OM&A expenditures are detailed in Exhibit E-04-01 and include Common Corporate Functions & Services (CCF&S), Planning, Digital and Technology Services (DTS), Operations, and other common support functions. These activities provide the enterprise capabilities required to operate and support the transmission business, including planning, operations, cyber and physical security, technology modernization, data and analytics, corporate services, and shared operational support. This cost category also captures Other OM&A costs, including the cost of sales incurred by Hydro One Transmission, as described in Exhibit E-04-06, and other corporate adjustments and cost recoveries, as described in E-04-02.

Common and Other OM&A expenditures support the stronger capabilities required by an evolving transmission system. Hydro One must operate a larger and more complex grid, support higher capital work volumes, improve data and system visibility, and maintain security capabilities commensurate with an evolving cyber and physical threat landscape. These expenditures support the safe, reliable and secure operation of Hydro One's transmission system and are further addressed in Exhibit E-04-01 and supporting Common and Other OM&A exhibits.

2.5 PROPERTY TAXES AND RIGHTS PAYMENTS

In addition to the above programs, the Transmission OM&A envelope includes property taxes and rights payments. Hydro One is subject to property taxes in accordance with the *Electricity Act 1998*, the *Municipal Act 2001*, the *Assessment Act 1990* and the *Indian Act*. Hydro One also pays annual fees for the right to cross and occupy properties owned by third parties, such as railway companies and governmental bodies. These expenditures are discussed in Exhibit E-09-06.

3.0 TRANSMISSION OM&A EXPENDITURES – VARIANCE ANALYSIS

The following sections discuss the key variances and expenditure trends for the Transmission OM&A programs across three time periods: (1) 2023 OEB-approved versus 2023 actuals, (2) 2023 to 2027 historical and bridge years, and (3) the 2028 test year.

3.1 2023 OEB-Approved VS. 2023 Actuals

In the last rebasing application, the OEB approved a 2023 test year Transmission OM&A envelope of $433.7M. Hydro One's actual OM&A expenditures in 2023 for Transmission were $507.7M, representing an upward variance of $73.9M primarily driven by incremental expenditures in Sustainment and Common and Other OM&A. This section explains the key variance drivers within Sustainment and Common and Other OM&A expenditures allocated to Transmission.

In 2023, Hydro One experienced significant sector-wide cost pressures as inflation increased following the COVID-19 pandemic. Within Sustainment OM&A, expenditures also reflected the prioritization of emerging demand-driven and mandatory work at the start of the rate period. These factors affected several Sustainment OM&A programs, including:

- **Right-of-Way Maintenance:** Actual expenditures of $46.8M were $13.1M (39%) higher than the planned expenditure level of $33.7M, driven by increased brush control and line-clearing activities on NERC-applicable transmission circuits required to maintain compliance with NERC FAC-003 vegetation management requirements.
- **Protection, Automation and Telecom Maintenance**: Actual expenditures of $47.0M were $9.1M (24%) higher than the planned expenditure level of $37.9M, reflecting the need to prioritize maintenance on protection and automation assets to sustain equipment performance and comply with applicable NERC standards and higher expenditures for essential Power System Telecom Services, including contractual leased services.

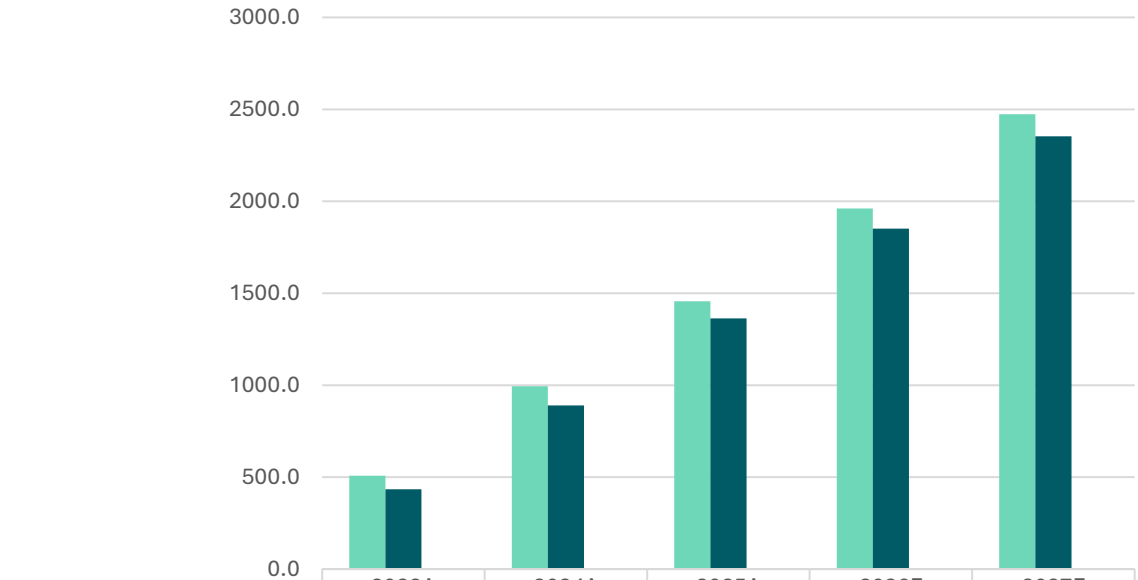
With respect to Common and Other OM&A, the increase was primarily driven by Hydro One’s reprioritization of expenditures toward security-related activities in response to the evolving cyber threat landscape. In 2023, actual expenditures for DTS and Security Management were $69.1M and $4.3M, respectively. These amounts were $12.5M (22%) and $1.0M (32%) higher than their respective planned expenditure levels of $56.5M and $3.3M. Hydro One increased these expenditures to strengthen its ability to monitor, detect,

and respond to potential vulnerabilities across its IT and OT environments, and to maintain the resilience and security of critical systems that support business and grid operations. Further details on Common Corporate OM&A are provided in E-04-01.

To manage these challenges, Hydro One reprioritized work in other parts of its Sustainment plan. For example, in 2023, the Power Equipment Maintenance programs were adjusted downward by approximately 11% relative to the planned expenditure levels so that Hydro One could meet its obligations in the demand-based programs noted above. However, even with these prudent reprioritizations, Hydro One's Transmission OM&A expenditures in 2023 were $73.9M higher than the OEB-approved amount, requiring Hydro One to adjust its management of OM&A expenditures over the remainder of the 2023-2027 rate period.

3.2 CURRENT RATE PERIOD: 2023 ACTUALS TO 2027 BRIDGE YEAR

Hydro One's 2023 challenges were not isolated events. Throughout the 2023 to 2027 period, the Company continued to face elevated work requirements and significant cost pressures. In response, Hydro One managed Transmission OM&A expenditures with a focus on maintaining the overall, cumulative 2023-2027 spending as close as possible to the funding available in rates. Where critical work could not be deferred or reprioritized, Hydro One elected to proceed with the work, resulting in approximately $120M of expenditures above the amounts funded in rates over the five-year period, as demonstrated in Figure 2.



	2023A	2024A	2025A	2026F	2027F
Cumulative Expenditures	507.7	994.7	1456.4	1961.0	2473.4
Cumulative OEB- Approved	433.7	890.3	1363.0	1851.5	2353.5
Variance	73.9	104.4	93.4	109.4	119.9

Figure 2: 2023 - 2027 Actual / Forecast Transmission OM&A vs Available Funding in Rates

To manage expenditures near available funding levels, Hydro One employed two key strategies during the current 2023-2027 rate period:

Trade-offs and reprioritization of planned work: Managing OM&A expenditures requires ongoing trade-offs, both reprioritizing work within individual programs to address the most pressing needs and shifting resources between programs to respond to system conditions as they evolve.

In Stations Sustainment OM&A, for example, power equipment maintenance increased from $47.7M in 2023 to $52.2M in 2025 primarily in relation to corrective maintenance, while security expenditures increased from $18.0M to $23.8M to address evolving threats and maintain NERC compliance. To accommodate these pressures, Hydro One deferred selected preventive maintenance activities, condition assessments, and transformer refurbishments within its Stations programs. As discussed in Exhibit E-02-02, these

decisions were informed by asset condition data and were limited to work that could be postponed while managing near-term reliability risks.

Within the Lines Sustainment OM&A programs, Hydro One prioritized vegetation management on NERC-applicable transmission circuits in the early years of the rate period while deferring brush control and line clearing on portions of the 115 kV network, reducing vegetation management expenditures from $46.8M in 2023 to $30.8M in 2025. Similarly, some overhead line patrols and condition assessments were reduced, with some programs operating at approximately 50% of planned levels and others deferred entirely. As a result, inspection intervals increased and the number of assets with unknown condition grew.

While these deferrals were carefully managed and limited to work that could be postponed temporarily without materially affecting transmission system performance, they have had cumulative consequences for the Stations Sustainment and Lines Sustainment OM&A programs. Within Stations, approximately 36% of transmission station buildings are now in poor condition, and are forecast to increase to over 55% by 2030 without intervention. Within Lines, over 2,000 line defects have accumulated as of the end of 2025, and recent LiDAR-based assessments confirmed a disproportionate concentration of urgent vegetation threats on deferred corridors. These conditions cannot be sustained without impacting long-term reliability and customer outcomes. The 2028 Test Year forecast provides the funding necessary to resume deferred maintenance, restore planned maintenance cycles, preserve asset health, and address the accumulated backlog (see Exhibit E-02-02 for program-level details).

Productivity and cost control: In parallel, Hydro One implemented productivity measures over the 2023–2027 period to identify efficiencies and reduce the costs, required to achieve planned outcomes. Hydro One Transmission achieved OM&A productivity savings of $5.8M in 2023, $8.4M in 2024 and $8.8M in 2025, as described in SPF Section 1.4.3.2. Examples include the PCB Tx – Bottom Filled Bushings initiative, which reduced PCB testing costs through a lower cost testing approach for applicable

units, and the X-Ray breaker inspection initiative, which uses X-Ray imaging instead of selective intrusive inspections to assess equipment condition while reducing inspection costs. Further initiative-level details are provided in SPF Section 1.4, Attachment 1. In addition to these productivity initiatives, Hydro One commenced an Enterprise Cost Optimization (ECO) Program during the current rate term to identify, develop and implement sustainable cost control measures. Transmission OM&A initiatives under the ECO Program generated additional savings of $7.9M in 2025, with $6.6M planned for 2026 as described in SPF Section 1.4.3.2, Table 3.

3.3 FORECAST PERIOD: 2028 TEST YEAR INCREASES

The 2028 Test Year forecast reflects that input costs have risen materially, the capital plan is significantly larger, customer and system work volumes are increasing, and Hydro One must support reliability, resilience, electrification, security and technology needs through targeted OM&A expenditures.

In the 2028 Test Year, planned expenditures within Transmission OM&A total $634.5M, which is an increase of $139.7M over the 2023-2027 annual average expenditures. Figure 3 illustrates the increase in Transmission OM&A expenditures from the 2023-2027 average to the 2028 Test Year forecast by OM&A category.

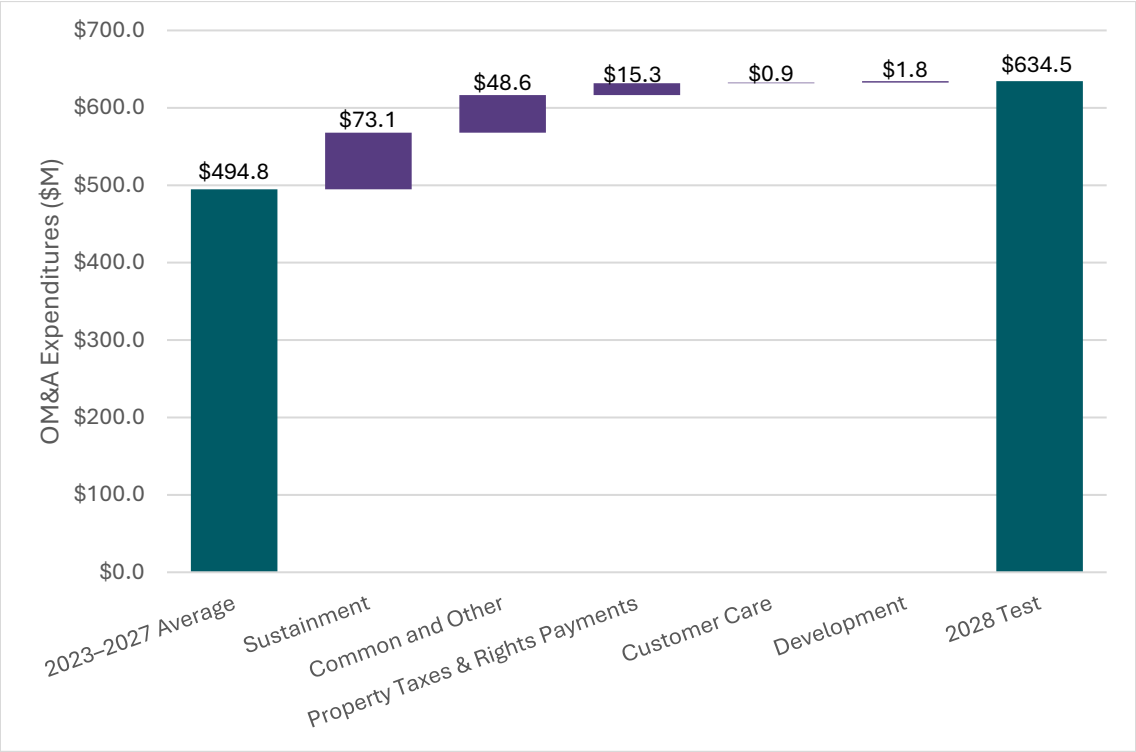


Figure 3: 2028 Test Year Forecast Compared to 2023-2027 Annual Average - Transmission OM&A Increase by Cost Category

As demonstrated in Figure 3, the increase in the 2028 Transmission OM&A forecast relative to the 2023-2027 average is primarily attributable to Sustainment (52%), Common and Other (35%) and Property Taxes and Rights Payments (11%). The key Sustainment OM&A drivers are discussed below, while Common and Other OM&A, and Property Taxes and Rights Payments are addressed in Exhibit E-04-01 and Exhibit E-09-06, respectively.

The following Sustainment programs account for the majority of the 2028 increase:

Lines – Vegetation Management: The 2028 forecast of $68.4M is $30.0M higher than the 2023-2027 annual average expenditure of $38.4M and $31.7M higher than the 2027 Bridge forecast of $36.7M. The increase addresses previously deferred vegetation work and maintains NERC FAC-003 compliance. Over 2023–2027, Hydro One prioritized vegetation management on NERC-applicable circuits (230 kV and above) and deferred

brush control and line clearing on portions of the 115 kV network. Recent patrols and LiDAR assessments confirm that deferred corridors have the highest concentrations of high-priority vegetation defects. For example, approximately 28% of imminent threats are on rights-of-way already one year beyond their target cycle, and 26% are on rights-of-way where maintenance is currently due. Deferred work carries higher costs due to increased vegetation growth and may require additional demand maintenance to avoid NERC FAC-003 clearance violations. (See Exhibit E-02-02, Section 3.2.)

Stations – Power Equipment Maintenance: The 2028 forecast of $66.1M is $16.7M higher than the 2023-2027 annual average expenditure of $49.4M and $18.5M higher than the 2027 Bridge forecast of $47.6M. The increase addresses the preventive maintenance backlog that accumulated during the 2023–2027 period. To manage within declining Sustainment funding, Hydro One deferred certain preventive maintenance activities for transformers, circuit breakers, and switches—selecting assets for deferral based on condition data, demographics, and equipment type. These deferrals must now be addressed: the ongoing condition data from preventive maintenance is necessary to identify equipment deficiencies, assess capital replacement needs, and prioritize corrective work. The 2028 forecast funds the clearing of a portion of the accumulated backlog, while restoring maintenance cycles and reducing future reliability risks. (See Exhibit E-02-02, Section 2.2.3.)

Stations – Site Infrastructure Maintenance: The proposed 2028 Test Year expenditure of $36.9M is $11.3M higher than the 2023-2027 annual average expenditure of $25.6M and $12.8M higher than the 2027 Bridge forecast of $24.1M. The increase is primarily driven by two objectives: first, corrective maintenance to address deficiencies in station building infrastructure, such as leaking roofs and drainage/sump pump equipment, that pose a risk to reliability and to the electrical equipment housed in power system buildings; and second, preventive maintenance to service critical and expensive building components such as HVAC systems and building shell to extend their serviceable life. Hydro One's Building Condition Assessment program confirms that approximately 36% of transmission station buildings are in poor condition (using the 5-Year Facility Condition

Index measure), and this is forecast to increase to over 55% by 2030 without intervention.[5] A large number of building components are at condition-adjusted end-of-life. Poor-condition components have a higher likelihood of failure, driving reactive break-fix spending that displaces preventive investment and accelerates further deterioration. Resuming an adequate level of preventive maintenance will interrupt this cycle, and the planned 2028–2032 capital investments are expected to further reduce the volume of assets in poor condition and reduce reactive maintenance requirements over the longer term. (See Exhibit E-02-02, Section 2.2.9.)

Stations – Protection, Automation and Telecom Maintenance: The proposed 2028 Test Year expenditure of $63.6M is $12.7M higher than the 2023-2027 annual average expenditure of $50.9M and $8.9M higher than the 2027 Bridge forecast of $54.7M. The increase is primarily driven by higher expenditures for Protection and Automation required to meet additional new and updated NERC and NPCC requirements, and higher expenditures for essential Power System Telecom Services, including the rising cost of contractual leased services. Within Protection and Automation, the increase is driven by two primary requirements: completing the remaining BES Protection System preventive maintenance activities required under the phased implementation of NERC reliability standard PRC-005-6, with the last implementation milestone coming due in 2028; and clearing the deferred non-BES Protection System preventive maintenance backlog to return those assets to their established maintenance cycles. Within Telecom, the increasing volume of telecom equipment increases the maintenance required to achieve regulatory compliance over time, and the cost of contractual services continues to rise. (See Exhibit E-02-02, Section 2.5.)

Lines – Overhead Maintenance: The proposed 2028 Test Year expenditure of $22.2M is $8.7M higher than the 2023-2027 annual average expenditure of $13.5M and $8.1M higher than the 2027 Bridge forecast of $14.1M. The increase is primarily driven by the following factors.

[5] GSP, Section 4.11, Investment Summary Document G-GP-04, p. 8, Table 3 and p. 51.

- Resuming preventive maintenance activities on cycle: During 2023–2027, foot, helicopter, and thermovision patrols were reduced to approximately 50% of planned levels, doubling the time between patrols and leaving half of the transmission system without its planned inspections, resulting in missed defects.
- Completing required asset condition assessments: The 2028 plan includes the execution of all required asset condition assessments required under Hydro One's Asset Strategy, while also addressing deferrals from 2023–2027 that increased the number of assets with unknown condition. Many condition assessments were reduced or deferred, resulting in increased safety and reliability risk associated with transmission line components such as U-bolt hardware, insulators, wood poles, steel structures, conductors, and shield wires.
- Addressing the accumulated defect backlog: The 2028 forecast includes funding to address the backlog of medium- and low-priority defects that could not be sufficiently addressed during 2023-2027 as work was reprioritized to meet higher-priority operational requirements. (See Exhibit E-02-02, Section 3.3.)

These increases were offset by a $10.8M reduction in Stations Sustainment – Security (from $22.5M in the 2027 Bridge Year to $11.7M in the 2028 Test Year), which was driven by the re-categorization of two security subprograms from Transmission Sustainment to Common and Other (see Exhibit E-04-04, Section 2.4.1 for details).

4.0 REASONABLENESS OF PROPOSED EXPENDITURES

Hydro One’s proposed Transmission OM&A expenditures are reasonable because they are grounded in an integrated planning process, informed by customer and system needs, and paced to balance operational requirements with customer rate impacts. The plan supports the continued safe and reliable operation of the transmission system while addressing work reprioritization, cost pressures, evolving customer expectations, severe weather, electrification, cyber and physical security requirements, and sector transformation, including the accumulated impacts of these factors over the forecast period.

The 2028 OM&A forecast is not simply an increase in expenditures compared to the current rate term. It reflects the funding required to establish a sustainable operating baseline for the next rate period. Hydro One's 2023 to 2027 experience demonstrates that the Company made difficult operating decisions to manage as close as possible to the rate-period envelope. For the next rate period, the proposed funding supports the restoration of deferred work where needed, enables the delivery of a much larger capital program, maintains reliable and resilient service, and builds the capabilities required for Ontario's electricity transition.

Hydro One's 2028 Transmission OM&A plan of $634.5M was developed through a bottom-up planning process grounded in asset condition data, operational requirements, and the maintenance and operational activities necessary to support and execute Hydro One's Transmission System Plan (TSP). The OM&A forecast reflects customer needs and preferences, promotes the OEB's Renewed Regulatory Framework (RRF) outcomes, and is supported by Hydro One's demonstrated capability to effectively prioritize and deliver OM&A programs. The planning context, customer engagement, alignment with RRF outcomes, and Hydro One's ability to execute the plan are described in the subsections below.

Hydro One also monitors performance and cost efficiency through operational and financial metrics that assess program delivery and cost control over time. The Transmission Scorecard tracks OM&A efficiency, work accomplishment, and cost control metrics, including OM&A per Gross Fixed Asset Value, line clearing cost per kilometer, and brush control cost per hectare. Historical performance and forecast targets are provided in TSP Section 2.5. In addition, an external benchmarking analysis of Common Corporate Costs assessed the efficiency and effectiveness of Hydro One's centralized corporate functions. Further details are provided in Exhibit E-04-02, with the study included as Attachment 1.

4.1 PLANNING CONTEXT

As described in SPF Section 1.7, Hydro One's 2028 Transmission OM&A forecast was developed on a bottom-up basis, informed by the actual condition of Hydro One's

transmission assets and the needs of its customers. Consistent with Hydro One's lifecycle approach to system planning and asset management, planning teams developed the OM&A plan in coordination with the capital investments set out in the TSP. The plan was developed through a risk assessment of candidate maintenance and operational activities based on safety, reliability, and environmental risk, and considered customer input, management insight, and the Company's strategic priorities and objectives. The resulting operational expenditure plan is responsive to the outcomes of the TSP (TSP Section 2.1).

4.1.1 CUSTOMER ENGAGEMENT

As detailed in SPF Sections 1.6 and 1.7, feedback from customer engagement directly informed and shaped the development of the investment plan. In 2024 and 2025, Hydro One retained Innovative Research Group (IRG) to conduct Hydro One's multi-phase customer engagement process to inform and refine the investment plans in this application, including both the capital and OM&A plans (the IRG Study). The customer priorities identified through this process, including system reliability, asset stewardship, and service quality, are delivered in part through OM&A-funded maintenance, inspection, and operational activities.

The IRG Study results indicate strong support for Hydro One's draft investment plans, including the operational expenditures necessary to maintain system reliability and asset condition. As stated in the IRG Overview Report (see SPF Section 1.6, Attachment 1): "Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans."

Key customer feedback from Phase II, in respect of transmission, included the following:

- Across all customer types, a majority or near majority of customers selected Hydro One's draft plan level of spending as it relates to transmission investments in keeping pace with transmission renewal, and stewardship of the transmission system. The proposed OM&A expenditures deliver on these preferences:

maintaining equipment reliability and system stewardship requires preventive maintenance, condition assessments, and vegetation management.

- Customers expressed strong support for the replacement of aging and deteriorating transmission system assets to manage the risk of equipment failure and support growth across the province. These include the replacement of transmission station transformers and breakers, and high-impact underground transmission cables. These capital renewal activities depend on the OM&A-funded condition assessment, inspection, and testing programs that identify assets approaching end-of-life and prioritize capital investment accordingly.
- Customers also expressed strong support for investments to enhance Hydro One's stewardship of the transmission system. A majority of customers support the draft plan, including replacing at-risk transmission lines, reinforcing wood poles, and extending the life of steel towers and accelerating the clearing of overgrown trees. The OM&A plan delivers these stewardship outcomes through vegetation management programs that maintain safe clearances and protect line infrastructure, overhead line patrol and inspection programs that detect defects before they result in failures, and preventive maintenance activities that extend asset service life and defer the need for capital replacement.

As detailed in SPF Section 1.7, Hydro One refined the transmission investment plans based on the results of its customer engagement. This refinement also considered other factors, including the alignment between asset needs and overall costs, resulting in plans that reflect customer needs and preferences alongside other planning factors. The OM&A plan is calibrated to deliver the maintenance and operational activities required to achieve the reliability and stewardship outcomes customers identified as priorities.

4.2 ALIGNMENT WITH RRF OUTCOMES

The proposed Transmission OM&A plan is designed to advance each of the OEB's four RRF outcomes:

- **Customer Focus:** The OM&A plan supports power quality, equipment availability, and customer reliability by funding preventive maintenance, inspection, and condition assessment activities that sustain transmission asset performance. Customer Care OM&A supports responsive and proactive service to transmission-connected customers through dedicated Account Executives.
- **Operational Effectiveness:** The OM&A plan supports top-tier safety performance by funding safety-critical maintenance activities, mandatory compliance programs, and environmental protection measures. Sustainment OM&A maintains and improves long-term reliability by restoring deferred preventive maintenance cycles, addressing accumulated work backlogs, and ensuring that condition data generated through ongoing maintenance informs capital replacement prioritization.
- **Public Policy Responsiveness:** The OM&A plan ensures compliance with mandated statutory and regulatory obligations, including NERC Reliability Standards (PRC-005-6, FAC-003, CIP standards), the Transmission System Code, and applicable environmental legislation. Increased OM&A funding for Protection, Automation and Telecom maintenance, vegetation management, and security is directly driven by these compliance requirements.
- **Financial Performance:** The OM&A plan supports reasonable and stable rate impacts by phasing the restoration of deferred maintenance activities over a measured timeline.

4.3 ABILITY TO EXECUTE THE PLAN

Hydro One has demonstrated its ability to manage Transmission OM&A programs effectively through the 2023–2027 rate period. As discussed in Sections 1.0 and 3.0 of this Exhibit, Hydro One managed its total Transmission OM&A expenditures toward the total funding levels established in the previous rebasing application, while proceeding with critical work that could not prudently be deferred. Historical unit costs, work volumes, and

productivity expectations have been applied to inform the development of the forecast OM&A expenditure levels on a program-by-program basis.

The OM&A plan also accounts for the workforce and operational resources required to support the delivery of the capital program set out in the TSP, as discussed further in Exhibit E-02-05. Capital project execution relies on asset planning, engineering support, and outage coordination. Hydro One's demonstrated ability to manage OM&A expenditures prudently during the current rate period, while reprioritizing work to address system needs, supports the feasibility of the proposed 2028 OM&A plan.

CHAPTER 2 APPENDIX 2-JA, 2-JB, 2-JC AND 2-L – TRANSMISSION OM&A EXPENDITURES

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TRANSMISSION SUSTAINMENT OM&A

1.0 SUMMARY OF TRANSMISSION SUSTAINMENT OM&A

Transmission Sustainment OM&A consists of expenditures required to maintain existing transmission system equipment and facilities to ensure they continue to function safely and as originally designed. The Transmission Sustainment OM&A expenditures allow Hydro One and Hydro One Sault Ste. Marie LP (HOSSM) to maintain system reliability and service quality, while satisfying applicable legislative, regulatory, environmental, and safety requirements. See Exhibit E-02-06 for HOSSM's OM&A expenditures.

Hydro One's Sustainment OM&A program is organized into three categories:

- Stations, which funds the work required to maintain existing assets located within transmission stations, including existing protection, control, and telecommunication facilities;
- Lines, which funds the work required to maintain overhead transmission lines and underground cables, including vegetation management on transmission line rights-of-way; and,
- Engineering and Environmental Support, which funds the specialized and administrative support needed to assist with decision-making processes in managing the transmission assets.

1.1 HYDRO ONE TRANSMISSION SUSTAINMENT OM&A

Table 1 below sets out Hydro One's planned expenditures for the 2028 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each of the three Sustainment OM&A categories.

Table 1 - Hydro One - Summary of Sustainment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	F/cast	F/cast	F/cast
Stations	166.8	167.5	169.8	169.1	167.0	199.4
Lines	67.9	62.3	47.4	55.2	55.5	98.4
Engineering & Environmental Support	6.4	7.3	7.2	7.1	7.3	8.1
Total Sustainment	**241.1**	**237.1**	**224.5**	**231.4**	**229.7**	**305.9**

Hydro One's Total Sustainment OM&A expenditure for the 2028 Test Year is $305.9M. Adjusting the last rebasing year's (2023) actual sustainment expenditures using the applicable OEB annual inflation factors results in a comparable amount of $288.8M.[1] This forecast is therefore $17.1M, or 5.9%, higher than this inflation-adjusted 2023 actual amount.

To manage expenditures over the historical 2023-2027 period, Hydro One undertook a prioritization exercise within its Sustainment OM&A programs. During this period, sustainment expenditures were affected by the need to redirect funding to address emerging requirements in demand-driven programs, as well as mandatory programs such as mandatory compliance, security, and telecommunications requirements, which experienced cost increases. As a result, certain maintenance activities across power equipment, lines maintenance, and vegetation management programs were temporarily deferred.

While these deferrals were necessary to address higher-priority and mandatory needs within the available funding envelope, they are not sustainable over the long term. Continued deferrals would increase the risk of asset deterioration, result in additional deferred maintenance activities and assets with unknown condition, and increase future reliability risks and reactive maintenance costs.

[1] 2023 actual expenditures adjusted by OEB inflation to 2028 = $241.1M x (1+5.4%) * (1+3.7%) * (1+3.5%) * (1+2.9%)* (1+2.9%) = $288.8M. (($305.9M/$288.8M) – 1)*100 = 5.9%.

The 2028 Test Year forecast enables the resumption of previously deferred maintenance activities while providing the funding required to restore sustainable maintenance levels. Resuming these activities is critical to restoring planned maintenance cycles, addressing the accumulated deferred work over the rate period, preserving asset health, and mitigating future reliability and operational risks. The specific impacts of these prioritization decisions and the importance of resuming deferred work are discussed in the program-level sections below.

On an unadjusted basis, the 2028 Test Year forecast represents a $64.8M (26.9%) increase relative to 2023 actual expenditures and a $73.1M (31.4%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure is primarily driven by sustained inflation and increased expenditures for vegetation management, station power equipment maintenance, site infrastructure maintenance, Protection, Automation and Telecom maintenance, and overhead lines maintenance, partially offset by lower Stations Sustainment Security expenditures resulting from the recategorization of two security subprograms[2] to Common and Other OM&A. These drivers are summarized below.

1.2 TOP DRIVERS OF THE 2028 SUSTAINMENT OM&A

The principal drivers of the 2028 Test Year increase are described below. These drivers reflect the resumption of deferred sustainment work, and maintenance activities needed to preserve asset condition, support reliability, and mitigate future operational risks.

Power Equipment Maintenance OM&A – Hydro One plans to increase expenditures on preventive maintenance for transmission power equipment to resume deferred maintenance activities, sustain future-year maintenance activities without creating further deferrals, and mitigate future reliability risks.

[2] See Exhibit E-04-04, Section 2.4.1 for details

Between 2023 and 2027, Hydro One prioritized and deferred selected preventive maintenance activities, condition assessments, and transformer refurbishments to accommodate increased funding requirements in areas such as telecommunications and security. These deferrals were identified using asset condition data and limited to work that could be postponed temporarily without materially affecting transmission system performance.

To maintain the safety and reliability of the transmission system, Hydro One must return preventive maintenance programs to planned levels. Resuming this work will ensure maintenance activities are completed on planned cycles, support the early identification of assets requiring capital replacement, and reduce the risk of unplanned equipment failures and transmission outages.

Site Infrastructure Maintenance – Hydro One plans to increase expenditures on planned and preventive maintenance of site facilities and infrastructure at transmission stations, to address deficient building components and to extend the useful life of critical, high-cost systems before they fail.

Lines Sustainment – Hydro One plans to increase expenditures to resume preventive maintenance activities on planned cycles, complete required asset assessments, address the inventory of low- and medium-priority defects that accumulated due to deferred work during 2023 to 2027, and support vegetation management activities on transmission line rights-of-way. The increase is also driven by findings through LiDAR-based Virtual Patrols, which improve visibility into vegetation-related defects and clearance risks and support risk-based work planning.

2.0 STATIONS SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide further detail on the Stations Sustainment OM&A categories, including the related programs and sub-programs, Test Year expenditures, and variance analysis.

Transmission stations are used for the delivery of power, voltage transformation, and switching. They serve as connection points for both load customers and generator customers. Transmission stations contain power system equipment that is further described in TSP Section 2.2, which presents information on the major transmission station components that comprise Hydro One's transmission system, including each component's description, purpose, demographics, condition, performance, and asset lifecycle strategy.

The Stations Sustainment OM&A covers expenditures that maintain the performance of assets located within Hydro One's transmission stations. The Stations Sustainment OM&A program is divided into the following seven program categories: (i) Land Assessment and Remediation; (ii) Environmental Management; (iii) Power Equipment Maintenance; (iv) Ancillary Systems Maintenance; (v) Protection, Automation and Telecom Maintenance; (vi) Security; and (vii) Site Infrastructure Maintenance.

2.1 HYDRO ONE - STATIONS SUSTAINMENT OM&A

Table 2 below sets out Hydro One's planned expenditures for the Test Year, along with the forecast and actual spending level for the Bridge and Historical Years.

Table 2 - Hydro One - Stations Sustainment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Land Assessment and Remediation	0.9	0.9	0.1	0.4	0.4	0.4
Environmental Management	17.5	11.0	9.6	8.9	8.8	10.2
Power Equipment Maintenance	47.7	51.2	52.2	48.4	47.6	66.1
Ancillary Systems Maintenance	9.4	8.2	8.3	9.2	8.9	10.5
Protection, Automation and Telecom Maintenance	47.0	48.7	49.8	54.3	54.7	63.6
Security	18.0	20.9	23.8	23.0	22.5	11.7
Site Infrastructure Maintenance	26.4	26.6	25.9	24.9	24.1	36.9
Total	**166.8**	**167.5**	**169.8**	**169.1**	**167.0**	**199.4**

The 2028 Test Year expenditure for Hydro One's Station Sustainment OM&A is $199.4M. This is a $32.6M (19.5%) increase relative to 2023 actual expenditures and a $31.4M (18.7%) increase relative to the average annual expenditures over the 2023-2027 period.

With respect to need and excluding the impact of inflation, the proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 periods is primarily driven by work in the following programs:

- Power Equipment Maintenance – increased expenditures to resume selected preventive maintenance activities for transformers, circuit breakers, and switches, restore planned maintenance cycles, and support the identification of equipment requiring capital replacement.
- Protection, Automation and Telecom Maintenance – increased expenditures to meet additional maintenance requirements, address deferred work, and support essential power system telecommunication services.
- Site Infrastructure Maintenance – increased expenditures for planned and corrective maintenance of station facilities and building infrastructure to address deficient components and support continued serviceability.

2.2 STATIONS SUSTAINMENT OM&A - PROGRAM DETAILS

Further details on the aforementioned drivers, along with descriptions of the Stations programs and their respective Test Year expenditures, are provided in the sections below.

2.2.1 STATIONS SUSTAINMENT OM&A - LAND ASSESSMENT AND REMEDIATION

Through the Land Assessment and Remediation (LAR) program, Hydro One assesses the level of contamination on its properties. This program is focused on the mitigation and remediation of historical off-property contamination from transmission station sites and real estate facilities that may pose a risk to the public and/or Hydro One staff. Where appropriate, LAR work is coordinated with refurbishment and capital work.

The LAR program prioritizes sites for environmental assessment and remediation work based on two factors: (i) the type and level of contamination that exceeds Ministry of

Environment, Conservation and Parks (MOECP) standards; and (ii) the potential for the contaminants to cause adverse effects to human health and/or the environment.

The LAR program consists of the following components: site assessment, site remediation, and site management work. Site assessments involve information gathering and soil and groundwater testing to identify and prioritize sites. Site remediation is performed where contamination is identified, and includes the development of a remediation plan. This plan typically includes the treatment, removal, or management of the identified contamination. Site management work begins once a site has been assessed and remediated. It includes the monitoring and management of any residual on-site contamination, as well as the management of installed controls (e.g., barriers and long-term treatment systems).

Table 3 below sets out Hydro One's planned expenditures for LAR program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 3 - Hydro One - Land Assessment and Remediation OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Land Assessment and Remediation	0.9	0.9	0.1	0.4	0.4	0.4

The 2028 Test Year expenditure for Hydro One's Land Assessment and Remediation OM&A is $0.4M. The 2028 Test Year forecast is generally in line with 2023 actual expenditures and the average annual expenditures over the 2023-2027 rate period.

2.2.2 STATIONS SUSTAINMENT OM&A - ENVIRONMENTAL MANAGEMENT

The Environmental Management program is an ongoing program that focuses on mitigating and remediating contamination located within and beyond the station fence. It involves managing, testing, and disposing of regulated waste that develops as part of Hydro One's normal business operations. This program ensures that Hydro One is able

to satisfy its obligations related to environmental regulations and policies associated with its transmission station equipment.

The Environmental Management program consists of the following four activities: (i) Waste Management, (ii) Transformer Oil Leak Reduction, (iii) Preventive and Corrective Maintenance, and (iv) Environmental Compliance and Emergency Response Plan Updates.

Hydro One's proposed funding for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, is set out in Table 4 below.

Table 4 - Hydro One - Environmental Management OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Waste Management	8.8	5.5	3.2	2.9	2.9	2.4
Transformer Oil Leak Reduction	2.8	2.7	4.4	2.6	2.5	4.3
Preventive and Corrective Maintenance	4.5	1.4	1.3	2.7	2.6	2.7
Environmental Compliance and Emergency Response Plan Updates	1.4	1.4	0.7	0.8	0.7	0.8
Total	**17.5**	**11.0**	**9.6**	**8.9**	**8.8**	**10.2**

The 2028 Test Year expenditure for Hydro One's Environmental Management OM&A is $10.2M. This is a $7.3M (41.7%) decrease relative to 2023 actual expenditures and a $1.0M (8.6%) decrease relative to the average annual expenditures over the 2023-2027 period. The drivers behind the decrease are discussed in the following subsections.

2.2.2.1 ENVIRONMENTAL MANAGEMENT - WASTE MANAGEMENT

The program funds activities that manage regulated waste, including but not limited to lead, cadmium, and mercury, which are the subject of provincial and federal regulatory requirements applicable to Hydro One.[3]

Actual and forecast expenditures through 2026 are higher primarily due to PCB remediation activities required to meet applicable regulatory requirements. As this work is expected to be completed by 2026, no PCB-related costs are forecast in 2027 or 2028.

Table 5 below sets out Hydro One's planned expenditures for this program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 5 - Hydro One - PCB Retirement and Waste Management OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Waste Management	8.8	5.5	3.2	2.9	2.9	2.4

The 2028 Test Year expenditure for Hydro One's PCB Retirement and Waste Management OM&A is $2.4M. This is a $6.4M (72.7%) decrease relative to 2023 actual expenditures and a $2.3M (48.5%) decrease relative to the average annual expenditures over the 2023-2027 period.

This is generally in line with ongoing regulated waste management requirements and lower than the historical average, reflecting the completion of PCB remediation activities in 2025 and 2026 and the absence of PCB-related costs in 2027 and 2028.

[3] O. Reg. 362: *Waste Management – PCB's*; O. Reg. 347: *General – Waste Management*; and *PCB Regulations*, SOR/2008-273.

2.2.2.2 ENVIRONMENTAL MANAGEMENT - TRANSFORMER OIL LEAK REDUCTION

Hydro One mitigates transformer oil leaks through the Transformer Oil Leak Reduction program. As transformers age, they become susceptible to leaks due to the effects of thermal cycling and the gradual deterioration of sealing gaskets. Oil leaks are one of the most common deficiencies found in transformers and are a significant contributor to transformer forced outages. Active oil leaks also provide a path of moisture ingress into a transformer's internal winding, which, in Hydro One's experience, has been one of the major causes of transformer Class 1 failures.[4] For example, the Richview TS T8 transformer caught fire due to an internal failure caused by moisture. Recently, the Seaforth T2 transformer, which was a high-risk unit planned for replacement, required a significant OM&A investment to stop oil leaks and complete site remediation.

When first discovered, transformer oil leaks are repaired on a temporary basis under the corrective program to mitigate any immediate environmental concerns. These temporary repairs use an exterior application of sealant until a more permanent solution can be implemented. The permanent solution involves draining the transformer and re-gasketing, which is a maintenance process to replace worn, degraded, or leaking gaskets on industrial equipment. It requires an outage, staff with a specific skill set, and specialized oil processing equipment.

Table 6 below sets out Hydro One's planned expenditures for this program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

[4] A Class 1 failure is a transformer failure that cannot be fixed at the site.

Table 6 - Hydro One - Transformer Oil Leak Reduction OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Transformer Oil Leak Reduction	2.8	2.7	4.4	2.6	2.5	4.3

Hydro One's 2028 Test Year expenditure for Transformer Oil Leak Reduction OM&A is $4.3M. This is a $1.5M (53.6%) increase relative to 2023 actual expenditures and a $1.3M (43.7%) increase relative to the average annual expenditures over the 2023-2027 period.

With respect to need, the proposed 2028 Test Year forecast expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by deferred work and higher costs. Stockpiled units were identified in prior-year assessments and deferred due to funding limits and relatively slower leak rates compared to units prioritized for repair. The longer these units remain unaddressed, the greater the risk that a more severe leak could result in an unplanned outage or failure. While a faster pace would be preferred, Hydro One expects to complete 4 to 5 transformer leak reduction projects per year based on available funding over the 2023-2027 period.

2.2.2.3 ENVIRONMENTAL MANAGEMENT - PREVENTIVE AND CORRECTIVE MAINTENANCE

The preventive maintenance component of the Preventive and Corrective Maintenance Program ensures that spill containment systems are inspected and operated as designed. The program also ensures that non-functioning mechanical components (such as pumps, sensors, and relays) are used in oil/water separators to control the effluent from transformer spill containment pits are repaired or replaced, as required.

The corrective maintenance component of the program includes repairing spill containment systems that require mitigation. The program also maintains spill containment capacity for non-functioning spill containment systems by removing and disposing of the rainwater, containing and cleaning up insulating fluid spills as they occur, and undertaking

all other actions necessary to mitigate environmental risks posed by transmission equipment problems and failures.

The Preventive and Corrective Maintenance program allows Hydro One to meet its corporate Environmental Policy objectives, maintain compliance with MOECP requirements, minimize risks to human health and the environment, and mitigate Hydro One's exposure to legal and reputational risks.

Table 7 below sets out Hydro One's planned expenditures for this program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 7 - Hydro One - Preventive and Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive and Corrective Maintenance	4.5	1.4	1.3	2.7	2.6	2.7

Hydro One's 2028 Test Year expenditures for Environmental Management's Preventive and Corrective Maintenance OM&A is $2.7M. This is a $1.8M decrease relative to 2023 actual expenditures and a $0.2M increase relative to the average annual expenditures over the 2023-2027 period.

2.2.2.4 ENVIRONMENTAL MANAGEMENT - ENVIRONMENTAL COMPLIANCE AND EMERGENCY RESPONSE PLAN UPDATES

The Environmental Compliance category encompasses activities required to comply with MECP Environmental Compliance Approvals (ECAs), which include a number of common and site-specific requirements (e.g., regular testing of effluent).[5]

Emergency Response Plans (ERPs) are station-specific emergency response and evacuation plan documents that are kept at each transmission station. They are an effective tool for planning, preparing for, and responding to emergencies. The ERPs

[5] ECAs, formerly known as Certificates of Approval.

ensure that the risk of harm to employees, contractors, the public, the environment, and the physical assets of Hydro One in the event of an emergency is minimized. Funding under this program ensures that all ERPs contain up-to-date and accurate site-specific information.

Table 8 below sets out Hydro One's planned expenditures for this program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 8 - Hydro One - Environmental Compliance and Emergency Response Plan OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Environmental Compliance and Emergency Response Plan Updates	1.4	1.4	0.7	0.8	0.7	0.8

Hydro One's Environmental Compliance and Emergency Response Plan Updates expenditure for the 2028 Test Year is $0.8M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the historical average over the 2023-2027 period.

2.2.3 STATION SUSTAINMENT OM&A - POWER EQUIPMENT MAINTENANCE

Hydro One's transmission power equipment includes 722 transformers, 4,691 circuit breakers, as well as switches, insulators, bus work, instrument transformers, capacitor banks, and reactors installed in 297 transmission stations. Maintenance of these assets is required to sustain power equipment performance and to maintain transmission system safety and reliability, refurbish power equipment to preserve the equipment's expected service life and reliability, and assess poor-equipment condition warranting replacement under Hydro One's capital renewal expenditure plan.

The Power Equipment Maintenance program is divided into the following five categories: (i) Preventive Maintenance, (ii) Corrective Maintenance, (iii) Transformer Refurbishments, (iv) Breaker Refurbishments, and (v) Other Maintenance and Inspection Programs.

Table 9 below sets out Hydro One's planned expenditures for the Test year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each category.

Table 9 - Hydro One - Power Equipment Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	13.6	13.1	14.0	15.6	15.3	22.1
Corrective Maintenance	28.9	32.7	33.0	25.9	25.3	35.4
Transformer Refurbishment	2.6	2.3	1.7	3.1	3.0	4.5
Breaker Refurbishment	0.7	0.9	1.0	1.2	1.5	1.2
Other Maintenance and Inspection Programs	1.9	2.2	2.6	2.6	2.6	2.9
Total	**47.7**	**51.2**	**52.2**	**48.4**	**47.6**	**66.1**

The 2028 Test Year expenditure for Hydro One's Power Equipment Maintenance is $66.1M. This is a $18.4M (38.6%) increase relative to 2023 actual expenditures and a $16.7M (33.8%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 is primarily driven by the need to restore preventive maintenance activities on transmission power equipment and sustain maintenance programs at planned levels. This funding will enable Hydro One to resume deferred maintenance activities and support future maintenance requirements without creating further deferrals.

During the 2023-2027 period, Hydro One deferred maintenance using updated asset condition data to identify assets for which certain preventive maintenance activities, such

as intrusive internal inspections and some diagnostics, could be deferred for a short period of time while managing the risk to transmission system performance and reliability.

These preventive maintenance activities are necessary to comply with manufacturer guidelines and industry standards, and to test equipment and verify their performance. Hydro One relies on condition data collected during preventive maintenance to assess the need for, prioritize, and execute new replacement candidates that may arise and other preventive and corrective maintenance. Thus, Hydro One must resume the proposed level of preventive maintenance to ensure that the necessary maintenance activities are completed in a timely manner and new capital replacement candidates are identified. This, in turn, will reduce the risk of unplanned equipment failures that could affect the reliability of the transmission system.

Furthermore, Hydro One expects to add five new transformer stations to the total number of stations during the 2028-2032 period. The power equipment in these new stations, as well as the newly in-serviced equipment in existing stations, require regular preventive maintenance. This includes condition and diagnostic testing to ensure proper operation and performance in the “infancy” stages of their deployment.

2.2.3.1 POWER EQUIPMENT MAINTENANCE - PREVENTIVE MAINTENANCE

Hydro One performs preventive maintenance to ensure the safe and reliable operation of its transmission system. The preventive maintenance activities are also undertaken to meet obligations under section 7.1.1 of the Transmission System Code, which requires Hydro One to “inspect, test and monitor its transmission facilities to ensure continued compliance with all applicable standards and instruments.”

Hydro One’s preventive maintenance program places priority on condition assessment activities – including visual inspections, oil analysis, function testing, and equipment performance monitoring as well as more intrusive condition-based maintenance. The different types of power equipment have varying maintenance activities. The following are

examples of maintenance activities for transformers, breakers, and switches that Hydro One performs:

- Regular visual inspections to identify and record defects;
- Recording of pressures and temperatures to ensure that equipment is operating within appropriate specifications and to identify oil leaks;
- Testing the function of various equipment elements and alarms to ensure continued operation and reliability, and topping up oil as required;
- Diagnostic testing such as circuit breaker trip timing, contact resistance, oil analysis for dissolved gas, moisture content, and dielectric strength; and
- Condition based Selective intrusive maintenance, X-Ray imaging to further assess equipment condition, check contacts, clean and lubricate, replace seals, and complete minor repairs as required.
- NERC mandated maintenance on pressure relays on Transformers and Reactors.

The frequencies of these activities vary depending upon the make, model type, and condition of the subject power equipment. The Preventive Maintenance program expenditures are based on the volume and type of maintenance work required to be completed during the calendar year.

Table 10 below sets out Hydro One's planned expenditures for this program for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 10 - Hydro One - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	13.6	13.1	14.0	15.6	15.3	22.1

The 2028 Test Year expenditure for Hydro One's Power Equipment Preventive Maintenance is $22.1M. This is an $8.5M (62.5%) increase relative to 2023 actual

expenditures and a $7.8M (54.3%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the need to resume deferred preventive maintenance activities and sustain future year maintenance requirements. Additional funding is required to address maintenance activities deferred to manage within the OM&A funding envelope during the 2023-2027 period.

By the end of 2027, deferred maintenance work at Hydro One is projected to exceed $34M. The Test Year 2028 forecast of $22.1M includes:

- $18.7M to sustain Power Equipment preventive maintenance activities and prevent further growth of work deferral.
- $3.4M annually to address the accumulated deferred maintenance work. Over the rate period, this level of funding is expected to support work equivalent to approximately 50% of the inventory projected at the end of 2027.

Currently, Hydro One is approaching the deferral of preventive maintenance activities (time-based and condition based) by using updated asset condition data, demographics, age, equipment type, make and model etc. to identify assets for which certain preventive maintenance activities can be deferred for a short period of time while managing the risk to system performance and reliability. The preventive maintenance activities that are being deferred during 2023-2027 (e.g., breaker and transformer diagnostics, intrusive maintenance) need to be resumed to identify equipment deficiencies, and because the ongoing condition data from these activities is necessary to properly assess the need for, prioritize, and execute new replacement candidates that may arise. Thus, to mitigate the risk of unplanned equipment failure impacting the reliability of the transmission system, Hydro One must resume the proposed level of preventive maintenance to ensure that the necessary maintenance activities are completed in a timely manner and new capital replacements candidates are identified.

The data obtained through preventive maintenance is also required to determine whether major overhaul maintenance, corrective repairs, or refurbishments are necessary, and the extent to which any maintenance activities may be deferred. For example, in order to determine whether it is appropriate to defer intrusive repair or refurbishment of a breaker, Hydro One must have data on the condition and performance of the breaker. This data is obtained through time-based inspections such as visual inspections, thermography, and diagnostic testing. The same applies in respect of other power equipment such as transformers, switches, and reclosers. The data from these time-based inspections allows Hydro One to make appropriate, risk-based decisions regarding which equipment needs major overhaul maintenance and which maintenance activities can be deferred for a short period of time, without unduly jeopardizing the performance of the transmission system.

In light of the foregoing, Hydro One's Preventive Maintenance expenditures are forecast to increase in the 2028 Test Year relative to the 2023-2027 period to resume deferred maintenance activities that can no longer be deferred without compromising system performance and reliability.

2.2.3.2 POWER EQUIPMENT MAINTENANCE - CORRECTIVE MAINTENANCE

Corrective maintenance work is required to repair power equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned repairs based on condition assessments and unplanned (i.e., demand) work, including emergency response. Planned corrective maintenance addresses issues outside regular preventive maintenance activities, including defects identified during normal condition assessments. Where possible, planned corrective maintenance is bundled or coordinated with other work to achieve efficiency.

Demand corrective maintenance includes all unscheduled, non-programmed maintenance necessitated by unforeseen problems and/or equipment failures. Emergency response may include a preliminary investigation and minor repairs following equipment failure. Typically, emergency work is required to address the risk of harm and/or damage to employee safety, public safety, system reliability, or the environment and therefore cannot be deferred

Table 11 below sets out Hydro One's planned expenditures for this program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 11 - Hydro One - Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Corrective Maintenance	28.9	32.7	33.0	25.9	25.3	35.4

The 2028 Test Year expenditure for Hydro One's Power Equipment Corrective Maintenance is $35.4M. This is a $6.5M (22.5%) increase relative to 2023 actual expenditures and a $4.9M (16.2%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to 2026 is primarily driven by the need to address deferred medium to low priority planned corrective repairs which were deferred to prioritize other work. The number and severity of corrective maintenance issues addressed each year is variable. The proposed 2028 Test Year expenditure is based on actual costs in historical years, with the addition of deferred medium to low priority planned corrective repairs

Currently, Hydro One has an accumulated inventory of deferred corrective maintenance work valued at approximately $22M, which is expected to continue growing through the end of 2027.

The Test Year 2028 forecast of $35.4M is comprised of:

- $20.9M for demand corrective work.
- $14.5M for planned corrective work, including:
    - $12.3M for corrective work identified during the year.
    - $2.2M annually to begin addressing the accumulated deferred corrective maintenance work. Over the rate period this level of funding is expected to support work equivalent to approximately 50% of the inventory projected at the end of 2027.

2.2.3.3 POWER EQUIPMENT MAINTENANCE - TRANSFORMER REFURBISHMENT

Refurbishment of Hydro One's transformer fleet is required to preserve the transformer's expected service life and reliability, and to mitigate the need for premature replacement. Refurbishment includes addressing deteriorating transformer parts and components (such as radiators, gaskets, gauges, bushings, fans, pumps, and instrumentation) through major refurbishment or replacement prior to the end of the expected service life of the transformer. The Transformer Refurbishment program targets transformers that have not been scheduled for capital replacement programs.

The scope of the refurbishments is comprehensive and includes activities such as changing gaskets, refurbishment or replacement of transformer components, adding and upgrading transducers and monitoring devices, painting, and oil processing. Some refurbishments also include dry-out treatment, to reduce moisture in the transformer's internal paper insulation in order to preserve its useful life. These refurbishments are completed where it is cost-effective to do so. They allow the transformer to remain in-service through its expected service life while maintaining reliability.

In addition to transformer refurbishments, several smaller transformer programs are being implemented under this category to reduce the risks of equipment failure. These programs have been developed because of failure investigation findings or to align with current industry best practices. Examples of these activities include upgrading fall-arrest safety systems, installation of maintenance-free self-regenerating breathers, installation of under-load tap changer (ULTC) filtration systems, and the planned implementation of manufacturer recommended modifications to ULTCs.

Table 12 below sets out Hydro One's planned expenditures for this program for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 12 - Hydro One - Transformer Refurbishment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Transformer Refurbishment	2.6	2.3	1.7	3.1	3.0	4.5

The 2028 Test Year expenditure for Hydro One's Transformer Refurbishment is $4.5M. This is a $1.9M (73.1%) increase relative to 2023 actual expenditures and a $2M (77.2%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by transformer units deferred during the 2023-2027 period that were a lower priority for refurbishment given funding limits but, if left unaddressed, will reach end of life and/or deteriorate much faster than if refurbished.

2.2.3.4 POWER EQUIPMENT MAINTENANCE - BREAKER REFURBISHMENTS

Breaker refurbishments are required to address specific issues with some circuit breaker models (e.g., air blast, oil, gas-insulated switchgear, and sulfur hexafluoride (SF_6) circuit breakers) so as to allow those circuit breakers to reach their expected service lives. A significant portion of this program encompasses breaker refurbishment activities that resulted from past failures and corrective action plans developed during failure investigations. The majority of expenditures in this category are related to modifications and upgrades targeting oil, and SF_6 breakers as well as gas-insulated switchgear (GIS). Planned work focuses on mitigating reliability risks by performing time-based condition monitoring to track asset condition and then, based on asset condition, undertaking the necessary actions to ensure reliability for customers and the BES. The Breaker Refurbishment program also focuses on refurbishing GIS breakers and high-voltage breaker hydraulic drive mechanisms.

Table 13 below sets out Hydro One's planned expenditures for this program for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 13 - Hydro One - Breaker Refurbishment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Breaker Refurbishment	0.7	0.9	1.0	1.2	1.5	1.2

Hydro One's Breaker Refurbishment expenditure for the 2028 Test Year is $1.2M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the historical average for the 2023-2027 period.

The Test Year refurbishment expenditures are necessary to continue refurbishing poor-condition breakers to preserve their expected service life and reliability, as well as to mitigate the need for premature replacement.

2.2.3.5 POWER EQUIPMENT MAINTENANCE - OTHER MAINTENANCE AND INSPECTION PROGRAMS

Maintenance activities under this category include nuisance wildlife control, maintenance required for strategic spares, and miscellaneous maintenance as outlined below.

Nuisance wildlife control programs are in place to address the issues associated with equipment interruptions and customer outages resulting from wildlife entering Hydro One's transmission stations. The program involves installation of animal controls (such as cover-ups) and barriers (such as perimeter fence dig barriers) to limit the likelihood of an animal coming into contact with power equipment. Hydro One has found this program to be effective in mitigating delivery point interruptions caused by animal contact.

Strategic spares maintenance programs are in place to maintain the inventory of spare parts or components for transformers and circuit breakers that support the in-service fleet. The program includes the maintenance required to ensure that these components are available to enable timely response to system component failures and are maintained in a manner that does not void manufacturer warranties.

Other miscellaneous maintenance programs for power equipment include station asset assessment activities. These activities are important for ensuring equipment and customer reliability, as well as for managing equipment in a prudent and sustainable manner.

Table 14 below sets out Hydro One's planned expenditures for this program for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 14 - Hydro One - Other Maintenance and Inspection Programs OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Other Maintenance and Inspection Programs	1.9	2.2	2.6	2.6	2.6	2.9

Hydro One's 2028 Test Year expenditure for the Other Maintenance and Inspection Program is $2.9M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the historical average for the 2023-2027 period.

2.2.4 STATIONS SUSTAINMENT OM&A - ANCILLARY SYSTEMS MAINTENANCE

Ancillary systems are comprised of station service systems, high-pressure air systems, grounding systems, DC battery and charger systems, backup generators, and oil-processing facilities. These systems provide key services and operating support to various station components and protection systems and are required at all Hydro One transmission stations.

This program focuses on sustaining the performance of ancillary systems by dividing the work into the following three categories: (i) Preventive Maintenance; (ii) Corrective Maintenance; and (iii) Other Maintenance Programs. Table 15 shows Hydro One's planned expenditures for this program in the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each category.

Table 15 - Hydro One - Ancillary Systems Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	4.5	4.3	4.1	4.2	4.1	4.2
Corrective Maintenance	3.4	2.7	3.1	3.5	3.4	4.5
Other Maintenance Programs	1.4	1.2	1.0	1.5	1.5	1.8
Total	**9.4**	**8.2**	**8.3**	**9.2**	**8.9**	**10.5**

The 2028 Test Year expenditure for Hydro One's Ancillary Systems Maintenance is $10.5M. This is a $1.2M (12.9%) increase relative to 2023 actual expenditures and a $1.7M (19.9%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the need to repair deficiencies in station grounding systems, which are essential components of transmission stations that ensure public and employee safety.

2.2.4.1 ANCILLARY SYSTEMS MAINTENANCE - PREVENTIVE MAINTENANCE

The Preventive Maintenance program for Ancillary Systems is required to sustain the performance of ancillary equipment that supports the operation of protection systems and critical power equipment. Preventive maintenance activities include periodic testing and inspections to ensure that the equipment is in satisfactory condition and will operate reliably.

Oversight bodies, such as the Technical Standards and Safety Authority, IESO, Northeast Power Coordinating Council (NPCC), NERC, Ministry of Health, and the MOECP, impose various regulatory requirements and in some cases mandate specific inspection and testing cycles to which Hydro One must adhere.

Table 16 shows Hydro One's planned expenditures for this program in the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical years.

Table 16 - Hydro One - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	4.5	4.3	4.1	4.2	4.1	4.2

Hydro One's 2028 Test Year expenditures for the Ancillary Systems Preventive Maintenance is $4.2M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the historical average for the 2023-2027 period.

2.2.4.2 ANCILLARY SYSTEMS MAINTENANCE - CORRECTIVE MAINTENANCE

The Corrective Maintenance program for Ancillary Systems is required to repair ancillary equipment defects and return equipment condition and performance to an acceptable state. Corrective maintenance is a combination of planned and unplanned work, including emergency response. Corrective maintenance is required to address the risk of harm and/or damage to employee safety, public safety, system reliability, or the environment.

Table 17 shows Hydro One's planned expenditures for this program in the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 17 - Hydro One - Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Corrective Maintenance	3.4	2.7	3.1	3.5	3.4	4.5

Hydro One's 2028 Test Year expenditures for the Ancillary Systems Corrective Maintenance is $4.5M. This is a $1.1M (32.4%) increase relative to 2023 actual

expenditures and a $1.3M (39.8%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the need to repair deficiencies in station grounding systems, which are essential components of transmission stations that ensure public and employee safety.

2.2.4.3 ANCILLARY SYSTEMS MAINTENANCE - OTHER MAINTENANCE PROGRAMS

Other maintenance program activities include grounding studies and repairs, maintenance of Hydro One's oil storage and processing operation at its Central Maintenance Services facility.

This program also funds the payments for services at facilities shared with OPG and Bruce Power. Hydro One has several sites located within or adjacent to generating stations (hydraulic, thermal, and nuclear) that are owned and operated by OPG or Bruce Power and where services are purchased directly from the plant in order to maintain switchyard operations. These services include AC/DC station service and water and snow removal.

Table 18 sets out Hydro One's planned expenditures for this program in the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 18 - Hydro One - Other Maintenance Programs OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Other Maintenance Programs	1.4	1.2	1.0	1.5	1.5	1.8

Hydro One's 2028 Test Year expenditures for the Ancillary Systems Other Maintenance is $1.8M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the historical average for the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the need to address certain grounding system deficiencies. The grounding system is an essential component at a transmission station, as it ensures public and employee safety in the station by keeping all equipment at the same electrical potential and directing unwanted energy away from equipment and other connected metallic objects into the earth during electrical faults. Under this program, Hydro One inspects and repairs (where needed) grounding systems to ensure they are in good condition and workable order.

2.2.5 STATIONS SUSTAINMENT OM&A - PROTECTION, AUTOMATION AND TELECOM MAINTENANCE

Protection and automation assets are required to protect, control, and operate the transmission system. They also provide real-time operational data, control remote equipment, and capture detailed event records for post-event analysis. Power system telecom systems provide high-reliability and high-speed communications required for the protection, monitoring, and control of Hydro One’s transmission system.

Table 19 below sets out Hydro One's planned OM&A expenditures for protection, automation and telecom assets for the Test Year, along with the forecast and actual spending level for the Bridge and Historical Years.

Table 19 - Hydro One - Protection, Automation and Telecom OM&A ($M)[6]

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Protection and Automation	16.9	16.1	14.6	17.8	16.9	18.9
Telecom	30.1	32.6	35.2	36.5	37.8	44.7
Total	**47.0**	**48.7**	**49.8**	**54.3**	**54.7**	**63.6**

The 2028 Test Year expenditure for Hydro One's Protection, Automation and Telecom OM&A is $63.6M. This is a $16.6M (35.3%) increase relative to 2023 actual expenditures and a $12.7M (25.0%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by higher expenditures for Protection and Automation that are required to meet additional new and updated NERC and NPCC requirements, and higher expenditures for essential Power System Telecom Services, including the rising cost of contractual leased services.

2.2.5.1 STATIONS SUSTAINMENT OM&A - PROTECTION AND AUTOMATION

Protection and automation assets are required to protect, control, and operate the transmission system. The maintenance of these assets is required to sustain equipment performance and to comply with applicable NERC standards.

The protection and automation maintenance program is divided into three categories, discussed further below: (i) Preventive Maintenance, (ii) Corrective Maintenance, and (iii) Support Processes and Systems. Table 20 below sets out Hydro One's planned expenditures for the Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each of the three categories.

[6] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 20 - Hydro One - Protection and Automation OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	3.9	3.9	3.9	4.4	4.5	5.2
Corrective Maintenance	6.5	6.3	5.5	6.4	6.3	7.6
Support Processes and Systems	6.5	5.9	5.2	7.1	6.0	6.1
Total	**16.9**	**16.1**	**14.6**	**17.8**	**16.9**	**18.9**

The 2028 Test Year expenditure for Hydro One's Protection and Automation OM&A is $18.9M. This is a $2.0M (11.8%) increase relative to 2023 actual expenditures and a $2.4M (14.8%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is driven by two primary requirements: (1) completing the remaining BES Protection System preventive maintenance activities required under the phased implementation of NERC reliability standard PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), with the last implementation milestone coming due in 2028; and (2) clearing the deferred non-BES Protection System preventive maintenance activities to return those assets to their established maintenance cycles. These activities are required to manage compliance obligations, address accumulated maintenance risk, and support the reliable operation of Protection System assets.

Further details of the forecasted costs for each of the three Protection and Automation OM&A programs are discussed below.

2.2.5.2 PROTECTION AND AUTOMATION - PREVENTIVE MAINTENANCE

Preventive Maintenance involves routine testing of protection systems. Examples of such activities include relay re-verification, zone test trip, breaker trip coil testing, and special

protection system trip testing. Further details relating to the prescribed maintenance for protection system activities are provided in TSP Section 2.2.

Protection systems spend most of their service life in a stand-by or monitoring state, yet they must be relied upon to perform flawlessly within milliseconds of a fault inception or other abnormal system conditions. Routine, preventive testing is the only means to maintain a high degree of certainty that the system will operate correctly when called upon.

Maintenance performed on most Hydro One's protection-related assets is governed by NERC standards. The maintenance activities and testing frequencies for protection systems that are part of the BES are mandated by NERC reliability standard PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance). For the remaining portions of the system, the scope of testing and testing frequencies are determined in accordance with a risk evaluation for reliability, safety, and environmental impact, as per Hydro One standards.

Hydro One's planned expenditures for Preventive Maintenance OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 21 below.

Table 21 - Hydro One - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	3.9	3.9	3.9	4.4	4.5	5.2

Hydro One's Protection and Automation Preventive Maintenance expenditure for the 2028 Test Year is $5.2M. This is a $1.3M (33.3%) increase relative to 2023 actual expenditures and a $1.1M (26.2%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by:

- completing the remaining BES Protection System preventive maintenance activities required under the phased implementation of NERC reliability standard PRC-005-6 (Protection System, Automatic Reclosing, and Sudden Pressure Relaying Maintenance), with the last implementation milestone coming due in 2028; and
- clearing the deferred non-BES Protection System preventive maintenance activities to return those assets to their established maintenance cycles.

These activities are required to manage compliance obligations, address accumulated maintenance risk, and support the reliable operation of Protection System assets.

2.2.5.3 PROTECTION AND AUTOMATION - CORRECTIVE MAINTENANCE

All Protection and Automation assets experience a certain rate of failure during their normal operating life. Increased failure rates cause a reduction in overall system reliability. The Corrective Maintenance program allows Hydro One to restore system reliability by performing timely emergency repairs and remedying systemic protection equipment issues. These issues are usually discovered during the analysis of protection system misoperations and typically relate to design or manufacturing defects. If not corrected on time, these issues can impact other similar installations.

Once the failure of any portion of the protection system is detected, Operating Centre staff dispatch field personnel to resolve the issue and restore system reliability. If the problem is discovered during a preventive maintenance test, corrective action must be taken immediately to avoid adverse impacts to system reliability. The corrective action can be as minor as calibrating a relay or as major as replacing an existing relay with a new or refurbished one. The costs of these corrective actions are covered by this program.

As part of its obligation to comply with NERC requirements, Hydro One must analyze every BES protection system operation and correct those which are characterized as misoperations. When Hydro One determines that a misoperation is not an isolated case (e.g., it is a manufacturer defect that applies to multiple relays), Hydro One proactively

replaces or repairs protection system components to prevent widespread system issues. The costs of these planned corrective actions are also covered by this program.

Hydro One's planned expenditures for Corrective Maintenance OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 22 below.

Table 22 - Hydro One - Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Corrective Maintenance	6.5	6.3	5.5	6.4	6.3	7.6

Hydro One's Protection and Automation Corrective Maintenance expenditure for the 2028 Test Year is $7.6M. This is a $1.1M (16.9%) increase relative to 2023 actual expenditures and a $1.4M (22.6%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by costs required to perform (i) emergency corrective maintenance activities, (ii) corrective maintenance activities associated with those assets that are most critical to system reliability, safety, and environment, and (iii) corrective maintenance activities that are of higher priority due to compliance requirements under applicable NERC standards.

2.2.5.4 PROTECTION AND AUTOMATION - SUPPORT PROCESSES AND SYSTEMS

Hydro One maintains a set of support processes and systems that are needed to maintain protection and automation system assets. These systems are in place to manage relay settings, to control changes to relay settings and configurations, to keep records of system events, and to manage the inventory and re-seal schedule for revenue meters. The Support Processes and Systems program covers the costs associated with maintaining these systems.

In addition, this program provides funding for multiple activities that directly support system reliability and maintain Hydro One's compliance with mandatory NERC requirements. These activities include:

- Analyses of protection system operations;
- Tracking vendor advisories;
- Root-cause analysis of protection system component failures and mitigation actions;
- Managing protection and automation spare parts;
- Maintaining transmission metering assets; and
- Maintaining protection and automation asset data and information.

The proposed funding for these activities is necessary to ensure that Hydro One maintains its safety and reliability performance and complies with applicable NERC requirements. Hydro One's planned expenditures for Support Processes and Systems OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 23 below.

Table 23 - Hydro One - Support Processes and Systems OM&A ($M)

Description	Historical				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Support Processes and Systems	6.5	5.9	5.2	7.1	6.0	6.1

Hydro One's Support Processes and Systems expenditure for the 2028 Test Year is $6.1M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

2.2.5.5 STATIONS SUSTAINMENT OM&A - POWER SYSTEM TELECOM

Power System Telecom Services (PSTS) provide high-reliability, high-speed communications required for the protection, monitoring, control, and operation of Hydro One's transmission system in Ontario. Hydro One's Power System Telecom system consists of a fibre optic-based synchronous optical networking (SONET) transport network,

power-line carrier (PLC) systems, teleprotection terminal devices, microwave radio systems, high voltage protection (HVP) systems, provincial mobile radio system (PMRS), and associated auxiliary telecommunication equipment and infrastructure.

The Power System Telecom program is divided into three categories, discussed further below: (i) Preventive and Corrective Maintenance; (ii) Leased Telecommunication Circuits for PSTS; and (iii) Operation of PSTS. Table 24 below sets out Hydro One's planned expenditures for Power System Telecom OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each of these three categories.

Table 24 - Hydro One - Power System Telecom OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive and Corrective Maintenance	5.3	6.3	7.3	6.8	6.4	8.3
Leased Telecommunication Circuits for Power System Telecom Services	14.3	15.3	16.3	17.0	18.2	21.7
Operation of Power System Telecom Services	10.5	10.9	11.6	12.7	13.3	14.7
Total	**30.1**	**32.6**	**35.2**	**36.5**	**37.8**	**44.7**

The 2028 Test Year expenditure for Hydro One's Power System Telecom OM&A is $44.7M. This is a $14.6M (48.5%) increase relative to 2023 actual expenditures and a $10.3M (29.8%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the increasing cost of contractual leased services and the increasing cost of operation of Power System Telecom Services, and higher preventive and corrective maintenance expenditures. Further details of the forecasted costs for each of the three Power System Telecom OM&A programs are discussed below.

Hydro One's proposed expenditure for Telecom Preventive and Corrective Maintenance for the 2028 Test Year is $8.3M. This is $1.9M higher than the average annual expenditure over the 2023-2027 period of $6.4M. Under the Operation of Power System Telecom Services category, Hydro One receives coordinated network management, vendor management, real-time alarm-based monitoring, and system analysis services from Acronym Solutions Inc. (ASI), formerly Hydro One Telecom Inc.

In addition, the planned 2028 Test Year expenditure for Leased Telecommunication Circuits for Power System Telecom Services is $5.5M higher than the average annual expenditure over the 2023-2027 period. This program includes the cost of additional leased circuits and circuit capacity that are required for on-going deployment of new protection, control, and monitoring equipment to support Hydro One's power system. Leased circuit costs increase due to the increasing cost of contractual agreements and increasing number and capacity of leased circuits required.

2.2.5.6 POWER SYSTEM TELECOM - PREVENTIVE AND CORRECTIVE MAINTENANCE - POWER SYSTEM TELECOM

The Preventive and Corrective Maintenance program is required to sustain Hydro One's Power System Telecom systems for the safe and reliable operation of Hydro One's transmission system. Routine telecom maintenance requires field testing of telecom schemes and equipment to ensure that they are operating within expected parameters.

Telecom preventive maintenance involves the following activities:

1. Routine maintenance/re-verification;
2. Signal adequacy tests (SATs);
3. Radio communication tower visual/structural inspections;
4. Telecom battery/charger maintenance;
5. Auxiliary telecommunication equipment inspections; and
6. OPGW and all-dielectric self-supporting (ADSS) cable maintenance and inspections.

Timing intervals for telecom preventive maintenance are dependent on the technology and/or equipment used in the communications scheme, and on whether the telecom equipment directly interfaces with protection schemes included in the BES. Maintenance of telecom devices that are an integral part of protection schemes classified as BES elements is non-discretionary and requires annual compliance reporting, as per the NERC PRC-005 and NPCC Directory 8 regulatory standards.

The overall strategy for the preventive maintenance component of the program is to reduce replacement costs, corrective maintenance costs, and interruption of services while complying with regulatory and Hydro One maintenance requirements. Preventive maintenance is used to gauge the condition of the assets and to aid in the planning of asset replacements and technology upgrades.

Corrective maintenance performed on Power System Telecom assets consists of (i) planned corrective maintenance to rectify issues that were identified during preventive maintenance or to address failure events that do not have an immediate system impact, and (ii) emergency corrective maintenance to rectify issues that have already impacted system stability or will have an immediate impact on system stability if left unresolved.

The overall program strategy for the corrective maintenance component of the program is to ensure that Power System Telecom issues are corrected in a timely manner based on severity of the issue. Planned corrective maintenance prioritizes corrective actions based on the available budget and on identified issues to ensure that future system impacts are mitigated, while reducing future corrective maintenance costs. Emergency corrective maintenance ensures that the affected telecom components and services are restored to normal operating conditions as soon as possible.

As part of the overall Preventive and Corrective Maintenance program, Hydro One also maintains an adequate level of operational spare equipment to respond to corrective maintenance requirements and restore communication systems to normal operation within a timely manner, thereby minimizing potential reliability impact on the transmission system.

Hydro One's planned expenditures for Preventive and Corrective Maintenance OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 25 below:

Table 25 - Hydro One - Preventive and Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/Cast	2027 F/Cast	2028 F/cast
Preventive and Corrective Maintenance	5.3	6.3	7.3	6.8	6.4	8.3

The 2028 Test Year expenditure for Hydro One's Telecom Preventive and Corrective Maintenance is $8.3M. This is a $3M (56.6%) increase relative to 2023 actual expenditures and a $1.9M (29.3%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the increasing cost of maintenance, increasing cost of repairs, and additional maintenance required to meet NERC compliance requirements.

2.2.5.7 POWER SYSTEM TELECOM - LEASED TELECOM CIRCUITS

Hydro One leases carrier-based telecommunication circuits from third-party providers to support the telecommunication requirements for protection and control of the power system. This program covers the costs associated with leasing telecommunication services for power system protection and control, the provincial mobile radio system, and sites/space for provincial mobile radio base stations. To contain leasing costs for telecom circuits, Hydro One enters into long-term contracts where it is feasible to secure competitive pricing from third-party telecom service providers. Some telecommunications services covered by this program are tariffed, meaning the rates for those services are approved and regulated by the Canadian Radio-television Telecommunications Commission (CRTC).

Some of the protection systems at transmission stations depend on remote backup, automated electrical grounding, and sometimes operator intervention due to a lack of telecommunication facilities. To improve system reliability, new leased circuits are incorporated into protection schemes to help clear a fault within appropriate time frames. Hydro One's planned expenditures for Leased Telecommunication Circuits for Power System Telecom Services OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 26 below.

Table 26 - Hydro One - Leased Telecommunication Circuits OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Leased Telecommunication Circuits for Power System	14.3	15.3	16.3	17.0	18.2	21.7

Hydro One's Leased Telecommunication Circuits for Power System expenditure for the 2028 Test Year is $21.7M. Leased circuit costs increased due to the increasing cost of contractual agreements and increasing number and capacity of leased circuits required.

2.2.5.8 POWER SYSTEM TELECOM - OPERATION OF POWER SYSTEM TELECOM

This program covers the cost of labour for the monitoring, management, and operation of the telecom infrastructure and engineering technical support for Power System Telecom Services. These services are provided by the Integrated Telecom Management Center (ITMC) at Acronym Solutions Inc. (ASI), formerly Hydro One Telecom Inc. (HOT), under a Telecom Services Agreement with Hydro One.

ASI provides Hydro One with coordinated network management, vendor management, real-time alarm-based monitoring, and system analysis services. ASI also provides services related to maintaining and upgrading the Operating Support Systems, which consist of inventory management, network management, and other software systems used in the operation and management of Hydro One's telecommunication assets and services. The Operating Support Systems are vital to supporting the day-to-day ITMC

operational functions, including the updating of the inventory of the fibre-optic network, the management and updating of network alarms, the management of incidents (trouble tickets), and outage and change requests.

While Operating Support Systems upgrades will be addressed through capital programs, Operation of Power System Telecom Services OM&A includes spending to support enhancements to telecommunication systems to address key Operating Support Systems that no longer have adequate vendor support and are at the end of their service lives.

Hydro One's planned expenditures for Operation of Power Telecom Services OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 27 below.

Table 27 - Hydro One - Operation of Power Telecom Services OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Operation of Power System Telecom Services	10.5	10.9	11.6	12.7	13.3	14.7

Hydro One's Operation of Power System Telecom Services forecast expenditure for the 2028 Test Year is $14.7M. This is a $4.2M (40%) increase relative to 2023 actual expenditures and a $2.9M (24.6%) increase relative to the average annual expenditures over the 2023-2027 period.

The increase relative to the average annual expenditures over the 2023-2027 period is primarily driven by the increasing cost of contractual services required from Acronym Solutions Inc.

2.2.6 STATIONS SUSTAINMENT OM&A - SECURITY

Hydro One must comply with mandatory physical and cybersecurity standards intended to ensure the integrity and reliable operation of the Ontario Bulk Electricity System (BES)

and the interconnected North American grid. These requirements are established by the North American Electric Reliability Corporation (NERC) through its Critical Infrastructure Protection (CIP) standards.

NERC Security OM&A expenditures fund the ongoing maintenance, monitoring, testing, documentation, and audit readiness activities required to sustain compliance with these standards. These activities mitigate physical and cybersecurity risks to BES facilities, systems, and equipment. If these systems were to be compromised, it could adversely affect transmission system reliability.

A more detailed description of this program is in Exhibit E-04-04, Section 2.4.3.

Table 28 below sets out Hydro One's planned expenditures for NERC Security OM&A for the Test Year, along with its forecast and actual spending levels for the Bridge and Historical Years.

Table 28 - Hydro One - NERC Security OM&A ($M)

Description	Historical				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
NERC Security	18.0	20.9	23.8	23.0	22.5	11.7

Hydro One's NERC Security forecast expenditure for the 2028 Test Year is $11.7M. This is a $6.2M (35%) decrease relative to 2023 actual expenditures and a $9.9M (46%) decrease relative to the average annual expenditures over the 2023-2027 period.

While NERC Security expenditures within Transmission Sustainment OM&A appear lower in the 2028 Test Year, this decrease does not reflect a reduction in security activities or NERC security-related spending. Rather, it reflects the consolidation of the OT Infrastructure Sustainment Contract and Cyber Security Operations subprograms into common security programs, as they have evolved to support both Transmission and Distribution security needs. The expenditures for these subprograms and further

discussion of this consolidation can be found under General Security in exhibit E-04-04, Section 2.4.1.

2.2.7 STATIONS SUSTAINMENT OM&A - SITE INFRASTRUCTURE MAINTENANCE

Hydro One's site facilities and infrastructure systems are comprised of structural, building shell, roofing, HVAC, water and sewage management, fire protection and detection, elevators, interior fixtures, access roads, yard drainage, siteworks and fences at transmission stations. These systems provide infrastructure and support services to other station components, prevent unauthorized access, and make the station site functional for equipment and staff.

The Site Infrastructure Maintenance program is focused on the planned and corrective maintenance at transmission stations, to ensure that these site facilities and infrastructure systems remain safe and in compliance with regulatory requirements – which principally include the Ontario Building Code, Ontario Protection and Prevention Act, Environmental Protection Act, Technical Standards and Safety Act, and the Occupational Health and Safety Act. As detailed below, Hydro One proposes to address both needed corrective and preventive maintenance.

The program is extensively driven by the assessment of data collected, unplanned work, corporate standards, municipal by-laws, regulatory requirements and provincial legislation. The program is divided into the following three categories: (i) Facilities/Infrastructure Maintenance, (ii) Grounds Maintenance, and (iii) Site Perimeter Maintenance.

Table 29 below sets out Hydro One's planned expenditures for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 29 - Hydro One - Site Infrastructure Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Facilities/ Infrastructure Maintenance	19.1	18.5	17.9	17.1	16.5	28.4
Grounds Maintenance	2.5	2.9	2.8	2.8	2.7	3.0
Site Perimeter Maintenance	4.7	5.2	5.2	5.0	4.9	5.5
Total	**26.4**	**26.6**	**25.9**	**24.9**	**24.1**	**36.9**

The 2028 Test Year expenditure for Hydro One's Site Infrastructure Maintenance is $36.9M. This is a $10.5M (39.8%) increase relative to 2023 actual expenditures and a $11.3M (44.3%) increase relative to the average annual expenditures over the 2023-2027 rate period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by increased corrective and preventive maintenance activities. Corrective maintenance addresses deficiencies in station building infrastructure, including break-fix repairs to critical components such as leaking roofs and drainage/sump pump equipment, that help protect Hydro One's electrical equipment within power system buildings. Preventive maintenance includes servicing critical building components such as HVAC systems and building shells, to extend their service life.

This increase is needed to address two objectives. The first is corrective maintenance, to remedy deficiencies in station building infrastructure, such as leaking roofs and drainage/sump pump equipment, that pose a risk to reliability and protection of electrical equipment housed in power system buildings. Deferrals of needed corrective maintenance increase the risk of asset deterioration, reduce maintenance effectiveness, and elevate the likelihood of more costly break-fix repairs.

The second is preventive maintenance, to service critical and expensive building components such as HVAC systems and the building shell and extend their service life. Hydro One manages a portfolio of 1,085 buildings at 371 transmission station sites across

Ontario. These buildings primarily house power system equipment and perform functions that are critical to maintaining reliable and safe transmission of electricity. Hydro One's Building Condition Assessment program confirms that approximately 36% of transmission station buildings are now in poor condition, and are forecast to increase to over 55% by 2030 without intervention.[7] As these components continue to age, failures occur more frequently, increasing reactive break-fix work and limiting Hydro One's ability to undertake preventive maintenance activities. Resuming an adequate level of preventive maintenance will help address this cycle, and in combination with the planned 2028–2032 capital investments, these activities are expected to reduce the volume of assets in poor condition and lower reactive maintenance requirements over the longer term.

2.2.7.1 SITE INFRASTRUCTURE MAINTENANCE - FACILITIES AND INFRASTRUCTURE

This program consists of corrective maintenance, preventive maintenance, scheduled maintenance, and administrative and operational expenses required to maintain transmission station facilities and associated infrastructure. These activities maintain the functionality, safety, and reliability of station buildings and site infrastructure, preserve the useful life of transmission building components, and provide the condition information necessary to identify and prioritize future investments.

Over the 2023-2025 period, the largest operating expense spending categories at transmission stations were Building Repair and Maintenance, HVAC Maintenance, Snow Removal, Janitorial, Inspections and Assessments, and Electricity/Utility Bills.[8]

The day-to-day operation and maintenance of sites, including janitorial services, snow clearing and removal, and grass cutting, is managed through FRE's Outsourced Service Provider (OSP). Generally, an OSP can negotiate lower costs and improved service levels through their existing relationships with vendors across Ontario. Using an OSP allows

[7] GSP Section 4.11 G-GP-04, p. 8, Table 3 and p. 51

[8] Building Repair and Maintenance is part of corrective maintenance. HVAC Maintenance is part of preventive maintenance. Snow Removal, Janitorial, Inspections and Assessments are part of scheduled maintenance. Electricity/Utility Bills are part of operational expenses.

Hydro One to unlock preferred pricing through bulk contracts, either through savings for the same level of service or lower prices for increased levels of service.

Utility bills for electricity, water, wastewater and waste removal are part of day-to-day operations costs for all staffed and unstaffed facilities.

Information on the condition of station sites and buildings is collected through regular inspections and assessments, including during maintenance work and trouble-call responses. Contracted inspections and asset surveys are also conducted. The condition assessments and related data are crucial to FRE's data-driven decision-making framework.

Table 30 below sets out Hydro One's planned expenditures for Facilities and Infrastructure Maintenance OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 30 - Hydro One - Facilities and Infrastructure Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Facilities/ Infrastructure Maintenance	19.1	18.5	17.9	17.1	16.5	28.4

Hydro One's Facilities/Infrastructure Maintenance expenditure for the 2028 Test Year is $28.4M. This is a $9.3M (48.7%) increase relative to 2023 actual expenditures and a $10.6M (59.4%) increase relative to the average annual expenditures over the 2023-2027 period.

The preventive maintenance program for transmission station facilities and infrastructure addresses a wide variety of activities, such as HVAC maintenance, water system maintenance and testing, and sitework maintenance. The preventive maintenance program is currently underfunded relative to need due to the large number of transmission

station facilities and infrastructure components in poor condition requiring break-fix emergencies or urgent repairs. During the 2023-2025 period, Hydro One experienced increasing corrective maintenance demands as a growing proportion of building components reached poor condition or condition-adjusted end-of-life. To respond to these urgent repair requirements within available funding, Hydro One reduced the scope of certain preventive maintenance programs, including HVAC maintenance and other recurring lifecycle-based maintenance activities.

In the transmission station portfolio, about 55% of transmission station buildings are forecasted to deteriorate to a poor condition state within 5 years, based on results from Hydro One's Building Condition Assessment (BCA) program.[9] The growing number of transmission building components expected to reach their condition-adjusted end-of-life contributes to the elevated investment need for the 2028-2032 rate period.

Poor condition components have a higher likelihood of failure and consequentially result in corrective break-fix expenses or reactive repairs. These unplanned expenses reduce the amount of funding available for preventive maintenance – the regular investments which seek to extend the serviceable life of existing components by keeping them in a state-of-good-repair. Therefore, assets reach poor condition and end-of-serviceable life sooner than planned, and the cycle continues.

The proposed increase in Facilities and Infrastructure Maintenance funding is intended to reverse this trend by restoring preventive maintenance programs while continuing to address elevated corrective maintenance requirements.

Capital investments over the 2028-2032 period will reduce the amount of assets in poor condition and are expected to reduce the corrective maintenance requirements over the longer term. Reduced spending on corrective maintenance would enable Hydro One to allocate additional funding to preventive maintenance.

[9] GSP Section 4.11 G-GP-04, Section 1.0 Overview

2.2.7.2 SITE INFRASTRUCTURE MAINTENANCE - GROUNDS MAINTENANCE

The Grounds Maintenance program funds a number of activities, including the application of herbicides to control weeds and vegetation inside Hydro One's transmission stations. Weed and vegetation control is required to keep step and touch voltages at safe levels for workers who enter the station. Grounds maintenance also includes snow removal, grass cutting, clean-up, and general maintenance that may be required for site drainage and grading.

Table 31 below sets out Hydro One's planned expenditures for Grounds Maintenance OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 31 - Hydro One - Grounds Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Grounds Maintenance	2.5	2.9	2.8	2.8	2.7	3.0

Hydro One's Grounds Maintenance expenditure for the 2028 Test Year is $3.0M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

2.2.7.3 SITE INFRASTRUCTURE MAINTENANCE - SITE PERIMETER

The Site Perimeter Maintenance program includes preventive and corrective maintenance at station perimeters, with measures taken to keep animals out of stations and reduce the likelihood of power interruptions due to animal contacts. The activities under this program complement Hydro One's broader corporate security initiatives aimed at safeguarding transmission assets to ensure public and employee safety and to maintain equipment and system reliability.

Table 32 below sets out Hydro One's planned expenditures for Site Perimeter Maintenance OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 32 - Hydro One - Site Perimeter Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Site Perimeter Maintenance	4.7	5.2	5.2	5.0	4.9	5.5

Hydro One's Site Perimeter Maintenance expenditure for the 2028 Test Year is $5.5M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

3.0 LINES SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide further details regarding Lines Sustainment categories; the respective programs and sub-programs; and Test Year expenditures and variance analysis.

The high-voltage power lines in Hydro One's transmission network are categorized as either lines that form part the BES or area supply lines. Power lines which form part of the BES typically connect major generation facilities with transmission stations and often cover long distances, while area supply lines serve a local region.

Hydro One's transmission lines primarily operate at voltages of 500 kV, 230 kV and 115 kV, with minor lengths operating at 345 kV. Hydro One's transmission system consists of approximately 29,000 circuit km of overhead transmission lines located on about 81,500 hectares of rights-of-way and 279 circuit-km of underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shield wire, insulators, lightning arrestors,

hardware, switches, and grounding systems. Underground transmission line components include cables, terminations, oil pressure systems, and grounding systems. The underground transmission lines are generally located in large urban centres.

Lines Sustainment OM&A funding covers expenditures required to maintain existing overhead and underground transmission line assets. Hydro One manages the Lines Sustainment OM&A program by dividing the program into the following three categories:

1. Vegetation Management, which ensures that vegetation clearances to energized equipment are maintained. This includes brush control, line clearing, property owner notifications, annual vegetation patrol, demand (unplanned) maintenance, Virtual Patrols, and grounds maintenance.

2. Overhead Lines Maintenance, which focuses on inspections and condition assessments of overhead lines components to identify defects and poor-condition assets, planned corrective work to replace and repair minor components, and demand (unplanned) maintenance to respond to emergency situations.

3. Underground Cable Maintenance, which focuses on condition assessment through inspection, testing, analysis, and diagnostics of the main cable and ancillary equipment (accessories) used to support cable operation and associated corrective maintenance.

3.1 HYDRO ONE - LINES SUSTAINMENT OM&A

Hydro One's planned expenditures for Lines Sustainment OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 33 below for each of the categories discussed above.

Table 33 - Hydro One - Lines Sustainment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Vegetation Management	46.8	41.6	30.8	36.0	36.7	68.4
Overhead Lines Maintenance	14.3	14.2	10.4	14.4	14.1	22.2
Underground Cable Maintenance	6.8	6.5	6.2	4.8	4.7	7.8
Total	**67.9**	**62.3**	**47.4**	**55.2**	**55.5**	**98.4**

The 2028 Test Year expenditure for Hydro One's Transmission Lines Sustainment is $98.4M. This is a $30.5M (44.9%) increase relative to 2023 actual expenditures and a $40.7M (70.7%) increase relative to the average annual expenditures over the 2023-2027 period.

The increase in Test Year expenditures compared to the 2023-2027 forecast period is primarily driven by (i) the increased pace of asset condition assessments required to partially address the growing quantity of assets that require condition assessment, (ii) an increase in demand and planned defect corrective work, each of which forms part of the Overhead Lines Maintenance program, and (iii) higher volume and costs due to previously deferred vegetation maintenance.

This work is necessary as part of Hydro One's asset management approach and to maintain compliance with applicable NERC and NPCC reliability standards. Hydro One does not run its transmission assets to failure given their criticality to the integrity of the transmission system and the reliability, safety, and environmental impacts associated with their failure. Instead, Hydro One's asset management approach relies on sustaining assets based on condition, and maintenance and condition assessments must be performed on time in order to identify potential defects and poor-condition assets. Failure to do so increases the risk of outages caused by component failures that might have been identified during these activities. In addition, Hydro One's transmission system is subject to NERC and NPCC reliability standards, discussed further below, which require

maintenance and condition assessments to be performed at certain intervals and in certain circumstances.

The sections below provide more detailed program descriptions along with the planned Test Year expenditures (and variances where applicable) for each of the Lines OM&A programs.

3.2 VEGETATION MANAGEMENT OM&A - PROGRAM DETAILS

The strip of land that is occupied by a transmission line is referred to as a right-of-way (ROW) or a corridor. Hydro One's in-service ROWs cover an area of approximately 80,000 hectares and support Hydro One's 115 kV, 230 kV, 345 kV, and 500 kV circuits.

Hydro One's 230kV, 345kV, and 500kV circuits form part of the Bulk Electric System and are therefore subject to NERC's FAC-003 Transmission Vegetation Management standards. These require Hydro One to maintain the reliability of its transmission systems by preventing outages from vegetation located on transmission ROWs, minimizing outages from vegetation located adjacent to ROWs, and maintaining clearances between transmission lines and vegetation on and along transmission ROWs. To ensure system reliability and compliance with NERC's FAC-003, the Vegetation Management program is responsible for maintaining the clearance distance between the energized equipment and the vegetation located on and adjacent to all of these ROWs.

The Vegetation Management program consists of the following eight categories: (i) brush control, (ii) line clearing, (iii) condition patrol, (iv) virtual patrol, (v) property owner notifications, (vi) annual vegetation patrol, (vii) demand maintenance, and (viii) grounds maintenance.

Table 34 below sets out Hydro One's planned expenditures for Vegetation Management OM&A in the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each of these seven categories.

Table 34 - Hydro One - Vegetation Management OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Brush Control	29.1	25.6	17.9	18.9	19.3	39.7
Line Clearing	7.2	6.3	5.1	6.1	6.3	13.0
Condition Patrol	2.0	1.8	3.7	0.2	0.2	0.2
Virtual Patrol	0.0	0.0	0.0	4.7	4.2	6.4
Property Owner Notifications	2.4	2.1	0.9	1.9	1.9	2.4
Annual Vegetation Patrol	0.8	0.6	0.0	0.1	0.7	0.7
Demand Maintenance	3.5	3.1	0.9	2.0	2.0	3.4
Grounds Maintenance	1.8	2.3	2.4	2.1	2.2	2.5
Total	**46.8**	**41.6**	**30.8**	**36.0**	**36.7**	**68.4**

The 2028 Test Year expenditure for Hydro One's Vegetation Management OM&A is $68.4M. This is a $21.6M (46.2%) increase relative to 2023 actual expenditures and a $30M (78.2%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the need to complete previously deferred work, maintain compliance with NERC FAC-003 regulatory requirements and to support necessary vegetation maintenance activities across key right-of-way corridors, ensuring the continued safe and reliable operation of the transmission system.

3.2.1 VEGETATION MANAGEMENT OM&A - BRUSH CONTROL

Brush Control maintenance involves managing vegetation growth to ensure adequate standing clearance to overhead conductors necessary to preserve system performance and reliability. This is accomplished through selective application of herbicides and manual and mechanical brush cutting.

Hydro One's planned expenditures for Brush Control OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 35 below.

Table 35 - Hydro One - Brush Control OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Brush Control	29.1	25.6	17.9	18.9	19.3	39.7

The 2028 Test Year expenditure for Hydro One's Brush Control is $39.7M. This is a $10.6M (36.4%) increase relative to 2023 actual expenditures and a $17.5M (79.2%) increase relative to the average annual expenditures over the 2023-2027 period.

To manage expenditures during the 2023-2027 period, Hydro One prioritized brush control activities on NERC-applicable transmission circuits and deferred maintenance on portions of its 115 kV network. While this approach maintained compliance with regulatory obligations and focused resources on the highest consequence facilities, the deferred 115 kV corridors are a significant vegetation management concern requiring accelerated intervention.

Recent vegetation patrols, inspections, and LiDAR-based assessments as discussed in the virtual patrol section below have provided increased visibility into vegetation risk across the transmission network and confirmed the consequences of deferred maintenance. Deferred work consistently ranked among those with the highest concentrations of urgent vegetation defects identified during 2024 and 2025 patrols and inspections. Although off-cycle projects accounted for approximately 13% of Hydro One's ROW vegetation program in 2025, they represented a disproportionate share of urgent defects requiring immediate mitigation. Approximately 28% of urgent vegetation defects are associated with ROWs that are already one year beyond their target maintenance cycle, while a further 26% occurs on ROWs where maintenance is currently due.

Deferred work has a higher cost to complete due to increased growth and vegetation volume requiring more effort to address and may require additional patrols and Demand Maintenance work prior to scheduled maintenance.

The proposed increase in Brush Control funding will enable Hydro One to address the deferred 115 kV work, restore these corridors to their intended maintenance cycles, and reduce the growing volume of urgent vegetation defects requiring reactive intervention, and support the elimination of the accumulated deferred work over the next rate period.

The funding will increase Brush Control activity from approximately 6,000 hectares annually in 2026 and 2027, following approximately 6,700 hectares completed in 2025, to roughly 15,000 hectares per year beginning in 2028, supporting a sustainable, risk-based vegetation management program.

This increase is expected to reduce vegetation-related outage risk, improve system reliability, and avoid the escalating costs associated with continued deferrals.

3.2.2 VEGETATION MANAGEMENT OM&A - LINE CLEARING

Line Clearing maintenance involves the trimming and removal of trees, including danger trees, that do not meet Hydro One's standards along the edge of or adjacent to transmission ROWs. This work is necessary to maintain Hydro One's standing and falling clearances to the energized conductor and other transmission line equipment.

Hydro One's planned expenditures for Line Clearing OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 36 below.

Table 36 - Hydro One - Line Clearing OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Line Clearing	7.2	6.3	5.1	6.1	6.3	13.0

The 2028 Test Year expenditure for Hydro One's Line Clearing is $13M. This is a $5.8M (80.6%) increase relative to 2023 actual expenditures and a $6.8M (109.7%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed increase in the 2028 Test Year expenditure level relative to the average annual expenditures over the 2023-2027 period is primarily driven by the need to address vegetation defects, such as danger trees that may fall onto overhead lines and impact system reliability, and deferred Line Clearing work, which was deferred to manage funding levels. This may require additional patrols and Demand Maintenance work, including deferred right-of-way widening activities on narrow corridors that do not meet Hydro One's current clearance standards. The proposed expenditures are expected to help address deferred vegetation maintenance activities identified through recent patrols and LiDAR assessments; restore affected corridors toward their intended maintenance cycles and reduce future reliability, compliance, and reactive maintenance risks; and continue to support compliance with NERC FAC-003 regulatory requirements. Where possible, Hydro One conducts line clearing and brush control along the same or adjacent ROWs in the same year, thereby achieving efficiencies.

The requested funding increase will support the planned ramp-up of Line Clearing activities from approximately 2,294 km per year in 2026 and 2027 to approximately 4,712 km annually commencing in 2028. This additional funding is critical to addressing deferred work, restoring maintenance cycles to target levels, and eliminating the accumulated deferred work.

3.2.3 VEGETATION MANAGEMENT OM&A - CONDITION PATROL

Condition Patrol is a mid-cycle inspection to identify and mitigate any danger trees or vegetation that will encroach upon Hydro One's standing and falling clearances before the next scheduled line clearing or brush control maintenance.

Hydro One's planned expenditures for Condition Patrol OM&A for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 37 below.

Table 37 - Hydro One - Condition Patrol OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Condition Patrol	2.0	1.8	3.7	0.2	0.2	0.2

Hydro One's Condition Patrol expenditure for the 2028 Test Year is $0.2M, a $1.8M decrease from 2023 actuals and a $1.4M decrease from the average of the prior 2023-2027 rate period.

The decrease relative to the average annual expenditures over the 2023-2027 period is primarily due to the pausing and phasing out of this inspection program as Hydro One transitions to technology enabled, remote sensing and virtual patrol alternatives as explained in TSP Section 2.2.

3.2.4 VEGETATION MANAGEMENT OM&A - VIRTUAL PATROL

Hydro One uses LiDAR-based Virtual Patrols to enhance vegetation risk identification, support data driven vegetation management, and meet applicable vegetation inspection requirements. Following a successful pilot, Virtual Patrols using LiDAR have been integrated into Hydro One's annual vegetation management program, replacing traditional ground and helicopter patrols for approximately 50% of the network annually. This approach provides full network coverage over a two-year cycle while enhancing visibility of vegetation risks and supporting data-driven vegetation management.

Each year, LiDAR data is collected through aerial flights across the network to support the Virtual Patrol program. The data is utilized to identify vegetation that is encroaching upon Hydro One's standing and falling clearance distances and to identify trees that may pose a danger to the operation or safety of Hydro One lines. LiDAR data and collected imagery and analytics provide immediate risk reports, a comprehensive vegetation defect inventory, and enhanced information to support vegetation assessment, analysis, and work planning.

In accordance with NERC FAC-003, Hydro One is required to annually inspect all applicable circuits and circuits operating at 230 kV or greater. For NERC-applicable circuits receiving a Virtual Patrol in a given year, the patrol is used to satisfy annual inspection requirements.

Hydro One's vegetation inspection strategy combines LiDAR-based Virtual Patrols and Annual Vegetation Patrols to optimize vegetation risk identification, prioritization, and work planning. Approximately half of the network is assessed using LiDAR-based Virtual Patrols, which provide high-quality imagery and detailed vegetation data to support data-driven analysis, risk assessment, and work prioritization. The remaining portions are inspected through Annual Vegetation Patrols, enabling qualified forestry professionals to identify tree health concerns, structural defects, and potential fall-in hazards that may not be as readily identifiable through LiDAR analysis alone. This approach meets NERC FAC-003 requirements while enabling data-driven maintenance decisions.

Hydro One's planned expenditures for Virtual Patrol OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 38 below.

Table 38 - Hydro One - Virtual Patrol OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Annual Virtual Patrol	0.0	0.0	0.0	4.7	4.2	6.4

Hydro One's Virtual Patrol expenditure for the 2028 Test Year is $6.4M. As the Virtual Patrol program was established as a standalone AR in 2026, no expenditures were recorded under this program in the years prior to 2026. Accordingly, this represents a $6.4M increase relative to 2023 actual expenditures and a $4.6M increase relative to the average annual expenditures over the 2023-2027 period.

3.2.5 VEGETATION MANAGEMENT OM&A - PROPERTY OWNER NOTIFICATIONS

Property owner notifications are required before the execution of ROW vegetation maintenance. They consist of Hydro One contacting all required adjacent property owners to communicate maintenance plans, obtain approval for access onto private property, and acquire permission for the use of any herbicides to be applied during maintenance. Hydro One also engages with other external stakeholders, such as government agencies, municipal officials, and special interest groups as needed. Notifications are particularly important in urban areas where a significant number of vegetation encroachments require removal.

Hydro One’s planned expenditures for Property Owner Notifications OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 39 below.

Table 39 - Hydro One - Property Owner Notifications OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Property Owner Notifications	2.4	2.1	0.9	1.9	1.9	2.4

Hydro One's Property Owner Notification expenditure for the 2028 Test Year is $2.4M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

3.2.6 VEGETATION MANAGEMENT OM&A - ANNUAL VEGETATION PATROL

An annual vegetation patrol is conducted by air or ground and is used to identify vegetation that is encroaching upon Hydro One's standing and falling clearance distances and identify trees that may cause a danger to the operation or safety on Hydro One lines. In accordance with NERC FAC-003, Hydro One is required to annually inspect all its circuits operating at 230 kV or more. This patrol is conducted for NERC-applicable circuits not receiving Line Clearing or Virtual Patrol in the current calendar year.

Hydro One's planned expenditures for Annual Vegetation Patrol OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 40 below.

Table 40 - Hydro One - Annual Vegetation Patrol OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Annual Vegetation Patrol	0.8	0.6	0.0	0.1	0.7	0.7

Hydro One's Annual Vegetation Patrol expenditure for the 2028 Test Year is $0.7M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

3.2.7 VEGETATION MANAGEMENT OM&A - DEMAND MAINTENANCE

Demand Maintenance is an unplanned and corrective program which addresses vegetation issues that cannot wait until the next Line Clearing or Brush Control maintenance. Encroachments mitigated as part of this program are typically identified through Virtual Patrols or Annual Vegetation Patrols, but can also be initiated by other Hydro One business units, members of the public, municipalities, government agencies, etc.

Hydro One's planned expenditures for Vegetation Management Demand Maintenance OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided in Table 41 below.

Table 41 - Hydro One - Demand Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Demand Maintenance	3.5	3.1	0.9	2.0	2.0	3.4

Hydro One's Demand Maintenance expenditure for the 2028 Test Year is $3.4M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

The proposed 2028 Test Year forecast reflects the reactive nature of Demand Maintenance activities, which vary annually based on the volume of identified vegetation defects. The forecast is generally consistent with the average annual expenditures over the 2023-2027 period. It also reflects the anticipated impacts of deferred Line Clearing and Brush Control maintenance, which may result in an increased number of vegetation defects requiring corrective action. Furthermore, enhanced defect detection through LiDAR inspections is expected to increase the identification of vegetation-related issues requiring remediation.

3.2.8 VEGETATION MANAGEMENT OM&A - GROUNDS MAINTENANCE

Grounds maintenance includes grass cutting, snow removal, garbage clean-up, and repair of access barriers and fences on Hydro One's urban ROWs. The work is required to comply with local by-laws. It comprises both planned and demand components: planned work includes grass cutting and snow removal, which remains steady, while demand work fluctuates depending on clean-up or repair work that arises.

Table 42 below sets out Hydro One's planned expenditures for Grounds Maintenance OM&A for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, are provided.

Table 42 - Hydro One - Grounds Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Grounds Maintenance	1.8	2.3	2.4	2.1	2.2	2.5

Hydro One's Grounds Maintenance expenditure for the 2028 Test Year is $2.5M. The 2028 Test Year forecast is generally in line with the 2023 actual expenditures and the average annual expenditures for the 2023-2027 rate period.

3.3 OVERHEAD LINES MAINTENANCE OM&A - PROGRAM DETAILS

The Overhead Lines Maintenance program is required to maintain the reliability of transmission lines, address safety issues, and ensure the long-term economic viability of the overhead lines system. The program includes activities such as overhead lines inspections to identify defects, component condition assessments to identify poor-condition assets that will require replacement, planned corrective maintenance to replace and repair minor components, and demand maintenance to respond to emergency and high-priority situations. The gathering of asset condition information enables Hydro One to allocate funding based on priority to maximize the life of the line assets and to maintain asset performance. The program also provides for repair or replacement of defective equipment and components.

The Overhead Lines Maintenance program is divided into the following three activities: (i) Preventive Maintenance and Asset Assessment, (ii) Demand Maintenance, and (iii) Planned Corrective Maintenance. Table 43 below sets out Hydro One's planned Overhead Lines Maintenance expenditures in the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each category of activities.

Table 43 - Hydro One - Overhead Lines Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance and Asset Assessment	6.5	6.0	4.0	7.1	6.9	12.0
Demand Maintenance	5.8	6.3	3.8	3.4	3.3	3.5
Planned Corrective Maintenance	2.0	1.8	2.6	3.9	3.8	6.7
Total	**14.3**	**14.2**	**10.4**	**14.4**	**14.1**	**22.2**

The 2028 Test Year expenditure for Hydro One's Overhead Lines Maintenance is $22.2M. This is a $7.9M (55.2%) increase relative to 2023 actual expenditures and an $8.7M (64.7%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the following factors: (1) resumption of the execution of all Preventive Maintenance activities on cycle; (2) performing all required Asset Assessments as determined by Hydro One's Asset Strategy, while addressing deferrals from the 2023-2027 period, which have increased the number of assets with unknown condition; and, (3) addressing the deferred Low and Medium Priority defects resulting from postponed work during 2023-2027 to manage within funding limits.

3.3.1 OVERHEAD LINES MAINTENANCE OM&A - PREVENTIVE MAINTENANCE AND ASSET CONDITION ASSESSMENT

The Overhead Lines Maintenance program encompasses cyclical and non-cyclical maintenance activities. Cyclical maintenance activities include helicopter patrols/inspections and foot patrols to identify major defects on transmission line components, thermographic patrols to identify defective transmission line components using infrared cameras, switch maintenance to inspect and maintain switch components, and insulator washing to address salt contamination on selected transmission structures near urban highway and road crossings.

Non-cyclical activities are mainly asset condition assessments, which include climbing inspections to inspect structures in no-fly regions; conductor and shield-wire assessments using the Kinectrics LineVue tool, typically on aluminum conductor steel-reinforced (ACSR) conductors greater than 50 years of age and galvanized steel shield wires greater than 25 years of age; wood pole assessments to inspect the condition of the pole, typically on wood poles greater than 25 years of age; and steel structure assessments to evaluate the remaining protective zinc layer in heavy corrosion zones. Further information on these activities can be found in TSP Section 2.2.

In 2020, Hydro One undertook a review of its Preventive Maintenance and Asset Condition Assessment activities and optimized them to account for age of circuits, type of structure, and the efficiency of each patrol type. This change has contributed positively to Hydro One's ability to maintain consistent levels of reliability, despite deferrals on both OM&A and Capital programs and projects.

Hydro One performs testing to empirically establish the condition of its conductors, in particular through Kinectrics LineVue scans, laboratory testing, or a combination of both. These assessments enable Hydro One to verify conductor condition and safely operate conductors that remain in good condition beyond their expected service life, thereby avoiding unnecessary replacement.

LineVue scans and short sample testing provide an initial assessment that, in most cases, is sufficient to categorize a conductor as being in good, fair, or poor condition and determine whether replacement is warranted. Based on test results, the conductor will be scheduled for follow-up assessments in 5 to 15 years depending on the determined level of deterioration, or it will be planned for replacement if it is clearly identified as being in poor condition. Where testing indicates deterioration but does not conclusively establish poor condition, Hydro One undertakes more comprehensive short- or long-conductor sample testing to confirm asset condition and ensure that replacement is targeted only to conductors that require it.

Table 44 below sets out Hydro One's planned Preventive Maintenance and Asset Condition Assessment OM&A expenditures for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 44 - Hydro One - Preventive Maintenance and Asset Assessment OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance and Asset Assessment	6.5	6.0	4.0	7.1	6.9	12.0

The 2028 Test Year expenditure for Hydro One's Overhead Lines Preventive Maintenance and Asset Assessment is $12M. This is a $5.5M (84.6%) increase relative to 2023 actual expenditures and a $5.9M (96.7%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by the resumption of all Preventive Maintenance activities on their prescribed cycles and the completion of Asset Assessments that were deferred during the 2023-2027 period. For example, foot, helicopter and thermovision patrols were reduced to approximately 50% of normal levels. This has doubled the interval between inspections for affected circuits, resulting in nearly half of the transmission system not being inspected as scheduled and creating a greater risk of missed defects.

To resume the aforementioned patrols, Hydro One must complete an additional 12,100 units per year, totaling $2.8M. Similarly, many condition assessments were reduced or eliminated in some years. Not knowing the condition of transmission line components such as U-bolt hardware, insulators, wood poles, steel structures, conductors, and shield wires can increase safety and reliability risks over time. As a result, the planned expenditure in 2028 for asset condition assessments is required to help mitigate the risks introduced by

historical funding levels. Hydro One must complete an additional 1,347 units per year need, totaling $1.6M.

3.3.2 OVERHEAD LINES MAINTENANCE OM&A - DEMAND MAINTENANCE

Demand maintenance is needed to respond to emergencies and to restore power as soon as possible. This program includes activities such as unplanned data collection, emergency component repair, and trouble-call response. This program also addresses problems identified during line patrols that need a near-term response to prevent a potential outage or to address a serious safety issue.

Table 45 sets out Hydro One's planned overhead lines Demand Maintenance OM&A expenditures for the Test year, along with its forecast and actual spending levels for the Bridge and Historical Years.

Table 45 - Hydro One - Demand Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Demand Maintenance	5.8	6.3	3.8	3.4	3.3	3.5

The 2028 Test Year expenditure for Hydro One's Overhead Lines Demand Maintenance is $3.5M. This is a $2.3M (39.7%) decrease relative to 2023 actual expenditures and a $1.0M (22.6%) decrease relative to the average annual expenditures over the 2023-2027 period.

Hydro One determined its 2028 Test Year expenditures for this program based on historical actual expenditures, excluding unusual events such large storms, wildfires or unexpected major defects.

The decrease in forecast expenditures relative to earlier years in the 2023-2027 period is primarily due to Hydro One shifting its medium priority demand work from the Demand Maintenance Program to the Planned Corrective Maintenance program. This change

reflects a reallocation of work scope between programs rather than a reduction in the underlying maintenance need.

3.3.3 OVERHEAD LINES MAINTENANCE OM&A - PLANNED CORRECTIVE MAINTENANCE

Planned corrective maintenance and projects include minor corrective work and technical support to resolve reliability and safety problems with transmission line assets. The planned corrective maintenance activities and projects are developed using the data collected during patrols and asset assessment activities, as well as information about equipment reliability performance.

Planned corrective maintenance addresses multiple line components, including defective ground wire connections, missing or broken safety signs and nomenclature signs, U-bolt hardware that supports the insulator strings and conductors, and the replacement of dampers that limit conductor vibration.

Table 46 sets out Hydro One's proposed overhead lines Planned Corrective Maintenance OM&A expenditures for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 46 - Hydro One - Planned Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Planned Corrective Maintenance	2.0	1.8	2.6	3.9	3.8	6.7

The 2028 Test Year expenditure for Hydro One's Overhead Lines Planned Corrective Maintenance is $6.7M. This is a $4.7M (235%) increase relative to 2023 actual expenditures and a $3.9M (137.6%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by work to address the deferred low-priority defects and to keep up with the expected volume of medium priority defects. As of 2025 year-end, there were approximately 2,155 outstanding low-priority defects requiring remediation. According to Hydro One's defect correction process, low-priority defects are generally targeted for remediation within one calendar year to mitigate the risk of failures; however, the current repair rate is insufficient to address the volume of accumulated deferred work. The funding requested aims to reduce or eliminate all the low-priority defects.

3.4 UNDERGROUND CABLE MAINTENANCE OM&A - PROGRAM DETAILS

Underground transmission cable systems are used to transmit high voltage electricity below ground in areas where overhead lines are unsafe, not feasible, impractical or undesirable. They are typically installed beneath public roadways in densely populated urban centres connecting portions of the overhead network, generators and substations.

Maintenance programs are implemented to monitor cable condition and to identify and repair deteriorated components. Hydro One's cable maintenance programs include:

- preventive maintenance, comprising condition assessment and testing activities;
- corrective maintenance, comprising activities undertaken to investigate and repair equipment deficiencies; and
- cable locates, a legislative requirement to provide locate services for underground infrastructure.

Hydro One's cable asset strategy is to maximize service life. Given the potential for lengthy outages and the associated negative customer and environmental impacts of cable failures, the intent is to repair or replace underground system assets before unacceptable impacts to safety, the environment or reliability materialize. This strategy involves performing rigorous condition assessment, and prioritizing maintenance and repairs. Further details can be found in TSP Section 2.2, sub-section 3.2, Underground Cables.

Table 47 sets out Hydro One's planned Underground Cable Maintenance OM&A expenditures for the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years, for each program.

Table 47 - Hydro One - Underground Cable Maintenance OM&A ($M)[10]

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	0.8	1.1	0.8	1.2	1.2	1.9
Corrective Maintenance	4.1	2.3	2.2	1.6	1.6	2.9
Cable Locates	2.0	3.1	3.2	2.0	1.9	3.0
Total	**6.8**	**6.5**	**6.2**	**4.8**	**4.7**	**7.8**

The 2028 Test Year expenditure for Hydro One's Underground Cables Maintenance is $7.8M. This is a $1.0M (14.7%) increase relative to 2023 actual expenditures and a $2.0M (34.5%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is partially driven by the deferral of less critical maintenance activities during the 2023-2027 period and an increased number of locates. These expenditures are required to perform condition assessments, testing activities, investigate and repair equipment defects, and provide locate services.

3.4.1 UNDERGROUND CABLE MAINTENANCE OM&A - PREVENTIVE MAINTENANCE

The intent of the preventive maintenance program is to determine the condition of cable and ancillary equipment through inspection, assessment, testing, and diagnostics. This information is used to identify defects to be remediated through the Corrective Maintenance program and to plan capital replacement investments. Defects refer to assets that have failed, are near failure, in poor condition or at end-of-life. Poor condition assets are ideally addressed prior to experiencing extensive cable degradation or failures

[10] Figures presented in the tables may not sum to the totals shown due to rounding.

that could affect public and employee safety, the environment (oil leaks), system reliability and customers (loss of supply). Preventive maintenance activities are generally done cyclically and include activities such as condition assessment patrols, vault inspections, oil tests and analysis, thermovision and jacket tests.

Table 48 below sets out Hydro One's planned Preventive Maintenance OM&A expenditures in the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 48 - Hydro One - Preventive Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Preventive Maintenance	0.8	1.1	0.8	1.2	1.2	1.9

The 2028 Test Year expenditure for Hydro One's Underground Cables Preventive Maintenance is $1.9M. This is a $1.1M (137.5%) increase relative to 2023 actual expenditures and a $0.9M (86.3%) increase relative to the average annual expenditures over the 2023-2027 period.

The increase in proposed 2028 Test Year expenditures is primarily attributable to the deferral and subsequent reprioritization of preventive maintenance activities to remain within the overall transmission 2023-2027 OM&A budget.

3.4.2 UNDERGROUND CABLE MAINTENANCE OM&A - CORRECTIVE MAINTENANCE

Corrective maintenance activities are undertaken to investigate and repair cable and ancillary equipment defects with the intent of returning assets to their normal operating state. Defects are typically noted during preventive maintenance condition assessments, testing or trouble-call responses initiated by the ISOC due to an alarm or circuit outages.

Demand corrective maintenance addresses repairs requiring immediate attention such as failures resulting in an outage. Planned corrective maintenance addresses less critical defects not requiring immediate repair. Corrective maintenance activities include excavating and repairing cable components and locating and environmental remediation of oil leaks.

In addition, supplemental non-routine tests are done on a demand basis to verify repairs, obtain detailed condition data if routine testing results show abnormalities, and support the selection and prioritization of replacement candidates. These non-routine tests are typically more intrusive, sometimes destructive, costly, require specialized equipment, and often cannot be done with internal resources (i.e. contractors are required).

Table 49 below sets out Hydro One's planned Corrective Maintenance OM&A expenditures in the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 49 - Hydro One - Corrective Maintenance OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Corrective Maintenance	4.1	2.3	2.2	1.6	1.6	2.9

The 2028 Test Year expenditure for Hydro One's Underground Cables Corrective Maintenance is $2.9M. This is a $1.2M (29.3%) decrease relative to 2023 actual expenditures and a $0.5M (22.9%) increase relative to the average annual expenditures over the 2023-2027 period.

The higher costs in 2023 were due to the repair and environmental remediation of a low-pressure liquid-filled (LPLF) cable splice failure and associated oil leak on circuit C7E; refer to TSP Section 2.2, Section 3.2, Underground Cables.

3.4.3 UNDERGROUND CABLE MAINTENANCE OM&A - CABLE LOCATES

Underground cable locates is the process of identifying and marking the position of buried infrastructure. It involves reviewing drawings, performing on-site assessments and ground marking, and providing documentation to the locate requester.

In Ontario, requesting and obtaining locates before any excavation is legally required. Upon request, Hydro One is required by the *Ontario Underground Infrastructure Notification System Act*,[11] to provide locate services for its underground infrastructure. Hydro One receives approximately 8,000 transmission locate requests per year. Locates are a 24/7/365 service which is necessary for emergencies where there is a loss of essential service or danger to the public.

Accidentally striking or digging into underground cable can lead to significant safety hazards and environmental contamination in the event of electrical faults or the release of high-pressure oil, and extended circuit outages and customer interruptions to facilitate repairs. This program is necessary to ensure compliance with legislative obligations, safeguard workers, public and the environment, and prevent damage to high voltage transmission assets.

Table 50 below sets out Hydro One's planned Cable Locates OM&A expenditures in the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 50 - Hydro One - Cable Locates OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Cable Locates	2.0	3.1	3.2	2.0	1.9	3.0

[11] *Ontario Underground Infrastructure Notification System Act, 2012*, S.O. 2012, c. 4

The 2028 Test Year expenditure for Hydro One's Cable Locates is $3M. This is a $1.0M (50.0%) increase relative to 2023 actual expenditures and a $0.6M (23.0%) increase relative to the average annual expenditures over the 2023-2027 period.

4.0 ENGINEERING AND ENVIRONMENTAL SUPPORT PROGRAM DESCRIPTION & VARIANCE DISCUSSION

The sections below provide further details regarding Engineering and Environmental Support Sustainment category.

The Engineering and Environmental Support program supports a wide range of activities, including management of records and drawings, database management and provision of specific technical information, technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response, and funding of external technical expertise when needed.

This program is primarily demand-driven, in that it is driven by the level of work required to support the transmission capital work programs. The technical support and specialized studies are completed on an ad hoc basis to aid in the decision-making process and justification for capital investments. Table 51 below sets out Hydro One's planned OM&A expenditures for this program in the Test Year, along with the forecast and actual spending levels for the Bridge and Historical Years.

Table 51 - Hydro One - Engineering and Environmental Support OM&A ($M)

Description	Historical Years				Bridge Year	Test Year
	2023 Actual	2024 Actual	2025 Actual	2026 F/cast	2027 F/cast	2028 F/cast
Engineering and Environmental Support	6.4	7.3	7.2	7.1	7.3	8.1

The 2028 Test Year expenditure for Hydro One's Engineering & Environmental Support is $8.1M. This is a $1.7M (26.6%) increase relative to 2023 actual expenditures and a

$1.0M (14.4%) increase relative to the average annual expenditures over the 2023-2027 period.

The proposed 2028 Test Year expenditure relative to the average annual expenditures over the 2023-2027 period is primarily driven by increased Maintenance Technical Services to support transmission capital work, including engineering design and maintenance support associated with IT/BR/TF Corridor AC/DC Breaker and Transformer Schemes. While higher than the average annual expenditures over the 2023-2027 period, the 2028 expenditure remains generally consistent with historical Engineering and Environmental Support spending patterns.

TRANSMISSION DEVELOPMENT OM&A

1.0 OVERVIEW

Transmission Development OM&A (Development OM&A) consists of expenditures required to (i) develop and/or update the required technical standards for transmission power assets, (ii) support advancements and adoption of new technologies aimed at improving operational effectiveness, safety, and system reliability, and (iii) address and/or mitigate (where possible) issues affecting the reliability and quality of delivered power. These activities benefit customers by helping to ensure safe and reliable operation of the transmission system and by addressing issues that are important to the day-to-day operations of customer facilities.

The Development OM&A expenditures fund the following three programs:

- Transmission Standards Program;
- Research Development and Demonstration (RD&D) Program; and
- Customer Power Quality (PQ) Program.

A summary of the Development OM&A expenditure is provided in Table 1 below.

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

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Transmission Standards Program	3.8	4.7	3.2	4.9	4.8	5.4
RD&D Program	8.5	7.2	4.7	6.0	5.7	6.8
Customer PQ Program	0.4	0.2	0.3	0.8	0.8	0.8
Total Development	**12.7**	**12.0**	**8.2**	**11.7**	**11.3**	**13.0**

Hydro One's 2028 Test Year expenditure for Development OM&A is $13.0M, a $0.3M increase over 2023 actuals and a $1.8M increase over the average of the last rate period (2023–2027). The increase is driven primarily by higher planned expenditures for the Transmission Standards Program and RD&D Program, partially offset by Customer PQ Program expenditures that remain consistent with the 2026–2027 forecast. Overall, the increase reflects a continued focus on maintaining reliability and operational effectiveness while supporting the integration of evolving technologies, increasing system complexity, and customer requirements.

2.0 PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below summarize the Test Year costs for each of the three Hydro One Development OM&A programs.

2.1 TRANSMISSION STANDARDS PROGRAM

The Transmission Standards Program supports the planning, design, installation, operation, and maintenance of Hydro One's transmission system by maintaining, updating and/or developing new transmission technical standards for power system assets such as stations, transformers, lines, protection and control equipment, and other transmission equipment. Technical standards are continuously evolving, and new standards are being introduced by external bodies and equipment manufacturers. It is important for Hydro One to thoroughly assess and investigate these increasingly complex standards, document them in a comprehensive manner, communicate them consistently throughout the organization, and integrate them into its investment planning process.

Hydro One's technical standards provide a framework for the consistent application of engineering principles, resulting in design and maintenance approaches that improve efficiency, maintainability and operational performance.

Technical standards ensure that clear direction and work procedures are in place to safeguard employees and the public where electrical equipment is installed, operated and maintained. Through repeatable and consistent designs, maintenance practices are

standardized and bulk purchasing is enabled, which is expected to lower total asset lifecycle costs.

Standards are also incorporated into internal policies and requirements to ensure compliance with new and existing industry standards and codes, such as the Transmission System Code (TSC). This program supports the development of standards triggered by changes to reliability standards from organizations such as the North American Electric Reliability Corporation (NERC) and/or the Northeast Power Coordinating Council (NPCC), as well as revisions to industry-wide, externally developed industry standards. As new technologies are introduced and system complexity increases, Hydro One will continue to create, modify and update standards to facilitate the integration of these technologies with its legacy systems.

Furthermore, the Transmission Standards Program manages Hydro One's external standards subscriptions. This includes service-level agreements with standards development organizations, including the Institute of Electrical and Electronics Engineers (IEEE) and the CSA Group. This also includes third-party information service providers to obtain access to other global standards, such as IEC and ISO standards, and technical resource organizations that support standards development, such as CIGRE. These subscriptions provide employees across the company with access to relevant industry standards.

Hydro One participates in industry standards groups to better understand emerging standards and influence their development. With the many factors increasingly affecting the provision of transmission service, including climate change and cyber security, it is important that Hydro One stay abreast of the latest developments. Contributing its experience and expertise through participation in these forums allows Hydro One to influence standards under development and helps it remain an industry leader.

Hydro One reviews its existing technical standards in accordance with its revision cycles that are based on the specific asset or equipment type and applicable compliance

requirements. The development of new standards may be necessitated by the adoption of new equipment and technologies and/or the need to address compliance requirements. For example, in recent years, considerable effort has focused on updating standards related to critical infrastructure protection.

Table 2 below sets out Hydro One's planned expenditures for the 2028 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for the Transmission Standards Program.

Table 2 - Transmission Standards Program OM&A ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Transmission Standards Program	3.8	4.7	3.2	4.9	4.8	5.4

Hydro One's 2028 Test Year expenditure for the Transmission Standards Program is $5.4M, a $1.6M increase over 2023 actuals and a $1.1M increase over the average of the last rate period (2023–2027). The lower expenditure in 2025 reflected competing compliance priorities that affected transmission subject matter expert availability and deferred certain standards development work. The 2028 Test Year forecast reflects the planned completion of deferred standards development, ongoing review and updates to technical standards, and higher external standards subscription costs.

2.2 RESEARCH DEVELOPMENT AND DEMONSTRATION PROGRAM

The RD&D Program supports Hydro One's adoption of new technologies to improve operational effectiveness, safety, and system reliability. This program addresses: (i) operational needs by resolving technical challenges experienced by Hydro One to improve the management of existing transmission facilities and deliver safe and reliable supply to customers, (ii) strategic needs by engaging in research and demonstration of emerging technologies, and (iii) broader electricity industry changes driven by innovation and policy initiatives (e.g., OEB's Innovation Sandbox).

The following transmission-related initiatives are examples of work supported by the RD&D Program:

Emerging Technologies

The RD&D Program enables demonstration projects to evaluate the performance and suitability of selected new technologies and validate them in an operating environment, reducing uncertainty around adoption while prioritizing learning to support potential future application. The program also invests in the development of applications for emerging technologies that improve information gathering and operational performance. By improving available data, this work also enables Hydro One to further integrate data-driven capabilities, including advanced analytics and artificial intelligence, where appropriate, to enhance decision making and operational insights. Currently, Hydro One's RD&D efforts in this area are focused on:

- **Exploring Alternative Asset Technologies:** The RD&D Program supports research, testing, and evaluation of suitable alternative technologies at varying stages of maturity. Current evaluations include emerging SF_6-alternative breaker technologies and alternative station battery technologies that are newly available but not broadly evaluated by utilities. The objective of this work is to determine whether these alternatives satisfy requirements, build experience through experimentation and integration, and improve readiness for potential adoption.
- **Enhancing Asset Sensing Applications:** Through collaborative laboratory testing and demonstration projects with vendors and research organizations, this work includes evaluating the performance and suitability of emerging transmission lines and station sensing technologies, such as advanced real-time sensors and station monitoring applications. The objective is to test and learn new approaches that enhance data availability to enable operational insights and improve situational awareness.

Innovative Practices and Technologies

The RD&D Program investigates better ways of doing current work, with the potential to improve efficiency, health, and safety and maintain the reliability of the transmission system. The innovative technologies that are a focus of current RD&D efforts can be grouped into the following four areas:

- **Overhead Transmission Practices and Technologies:** The goal of this research is to improve safety and reliability in the operation and maintenance of transmission lines and to identify approaches to cost-effectively maintain or increase transmission capacity. This research focuses on overhead transmission line issues, including corrosion of structures and components; lightning and grounding; line hardening; emerging designs; polymer, composite, porcelain, and glass transmission insulators; and practices for construction and maintenance.
- **Underground Transmission Practices and Technologies:** The goal of this research is to improve the operation and maintenance of existing underground cable facilities and to ensure the effective design and implementation of new facilities to meet anticipated system needs. This research focuses on underground cable issues, including cable ratings; inspection technologies; thermo-mechanical performance; advanced sensing and monitoring; and buried steel pipe corrosion.
- **Transmission Substations Practices and Technologies:** The goal of this research is to improve the lifecycle management of substation assets, by examining issues relating to new materials; component aging; and monitoring techniques for assets such as transformers, ground grids, circuit breakers, protection and control equipment.
- **Transmission Environmental Practices and Technologies:** The goal of this research is to examine a broad range of subjects, including transmission-line siting; spill prevention, containment, management and remediation; prevention of animal interactions; sensitive species protection; and the selection and management of dielectric fluids.

Much of the research undertaken as part of the RD&D Program is conducted through industry organizations, including the Electric Power Research Institute (EPRI) and the

Centre for Energy Advancement through Technological Innovation (CEATI), on a subscription basis. This participation model is a cost-effective approach that allows Hydro One to leverage joint funding with other utilities, risk sharing, and access to the broader expertise of companies with similar interests and challenges.

Table 3 below sets out Hydro One's planned expenditures for the 2028 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for the RD&D Program.

Table 3 - RD&D Program OM&A ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
RD&D Program	8.5	7.2	4.7	6.0	5.7	6.8

Hydro One's 2028 Test Year expenditure for the RD&D Program is $6.8M, a $1.7M decrease from 2023 actuals and a $0.4M increase over the average of the last rate period (2023–2027). The lower expenditure in 2025 reflected reprioritization and work deferrals, including the cancellation of a project that did not advance beyond laboratory testing and the deferral of subsequent phases pending stabilization. The 2028 Test Year forecast reflects continued focus on assessing and demonstrating emerging technologies, advancing data capture techniques and methodologies, and identifying opportunities to improve operational performance through new capabilities.

2.3 CUSTOMER POWER QUALITY PROGRAM

The Customer Power Quality (PQ) Program is designed to address the quality of delivered power, which can materially affect customers' operations and satisfaction. The effect of PQ issues on customers depends on their individual circumstances and is a function of:

- the nature, severity and frequency of the PQ issue; and
- the sensitivity of customer equipment or processes to PQ disturbances.

Voltage sags due to faults occurring on power systems are a principal cause of many equipment and process disruptions experienced by industrial customers, such as automotive plants, manufacturing facilities, and material processing plants. This causal relationship has been well established by the power industry as well as by industry groups, and it is universally accepted that PQ issues are more practical and cost-efficient to manage closer to the end-use equipment within customer facilities that has the potential to be disrupted.

Through the Customer PQ Program, Hydro One assists its customers in understanding and investigating the sensitivity of plant equipment to power quality disturbances that are inherent in electricity supply systems. In particular, Hydro One undertakes the following activities through the Customer PQ Program:

- Expanding power quality monitoring capabilities by enabling PQ monitoring features in existing Hydro One and customer revenue meters;
- Managing PQ related database software and monitoring systems;
- Investigating PQ disturbances and ensuring compliance with internal and industry PQ standards;
- Co-funding third-party customer PQ audits to identify weak links in power quality resiliency, analyze available power quality data, and make specific recommendations to improve equipment resilience to such future PQ events; and
- Collecting and archiving historical lightning activity data (spatial location and intensity), as gathered from a lightning detection system hosted by an external service provider. The information gleaned from this database allows monitoring and identifying transmission lines experiencing undue lightning outage rates, so that consideration may be given to possible upgrades or mitigation. It is also needed for investigating customer PQ complaints to establish the cause of particular disturbances and to identify effective response strategies.

The Customer PQ Program also allows Hydro One to work on PQ issues with customers. The program provides customers with detailed information about the PQ environment, a term defined to include the characterization of unwanted deviations of the supply voltage

from its intended ideal character, including the frequency of such occurrences. This information about the PQ environment facilitates a coordinated approach to managing PQ performance while recognizing the inherent limitations on the power delivery system to address individual customer issues within customer facilities. As part of this initiative, Hydro One is continuing to expand its PQ monitoring capability across the network, providing better visibility into events and causes, which supports Hydro One's efforts, to resolve PQ issues with customers. Continuing to enable this assessment is increasingly important as weather events and system complexity continue to increase.

Table 4 below sets out Hydro One's planned expenditures for the 2028 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for the Customer PQ Program.

Table 4 - Customer PQ Program OM&A ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Customer PQ Program	0.4	0.2	0.3	0.8	0.8	0.8

Hydro One's 2028 Test Year expenditure for the Customer PQ Program is $0.8M, a $0.4M increase over 2023 actuals and a $0.3M increase over the average of the last rate period (2023–2027). The 2028 Test Year forecast supports customer enrolment in the PQ monitoring initiative, third-party audit activities, and management of PQ monitoring systems. Expenditures are consistent with the 2026–2027 forecast and reflect the realignment of PQ monitoring system costs that were previously captured under a different maintenance program.

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TRANSMISSION CUSTOMER CARE OM&A

1.0 SUMMARY OF TRANSMISSION CUSTOMER CARE OM&A

Hydro One's transmission system effectively serves the entire province—over 90% of electricity customers in Ontario. Most electricity customers are served by a local distribution system and, thus, are indirectly connected to Hydro One's transmission system. Transmission-connected customers (LTX) include over 260 customers of three types that connect directly to the transmission system: Local Distribution Companies (LDCs), Generators and large End-users.

LTX customers represent large electricity consumers and important companies for Ontario's economy whose energy needs are critical inputs for the long-term planning of the transmission system. Hydro One's Account Executives, who are part of the Transmission Large Customer Account Management group, serve a key function as the main point of contact for these customers and are committed to meeting their evolving needs through proactive, collaborative and well-engaged customer relationships. The group focuses on positively influencing customer relationships and providing transparent, responsive, and cost-conscious customer service. The group communicates with customers on matters that include customer connection requests, sustainment and system development plans, and concerns regarding service outage levels or power quality.

Customer demand in the current rate period has been unprecedented. There has been significantly increasing customer connection growth, as described in TSP Section 2.9.2.1. This is driven by significant growth in decarbonization and electrification, the emergence of new technologies such as electrical vehicle manufacturing and data centers, along with the addition of new capacity and energy procurement initiatives by the Independent System Electricity Operator (IESO).[1] This has required the Transmission Large Customer Account Management group to prioritize and focus on managing this growth, including handling inquiries and ensuring Hydro One meets the regulated obligation to process and

[1] TSP Section 2.1.3.1 and Section 2.8.3.2

connect applicants. This has involved more intake meetings, more process and engineering reviews and more agreements that needed to be processed.

During the current rate period, the Transmission Large Customer Account Management group adapted to the significant increase in new connection activity by prioritizing mandatory connection-related work while continuing to support more than 260 existing transmission-connected customers. This prioritization enabled the group to manage the increased connection workload using existing resources but reduced its capacity to undertake certain proactive relationship-management activities for existing customers at historical frequencies. This was a necessary near-term response to rapidly increasing workload rather than a sustainable operating model.

In the 2028-2032 rate period, connection-related demand is expected to remain elevated while the group continues to support the operational and relationship-management needs of existing transmission-connected customers. Additional resources are therefore required to support Hydro One's connection obligations, manage a growing and increasingly complex pipeline of customer projects, and maintain effective engagement with existing customers. This will provide the capacity required to support both new connection customers and the existing customer base without relying on the temporary prioritization measures adopted during the current rate period.

2.0 PROGRAM DESCRIPTION

The Transmission Large Customer Account Management group provides a range of services to LTX customers, including (i) supporting customer connection requests and serving as a key customer interface throughout the connection process; (ii) responding to customer inquiries and providing proactive outreach and tailored advice; (iii) coordinating the investigation of operational issues and the development of mitigation plans; and (iv) negotiating, administering and managing connection and operational agreements.

Hydro One's Account Executives provide a critical interface between transmission customers and the Hydro One teams responsible for assessing and delivering customer

connections. Account Executives meet with transmission customers on a regular basis to identify their needs and develop action plans to address these needs. On the operational side, they proactively engage with transmission customers to review and coordinate Hydro One's asset management and outage plans. This approach minimizes customer impact and optimizes opportunities for both Hydro One and its customers to effectively plan and execute work on their respective facilities.

These customer support activities also support the settlement functions to ensure the integrity of financial transactions between Hydro One, the IESO, and applicable LTX customers. As additional transmission customers and delivery points are connected, the associated settlement workload is expected to increase, including the review, reconciliation and exception-management activities required to support accurate customer billing. Settlement activities include:

- calculating gross load-billed quantities at specific delivery points;
- reviewing and approving transmission totalization tables;
- reviewing and approving IESO transmission delivery point site registration reports and meter connectivity;
- reconciling transmission delivery point quantities and charges; and
- identifying anomalies and exceptions in metering data used by the IESO to bill Hydro One LTX customers.

3.0 EXPENDITURES LEVEL

Table 1 summarizes Hydro One's Transmission Customer Care OM&A expenditures for the historical (2023-2025), forecast (2026), bridge (2027), and test (2028) years.

Table 1 - Summary of Customer Care OM&A Allocated to Transmission ($M)

	Historical				Bridge	Test
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Customer Care	6.3	6.6	6.8	5.0	4.9	6.8
Total	**6.3**	**6.6**	**6.8**	**5.0**	**4.9**	**6.8**

The 2028 Test Year expenditure for Transmission Customer Care OM&A is $6.8M, a $0.5M increase over 2023 actuals, and a $0.9M increase over the average of the last rate period (2023-2027).

The 2028 forecast is in line with 2025 expenditures. It is also $0.6M, or 9% lower than the $7.4M resulting from the adjustment of the last rebasing year's (2023) actual expenditure by the OEB's annual inflation factor, reduced by the stretch factor.[2] This is due to: (i) an expense reallocation from Transmission to Distribution associated with the reorganization of customer teams referred to above, which resulted in a reduction in Transmission-allocated expenses starting in 2026, as reflected in Table 1; and (ii) an offsetting increase in forecast expenses, largely attributable to the additional resources required in 2028. Due to the increasing volume and complexity of customer connections, large customer engagement activities will require increased in-person consultation and engagement going forward. This need has become evident through customer feedback, marketplace energy procurement programs and increasing customer demand.

The customer care plan aims to provide the resources required to manage increasing connection activity while continuing to support existing transmission-connected customers. Customer experience remains an important program outcome, supported by responsive communication, transparent processes and effective coordination throughout the customer relationship. The need for additional resources is driven by a substantial and sustained increase in connection-related workload and the requirement to support Hydro One's applicable connection obligations.

During the current rate period, the Transmission Large Customer Account Management group has managed a significant increase in customer demand across all three customer segments. This increase includes load connection requests, local distribution community growth, and generation development, alongside IESO procurements and major

[2] 2023 actual expenditures adjusted by net OEB inflation (I-X) to 2028 = $6.3M * (1+5.3%) * (1+3.6%) * (1+3.4%) * (1+2.8%) * (1+2.8%) = $7.4M. The difference between 2028 forecast and 2023 actual expenditures adjusted by net OEB inflation to 2028 is ($6.8M/$7.4M - 1)*100% = -9%.

infrastructure initiatives such as Metrolinx and high-speed rail electrification. Together, these have resulted in a substantial and sustained increase in the group's workload.

Looking ahead, the pipeline continues to expand and includes complex, multi-year projects involving data centers; local distribution companies increasing load and piloting interim smart grid solutions; Hydro One's strategic projects requiring intensive customer coordination; major nuclear investments; and large-scale transportation and industrial infrastructure. Importantly, much of this growth is still in its early stages and will span multiple years, while the group continues to manage its ongoing relationships with existing customers. Enabling this crucial work while effectively supporting both new prospects and existing customers will require additional effort and resources for customer engagement, relationship management, and contract administration.

The Transmission Large Customer Account Management group is critical to facilitating major investments, enabling customer connections and meeting Hydro One's applicable connection obligations. Connection-related activity has increased significantly during the current rate period and is expected to remain elevated as the pipeline of customer projects advances. The 2028 budget provides the additional resources required to manage this increasing workload while continuing to support both new and existing transmission customers.

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TRANSMISSION O&M WORK EXECUTION STRATEGY

1.0 INTRODUCTION

This Exhibit describes the approach Hydro One uses to efficiently deliver its large and complex transmission Operations and Maintenance (O&M) work program while meeting approved expenditure levels. The company completes its annual transmission O&M work program according to an established Program Delivery Process that is robust and repeatable. The Program Delivery Process contributes to meeting the business objectives described in the TSP, system reliability, customer needs, regulatory requirements, and ensuring a safe environment for workers and customers.

This exhibit begins by describing the phases of the Program Delivery Process with details of transmission O&M program scopes. This is followed by a discussion of Hydro One's safety culture and initiatives, and continuous improvement model.

2.0 PROGRAM DELIVERY PROCESS

The Program Delivery Process for the transmission O&M work program comprises three main phases:

1. Investment Planning
2. Program Development:
    a. Work Program Planning
    b. Work Initiation and Scheduling
3. Program Execution

Each of these phases and sub-phases are discussed in the sections that follow. Figure 1 shows the Program Delivery Process starting from initial Investment Planning phase through to the Execution phase.

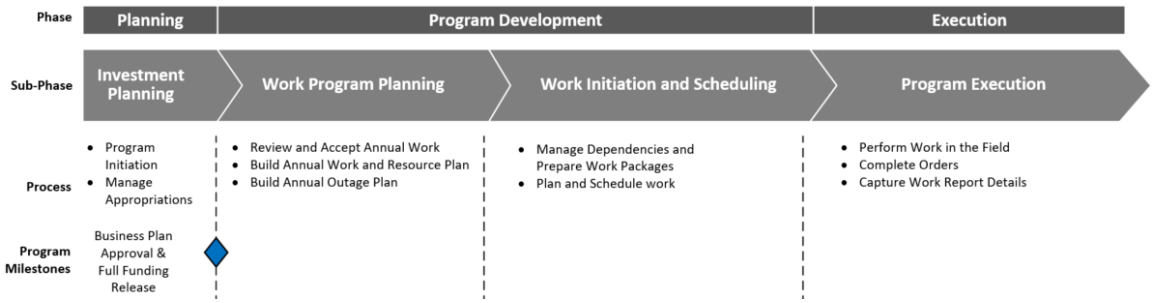

Figure 1: Transmission O&M Program Delivery Process

2.1 INVESTMENT PLANNING

The Investment Planning process determines the frequency and nature of maintenance activities optimized to make best use of the transmission O&M funding, as discussed in Section 1.7 of the System Plan Framework (SPF). Hydro One's O&M Program Delivery Process is used to develop and execute the programs necessary to meet the investment plan. The work is released on an annual basis after the approval of the investment plan. Program managers and the execution lines of business (i.e. Stations Services, Transmission Lines, and Forestry) are involved in the Investment Planning process to ensure that execution factors are considered in optimizing delivery of the programs. This collaborative effort also allows for program scope and cost to be determined at the Investment Planning phase. Visibility to future year scope is provided to the executing lines of business to help plan resources, training, and material purchases. Additionally, it gives them the opportunity to gain efficiencies by bundling work geographically or bringing work forward if an execution challenge is encountered (e.g., a cancelled outage, resource conflict or permit issue).

2.2 PROGRAM DEVELOPMENT

The Program Development phase consists of the Work Program Planning and Work Initiation and Scheduling sub-phases.

2.2.1 WORK PROGRAM PLANNING

Once the programs are released to the executing lines of business, the Work Management Team, comprised of program managers, works with the executing lines of business to plan

the outages, resources, material, and equipment to safely and efficiently deliver the planned work program. The Work Management Team seeks to further optimize the work program, looking at enablers such as resources and system outages across the entire portfolio of transmission and distribution work. For example, Stations Services and Transmission Lines bundle work across multiple programs to ensure resource efficiency by executing as many units as possible during an outage. Forestry's Work Management Team consists of Planners, Schedulers and Program Managers who work with Field leadership to optimize work execution and bundle its transmission programs where possible to promote efficiency and optimization.

2.2.2 WORK INITIATION AND SCHEDULING

During Work Initiation and Scheduling, detailed work packages are prepared for the executing workgroups capturing material, equipment, and standards required to complete the work safely. Maintenance work is scheduled for execution considering the criticality of work, resource availability and utilization, staff and public safety, as well as the requirement for system outages. Work is bundled when scheduling to make best use of outages and resources, limiting the number of planned bulk electric system outages required. Much of Hydro One's transmission O&M work requires an outage to safely and efficiently execute. Given the number and variety of work programs that Hydro One is executing, outage planning is a significant effort and is done initially through an annual planning process and refined through a continually rolling outage planning process.

2.3 PROGRAM EXECUTION

At the Program Execution phase, Stations Services, Transmission Lines, and Forestry are responsible for safely and efficiently executing the O&M work program as planned, and are responsible for reporting scope schedule and cost variances. Program Managers from these three lines of business work closely to identify and report any unforeseen issues requiring additional time or resources so that work can be reprioritized effectively. They are also responsible for providing meaningful input on the condition of assets and any potential risks or opportunities that may impact the Hydro One system.

3.0 PROGRAM OVERSIGHT AND GOVERNANCE

As part of the Program Delivery Process, Hydro One performs program management and controls, tracking and reporting, and follows governance to optimize the delivery of the transmission O&M work program. This section describes these activities.

3.1 PROGRAM MANAGEMENT AND CONTROLS

The program manager is the single point of contact on a program and is critical to its success. Program managers are accountable for planning, coordinating, tracking and reporting on the program during both the Program Development and Program Execution phases and are accountable for providing leadership, communication, coordination, cost control, schedule management, and risk management. Assigning these accountabilities to a single individual reduces handoffs during the program lifecycle and provides a consistent approach to development and execution.

Hydro One implements controls across the transmission O&M work programs through a comprehensive set of measures to create a structured, data-driven approach to managing programs. This includes reviewing scope, schedule, and cost performance through standardized templates, ensuring timely visibility into risks and variances, as well as constant communication between planning and the executing lines of business to enhance coordination, confirm work readiness, and proactively address constraints.

3.2 TRACKING AND REPORTING

Hydro One reviews its transmission O&M program status monthly at both the individual program and portfolio levels with a focus on program spend, unit accomplishment and costs. These reviews ensure the O&M work program is well-managed, executed to plan, and that resources are redirected as required for optimal efficiency.

Programs are reviewed against their plans for expenditures and unit accomplishments to monitor any changes throughout the year and to compare against the previous year's performance. The Portfolio Management team also takes into consideration the risks and opportunities associated with specific programs to have visibility to potential issues before

they occur and act accordingly. Further, programs with regulatory requirements related to maintenance or inspection activities are tracked, reported on, and measured to ensure compliance is achieved. Hydro One incorporates these requirements into the efficient scheduling and execution of the transmission O&M work program.

3.3 GOVERNANCE

Material variances against plan are reviewed by the appropriate expenditure authority and where required reprioritization of investments follows the process described in SPF Section 1.7 to ensure effective planning and pacing of work during the plan period.

4.0 TRANSMISSION O&M WORK PROGRAM

Transmission O&M work is primarily executed by internal staff, in the areas of Stations Services, Transmission Lines, and Forestry.

The Station Services maintenance work program is underpinned by preventive maintenance programs designed to monitor and ensure the health of power system equipment. Preventive maintenance activities are based on frequency cycles specific to the type and make of the equipment, or in some cases the number of operations a device has experienced or other condition-based triggers. Maintenance activities include visual inspections and selective intrusive inspections of the internal working components of power equipment such as transformers and circuit breakers. Diagnostic and operating tests are performed to assess the condition of power systems, auxiliary equipment, as well as protection, control and telecom systems. The frequency of maintenance activities is determined and reviewed based on regulatory requirements and asset health assessments to ensure compliance and to maximize the effective use of planned maintenance funding, power system reliability and useful equipment life.

Corrective maintenance in stations can result from inspection findings, trouble calls in response to automated equipment monitoring alarms, and dispatch from the Integrated System Operating Centre (ISOC). Inspection results requiring attention are logged as defect reports, which are prioritized, either as requiring urgent attention or to be planned

for remediation. Non-urgent maintenance and repairs are planned and scheduled to make the most efficient use of resources and outages. The common types of corrective activities performed are switch repairs, breaker repairs, oil leaks, transformer fan/cooling repairs and right of way maintenance. Defects requiring full component or asset replacement are addressed under the transmission Capital Work Program.

The Transmission Lines maintenance work program includes inspections and assessments of equipment including conductor, shieldwire, insulators, steel and wood structures, switches and high-voltage underground cables. Inspections and assessments on these transmission system assets allow for the proactive identification of defects which, if not addressed, could result in reliability or safety concerns. Data collected from assessments on asset condition also informs the capital refurbishment and replacement programs.

Corrective maintenance on transmission lines, as in stations, is identified through inspections and foot patrols, and during trouble calls. Defect reports are prioritized, and either addressed as urgent repairs, or scheduled for remediation. Scheduled repairs are prioritized, and planned for the most efficient utilization of resources, material and outages. The common types of activities performed are repairs on insulator structures, towers, pole structures and shieldwire component repairs. Defects requiring asset replacement are addressed under the transmission capital work program.

The Forestry maintenance work program is focused on safely managing vegetation on Hydro One's transmission right-of-way corridors and at Hydro One transmission facilities to maintain system reliability. Preventive maintenance activities include transmission vegetation notification, annual vegetation patrols, virtual patrols, line clearing, brush control and station spray. The brush control program involves managing vegetation growth to satisfy standing and falling clearance distances to overhead conductors, while the line clearing program is focused on removing or selectively trimming vegetation and danger trees on the edge of or adjacent to the right-of-way, that have the potential to exceed clearances.

The line clearing and brush control programs are cyclical in nature. The associated cycle lengths are taken into consideration when annual programs are planned and circuit selection occurs, which is particularly important to ensure compliance with NERC regulations.

A portion of the overall work program involves unplanned maintenance to address vegetation deficiencies that require treatment prior to the next scheduled cyclical maintenance activity. Trouble call response and storm restoration efforts also require Forestry support as many weather events result in tree-related incidents that require the expertise of forestry crews to clear downed trees and other unwanted vegetation.

5.0 EXECUTION RESOURCES

Hydro One relies on the expertise of a high-performing, skilled workforce to complete its work program. The transmission O&M work program will necessitate a minor increase in resources starting in 2028. Maintaining a relatively flat regular headcount while absorbing the increased workload through casual resources ensures flexibility, scalability, and cost control. For more details of transmission's resource plan for the 2028-2032 period see Exhibit E-06-02 Workforce Planning.

The company also realizes economies of scale and efficiencies by integrating its transmission and distribution workforces, and capital and O&M work where it is advantageous to do so. The mix of full-time and temporary staff provides the needed flexibility to support the fluctuations in the work program, which result from the seasonal nature of some work, the need to react to emergent situations and evolving asset requirements. This approach allows for knowledge retention while supporting operational agility and long-term sustainability.

6.0 SAFETY CULTURE

As part of its commitment to becoming the safest and most efficient utility, Hydro One's goal is to reduce and eliminate life-altering injuries. The company's refreshed Health and Safety Plan builds on the strong foundation established through the 2020-2024 Safety

Improvement Plan and reflects input from across the organization, including frontline employees, survey results and focus groups. This is supported by the introduction of the Safety Absolutes: a set of guiding principles focused on the most critical hazards that could lead to a life-altering injury.

The company continues to adopt the philosophy that a safe utility is also an efficient utility. Hydro One continues to improve workplace health and safety through its Human Performance program. The overall goal of Human Performance is to ensure that frontline workers and supervisors are well informed of potential risks and are actively engaged in safe work planning. The program recognizes that people make errors and therefore seeks to determine root causes of human errors and then implement tools, processes, and coaching techniques for improvement.

Weekly safety bulletins are distributed and shared with staff at Monday morning tailboard sessions to ensure planning discussions are relevant. Onsite planning meetings are carried out at the start of each day and after breaks to refocus staff and reinforce safe work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone's viewpoints are heard.

In addition, Hydro One is advancing psychological safety through leadership presentations and programs designed to foster a consistent and supportive environment, promote proactive measures that protect employee wellbeing, and establish clear accountability mechanisms to ensure program effectiveness.

For more information regarding the company's approach to safety in the execution of its transmission work see TSP Section 2.11, subsection 2.11.6 – Factors Impacting Work Execution.

7.0 CONTINUOUS IMPROVEMENTS

Hydro One has recently undertaken initiatives to increase the effectiveness and efficiency within the delivery of its O&M work program. These initiatives are described in the following sections.

7.1 CONTINUOUS IMPROVEMENT MODEL – FIELD PRODUCTIVITY INITIATIVES

Over the 2021-2022 period, Hydro One implemented the Continuous Improvement Model (CIM) across multiple executing lines of business, including Station Services and Transmission Lines, to further improve labour efficiencies in work execution. The CIM is a system of integrated elements to plan, execute and measure work completion. It focuses on clarifying roles and accountabilities resulting in more efficient work assignments, reduced variances between planned and actual project durations and decreasing downtime through increased scheduling efficiency. The CIM drives continuous operational effectiveness by ensuring safety, quality of service and cost management.

CIM provides a framework to address three fundamental areas:

- Providing a structured methodology and tools for more effective planning, work execution and reporting, which results in more efficient work execution.
- A province-wide problem resolution program that facilitates the identification, prioritization and tracking of continuous improvement opportunities in execution.
- Alignment of roles, responsibilities and accountabilities across the work management and execution teams that ultimately drives improved work execution.

The ongoing benefits of this program include the following:

- Improved safety culture and engagement of crews, through enhanced field leadership tools and work execution rigour;
- Improved efficiency through proactive identification and prioritization of high impact activities;
- Increased efficiency through the use of more consistent scheduling tools;
- Increasing coordination to improve work management efficiency and reduce engineering rework; and

- Improved coordination of field activities to reduce work durations.

Based on the CIM, Hydro One has implemented systematic processes to quantify, categorize and escalate issues that arise during work execution. Issues are analyzed and addressed through a resolution process, using a consistent escalation framework with levels corresponding to the importance of the issue, to drive the implementation of permanent solutions. This has proven to increase engagement as staff are stakeholders in the development of solutions.

7.2 CREW SIZE OPTIMIZATION INITIATIVE

In 2025, Transmission Lines launched an initiative to further refine the crew deployment approach to ensure optimal crew size while maintaining productivity and safety. This has led to reduced costs and the ability to complete more work. This was achieved through the development of a safe crew sizing calculator, improved accuracy regarding time and unit reporting, and improved scheduling.

7.3 DRONE PATROLS

Drone patrol is a new method to conduct detailed structure and hardware inspections in no-fly or restricted areas, where traditional helicopter-based methods cannot be used. Detailed drone imagery is meant to complement foot patrols (which are insufficient for inspecting the upper portion of structures) and climbing inspections (which are too slow and expensive and can only be performed selectively). Therefore, the use of technology provides a more comprehensive and close-up evaluation of above-ground assets while enhancing safety, accessibility, and data quality.

7.4 LIVE LINE CONDUCTOR INSPECTIONS

Hydro One has started utilizing LineVue more extensively as an alternative to ‘short sampling’. LineVue is a non-destructive inspection tool for overhead power lines that enables live-line inspections on shieldwire and energized conductors, providing Hydro One with a safer, faster, and more cost-effective approach to managing critical infrastructure. It accurately measures steel core corrosion and wire breaks across entire

spans, delivering a comprehensive condition assessment rather than relying on isolated six-foot physical samples. By eliminating the need for outages or physical sampling, LineVue reduces operational costs and allows Hydro One to prioritize conductor and shieldwire replacements based on actual condition data. By identifying potential weaknesses before failure, the technology enhances public safety and grid reliability while enabling more effective prioritization of infrastructure upgrades and strengthening long-term system performance.

7.5 POLLINATOR HABITAT PROGRAM

Through jointly funded projects with external partners, such as WWF Canada and Canadian Wildlife Federation, Hydro One was able to add an additional 61.5 hectares of pollinator friendly habitat in 2024 and an additional 81.5 hectares in 2025. This program has created approximately 275 hectares of habitat across 50 projects since 2015. The initiative involves planting native seeds following mechanical vegetation management methods. Hydro One has received the 2025 Technology Transfer Award from EPRI for “Advancing the use of Native Seed Mixes on Utility Rights-of-Way and Substations”. Leveraging required vegetation management work to create habitat has numerous benefits, including improved acceptance from stakeholders, community members and landowners.

7.6 LIDAR

LiDAR is a remote sensing technology that is used by utilities to obtain accurate geospatial images and measurements of circuits and surrounding vegetation. After a successful pilot, Hydro One is formally integrating this approach into the annual vegetation program. This innovative approach will replace traditional ground and helicopter patrols for 50% of the network each year, ensuring full coverage over a two-year cycle. By adopting Virtual Patrols through LiDAR, Hydro One will enhance visibility across the scanned portion of the network, improve the timeliness and data-driven nature of decision-making, and manage risk.

8.0 CONCLUSION

Hydro One's use of the Program Delivery Process, including its application of strong oversight, reporting and resourcing practices, creates a robust and repeatable approach to efficiently delivering a large and complex transmission O&M work program. The approach also provides the company with flexibility to meet the demands of a changing environment in a safe and effective manner. Hydro One remains committed to continuously improving its execution strategy and realizing the safe, efficient and cost-effective execution of maintenance work.

HOSSM OM&A

1.0 SUMMARY OF HYDRO ONE SAULT STE. MARIE OM&A

This Exhibit provides an overview of Hydro One Sault Ste. Marie LP's (HOSSM) Operations, Maintenance and Administration (OM&A) expenses for the 2016 to 2025 historical period, 2026 Bridge Year and the 2027 and 2028 Test Years.[1]

In 2016, Hydro One Inc. received OEB approval to acquire Great Lakes Power Transmission LP (which was subsequently renamed HOSSM), as well as approval for a ten-year deferred rebasing period. Since October 1, 2018, HOSSM has been operationally integrated with Hydro One Transmission. However, HOSSM will remain financially and legally separate until such time that a permit in relation to transmission assets on First Nation reserve lands can be assigned to Hydro One. See Exhibit A-08-01 for further details.

HOSSM is managed by its general partner, Hydro One Sault Ste. Marie Inc (HOSSM GP). HOSSM GP and Hydro One are parties to affiliate service agreements, pursuant to which Hydro One plans and organizes the operation and maintenance of HOSSM's assets, provides certain corporate and administrative support to HOSSM, and executes work for HOSSM as outlined in Exhibit D-02-03.

Since Hydro One operationally integrated HOSSM, OM&A is planned and executed on the same basis as Hydro One Transmission, to meet public safety objectives, deliver outcomes valued by customers, maintain transmission system reliability at targeted performance levels, and comply with legislative and regulatory requirements.

The forecast Sustainment OM&A has been determined through Hydro One's Investment Planning process described in SPF Section 1.7 and TSP Section 2.7. HOSSM's OM&A expenses are responsive to the outcomes of the Transmission System Plan (TSP Section

[1] EB-2026-0170, Decision and Order, 14 July 2026: The OEB approved HOSSM's 2027 revenue requirement on an interim basis; 2027-2032 are being rebased as part of this Application, with 2027 and 2028 OM&A being the Test Years and 2029-2032 being set through the Custom IR framework.

2.10). The forecast Common Corporate Functions OM&A provides services on a shared basis to Hydro One and its affiliate companies, including HOSSM, and are allocated to HOSSM and other affiliate companies through a cost allocation methodology which is described in Exhibit E-04-08.

Table 1 sets out HOSSM's OM&A for the Historical, Bridge, and Test Years. The categories that comprise the overall OM&A envelope are similar to the categories used for Hydro One Transmission, which are described in Exhibit E-02-01.

HOSSM's proposed 2027 and 2028 Test Year OM&A of $10.6M and $10.9M, respectively, are required mainly to: (i) perform preventive and corrective maintenance on station equipment to identify and address deficiencies, assess asset condition, mitigate operational risks, and maintain system safety and reliability; (ii) maintain the protection, automation, and telecom systems required to protect, monitor, control, and operate the transmission system; (iii) maintain aging facilities and site infrastructure in a safe and functional condition; (iv) undertake vegetation management to maintain required clearances, support transmission system reliability, and comply with NERC requirements; (v) inspect and maintain overhead lines, and address defects, to preserve asset performance and transmission line reliability; and (vi) fund HOSSM's share of Common Corporate Functions & Services that support its operations.

The 2029 to 2032 OM&A is established in accordance with the Custom IR framework discussed in Exhibits A-04-01 and A-04-02.

The 2027 and 2028 Test Year OM&A are lower than the 2016 OEB-approved OM&A, primarily due to sustainable efficiencies arising from access to specialized resources and expertise, and standardized business processes delivered by Hydro One. These efficiencies help reduce duplication and enable asset and system needs to continue to be addressed in a cost-effective manner. Additional savings resulted from eliminating the former HOSSM control centre function and reducing IT procurement, maintenance and licensing costs, as discussed in Section 2.1 below.

Over the deferred rebasing period, HOSSM's cumulative actual and forecast OM&A is approximately $28.6M lower than the MAADs Status Quo Forecast scenario (i.e., "without transaction"), compared to the forecast savings of $11.7M for the MAADs Base scenario (i.e., base "with transaction") vs. Status Quo Forecast scenario, as shown in Table 1 below. These savings reflect the sustainable efficiencies and synergies achieved through HOSSM's integration with Hydro One, as actual OM&A expenses have trended lower. This declining trend is also reflected in HOSSM's cost control scorecard metrics (see TSP Section 2.10 Attachment 3: OM&A Per Gross Fixed Asset Value).

HOSSM has completed transmission total cost benchmarking, which indicates that its transmission costs have been below benchmark expectations over the last decade.[2] These results demonstrate that HOSSM has maintained efficient cost performance while continuing to deliver safe and reliable service.

HOSSM has completed OEB Appendices 2-JA, 2-JB, 2-JC and 2-L in Attachment 1.

[2] Exhibit A-04-01 Attachment 1, Section 4.5.

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Table 1 - HOSSM Summary of OM&A Expenses ($M)

Description	Historical Years											Bridge	Test Years		Section in this Exhibit
	2016	2016**	2017**	2018**	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
	OEB Approved	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast	
Sustainment					7.2	7.9	8.0	8.0	7.1	7.2	7.0	8.4	8.5	9.1	3.0
Common and Other*					3.7	2.1	1.7	1.3	1.9	2.2	2.2	2.4	2.1	1.8	4.0
Total	**11.4**[3]	**11.1**	**9.4**	**9.1**	**10.9**	**10.1**	**9.7**	**9.3**	**9.1**	**9.4**	**9.2**	**10.8**	**10.6**	**10.9**	2.0
MAADS Status Quo Forecast[4]		n/a	11.5	11.7	11.9	12.2	12.4	12.7	12.9	13.2	13.4	13.7	n/a	n/a	1.0
Status Quo Savings from Acquisition		**n/a**	**2.1**	**2.6**	**1.0**	**2.1**	**2.7**	**3.4**	**3.8**	**3.8**	**4.2**	**2.9**	**n/a**	**n/a**	
MAADS Base Forecast[5]		n/a	11.5	11.7	10.7	11.0	11.2	11.4	11.6	11.4	11.6	11.8	n/a	n/a	
Base vs Status Quo Savings		**n/a**	**0.0**	**0.0**	**1.2**	**1.2**	**1.2**	**1.3**	**1.3**	**1.8**	**1.8**	**1.9**	**n/a**	**n/a**	

** This includes Common Corporate Functions & Services (CCF&S), Asset Management (Planning), Digital & Technology Solutions (DTS), Operations, and Other OM&A*
*** Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.*

[3] EB-2014-0238, Decision, December 18, 2014, Great Lakes Power Transmission Rate Application for 2015 and 2016 rates, Appendix A-1, p.19 of $11.1M, and $0.2M for Property Taxes, with rounding equals $11.4M.
[4] EB-2016-0050, Exhibit A-02-01 – Table 4.
[5] EB-2016-0050, Exhibit A-02-01 – Table 5.

2.0 ENVELOPE LEVEL VARIANCE EXPLANATIONS

This section briefly addresses envelope level variance explanations, which are further described in the sections that follow.

2.1 COMPARISON OF THE 2027 AND 2028 TEST YEAR OM&A TO 2016 OEB-APPROVED

The 2027 and 2028 Test Year OM&A of $10.6M and $10.9M, respectively, are $0.8M (or 7%) and $0.5M (or 4%) lower, respectively, than HOSSM's last OEB-approved OM&A of $11.4M[6] for 2016. HOSSM's 2016 OM&A was established in 2014, before it was acquired by Hydro One Inc. and has been in a deferred rebasing period since the transaction was approved in 2016.

The key driver of lower 2027 and 2028 Test Year OM&A compared to HOSSM's last OEB-approved OM&A is the Common and Other OM&A category. The operational integration of HOSSM with Hydro One has resulted in access to specialized resources and expertise, and standardized business processes, delivered by Hydro One. These efficiencies help reduce duplication and enable asset and system needs to continue to be addressed in a cost-effective manner.

Through HOSSM's operational integration into Hydro One, savings from efficiency and synergies have allowed HOSSM to propose 2027 and 2028 Test Year OM&A amounts that are lower than the prior OEB-approved OM&A, notwithstanding accumulated inflation over the 10-year deferred rebasing period that affects underlying costs.

2.2 COMPARISON OF THE 2027 AND 2028 TEST YEAR OM&A TO 2025 ACTUAL OM&A (MOST RECENT ACTUALS)

Compared to 2025 actual OM&A of $9.2M, HOSSM's 2027 and 2028 Test Year OM&A of $10.6M and $10.9M, respectively, are $1.4M and $1.7M higher, respectively. This

[6] EB-2014-0238, Decision, December 18, 2014, Great Lakes Power Transmission Rate Application for 2015 and 2016 rates, Appendix A-1, p.19 of $11.1M, and $0.2M for Property Taxes, with rounding equals $11.4M.

increase is driven by the proposed maintenance activities described below and the effects of inflation on underlying costs:

- Station Equipment Maintenance increases in the Test Years to mitigate operational risks, maintain system reliability, and enhance condition assessment efforts, as discussed in Section 3.0;
- Telecom Maintenance increases as HOSSM migrates telecom monitoring and control to provide telecom services and functionality comparable to those supporting Hydro One's transmission system, as discussed in Section 3.0;
- Vegetation Management decreases due to more work being completed in 2025 due to the cyclical nature of work, as discussed in Section 3.0; and
- Other OM&A decreases due to lower allocation rate, as discussed in Section 4.0.

2.3 COMPARISON OF THE 2016 TO 2025 ACTUAL OM&A TO 2016 OEB-APPROVED

Compared to the 2016 OEB approved OM&A of $11.4M, HOSSM's average actual OM&A over the 2016-2025 period was $9.7M, which is $1.7M lower than the 2016 OEB approved amount. The main drivers for lower OM&A are discussed in Section 2.1 above (i.e., sustainable efficiencies), which were offset by increased spending on Stations and Lines Sustainment OM&A over the 2019-2025 period.

3.0 SUSTAINMENT OM&A

Transmission Sustainment OM&A consists of expenses required to maintain existing transmission system equipment and facilities to ensure they continue to function safely and as originally designed.

Table 2 below sets out HOSSM's Sustainment OM&A for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[7]. As this work is planned and completed by Hydro One, detailed descriptions of it may be found in Exhibit E-02-02, Section 2.2.

[7] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

Table 2 - HOSSM - Summary of Sustainment OM&A ($M)[8]

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Stations	3.8	4.3	4.1	4.3	4.5	5.6	4.4	6.1	6.1	6.5
Lines	3.4	3.5	3.9	3.7	2.6	1.5	2.6	2.2	2.3	2.4
Engineering & Environmental Support	0.0	0.1	0.0*	0.0*	0.1	0.1	0.1	0.1	0.1	0.2
Total Sustainment	**7.2**	**7.9**	**8.0**	**8.0**	**7.1**	**7.2**	**7.0**	**8.4**	**8.5**	**9.1**

** Values are less than $50k*

HOSSM's Sustainment OM&A for the 2027 and 2028 Test Years are $8.5M and $9.1M, respectively, representing a $1.3M and $1.9M increase over 2019 actuals, respectively and a $1.0M and $1.4M increase over the average of the last rate period (2019-2026), respectively.

3.1 TOP DRIVERS OF THE 2027 AND 2028 SUSTAINMENT OM&A

The principal drivers of the 2027 and 2028 Test Year OM&A relative to the historical period are described below.

Station Equipment Maintenance OM&A – HOSSM will continue to carry out routine maintenance activities that are critical for identifying and correcting equipment deficiencies while collecting asset condition data. Maintenance levels are increasing over the Test Years to further mitigate operational risks, maintain system reliability, and enhance condition assessment efforts. The condition data will support the identification and prioritization of assets requiring replacement.

Protection, Automation and Telecom Maintenance OM&A – HOSSM will continue to maintain its protection and automation equipment which are required to protect, control, and operate the transmission system. In the 2026 Bridge Year HOSSM will migrate its

[8] Figures presented in the tables may not sum to the totals shown due to rounding.

telecom monitoring and control to provide comparable telecom services and functionality to those supporting Hydro One's transmission system.

Vegetation Management – HOSSM carries out brush control and line clearing across its rights-of-way to ensure they are compliant with NERC's FAC-003 Transmission Vegetation Management standards and to maintain the clearance distance between energized equipment and the vegetation. This maintenance is completed on six and eight-year cycles. Vegetation Management expenses decline into the Test Years due to lower activity levels with the next peak work period beginning in 2030 according to HOSSM's vegetation management cycle.

3.2 STATIONS SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide further detail on the Stations Sustainment OM&A categories, including the related programs and sub-programs, Test Year expenses, and variance analysis.

Transmission stations are used for the delivery of power, voltage transformation, and switching. They serve as connection points for both load customers and generator customers. Transmission stations contain power system equipment further described in TSP Section 2.2.

The Stations Sustainment OM&A covers expenses that maintain the performance of assets located within HOSSM's transmission stations. The Stations Sustainment OM&A program is divided into the following program categories: (i) Environmental Management; (ii) Station Equipment Maintenance; (iii) Protection, Automation and Telecom Maintenance; and (iv) Site Infrastructure Maintenance. As this work is planned and completed by Hydro One, detailed descriptions of it may be found in Exhibit E-02-02, Section 2.2.

3.2.1 STATIONS SUSTAINMENT OM&A

Table 3 below sets out HOSSM's Stations Sustainment OM&A for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[9].

Table 3 - HOSSM Stations Sustainment OM&A ($M)

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Environmental Management	0.2	0.3	0.5	0.6	0.2	0.3	0.3	0.4	0.4	0.4
Station Equipment Maintenance	0.7	1.0	0.8	1.0	1.2	1.4	1.0	1.2	1.3	1.6
Protection, Automation and Telecom Maintenance	0.4	0.4	0.5	0.5	0.6	0.9	0.9	1.4	1.3	1.4
Site Infrastructure Maintenance	2.6	2.6	2.4	2.2	2.5	3.0	2.2	3.1	3.1	3.2
Total	**3.8**	**4.3**	**4.1**	**4.3**	**4.5**	**5.6**	**4.4**	**6.1**	**6.1**	**6.5**

HOSSM's Station Sustainment OM&A for the 2027 and 2028 Test Years are $6.1M and $6.5M, respectively, representing a $2.3M and $2.7M increase over 2019 actuals, respectively and a $1.5M and $1.9M increase over the average of the last rate period (2019-2026), respectively.

The 2027 and 2028 Test Year OM&A are primarily driven by increasing expenses for Station Equipment Preventive and Corrective Maintenance, which identifies and corrects equipment deficiencies and collects condition data to identify and prioritize assets that need to be replaced; rising expenses on Protection, Automation and Telecom Maintenance as HOSSM migrates its telecom monitoring and control to provide comparable telecom services and functionality as those supporting Hydro One's transmission system; and increasing property taxes and maintenance expenses for

[9] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

Facilities Infrastructure, which ensures aging facilities continue to be fit for purpose, by addressing the operational and maintenance needs.

3.2.1.1 ENVIRONMENTAL MANAGEMENT

HOSSM's Environmental Management program supports environmental compliance and risk mitigation at its transmission station sites through the inspection, monitoring, and maintenance of environmental protection systems and controls. These activities help protect employees, the public, the environment, and the reliability of the transmission system. Further information may be found in Exhibit E-02-02 Section 2.2.2.

HOSSM's Environmental Management OM&A for the 2027 and 2028 Test Years are $0.4M and $0.4M, respectively, representing a $0.2M increase over 2019 actuals, and a $0.1M increase over the average of the last rate period (2019-2026).

3.2.1.2 STATION EQUIPMENT MAINTENANCE

HOSSM's Station Equipment Maintenance program maintains its fleet of transmission assets including 16 transformers, 107 circuit breakers, as well as switches, insulators, bus work, instrument transformers, capacitor banks, reactors, and ancillary equipment (including NERC mandated DC system maintenance) installed in 15 transmission stations. Maintenance of these assets is required to sustain power equipment performance and to maintain transmission system safety and reliability, refurbish power equipment to preserve the equipment's expected service life and reliability, and assess poor-equipment condition warranting replacement under HOSSM's capital renewal plan.

The Station Equipment Maintenance program is divided into the following categories: (i) Preventive Maintenance, and (ii) Corrective Maintenance. As this work is planned and completed by Hydro One, detailed descriptions of it may be found in Exhibit E-02-02 Section 2.2.3.

Table 4 below sets out HOSSM's Station Equipment Maintenance expenses for the Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[10].

Table 4 - HOSSM Station Equipment Maintenance OM&A ($M)

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Preventive Maintenance	0.5	0.4	0.4	0.5	0.7	0.6	0.7	0.6	0.6	0.8
Corrective Maintenance	0.2	0.6	0.4	0.5	0.5	0.8	0.3	0.6	0.6	0.8
Total	**0.7**	**1.0**	**0.8**	**1.0**	**1.2**	**1.4**	**1.0**	**1.2**	**1.3**	**1.6**

HOSSM's Station Equipment Maintenance OM&A for the 2027 and 2028 Test Years are $1.3M and $1.6M, respectively, representing a $0.6M and $0.9M increase over 2019 actuals, respectively, and a $0.2M and $0.6M increase over the average of the last rate period (2019-2026), respectively.

The 2027 and 2028 Test Year OM&A are primarily driven by increasing expenses for Preventive and Corrective Maintenance (e.g., breaker/transformer/switch/ancillary diagnostics, intrusive maintenance) that will identify and correct equipment deficiencies and collect condition data to assess the need for, prioritize, and execute new replacement candidates that may arise.

3.2.1.3 PROTECTION, AUTOMATION AND TELECOM MAINTENANCE

Protection and automation assets are required to protect, control, and operate the transmission system. They also provide real-time operational data, control remote equipment, and capture detailed event records for post-event analysis. Power system telecom systems (PSTS) provide high-reliability and high-speed communications required for the protection, monitoring, and control of HOSSM's transmission system. The

[10] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

Protection, Automation program is divided into the following categories: (i) Preventive Maintenance, (ii) Corrective Maintenance, and (iii) Support Processes and Systems programs, and the Power System Telecom program is divided into three categories: (i) Preventive and Corrective Maintenance; (ii) Leased Telecommunication Circuits for PSTS; and (iii) Operation of PSTS. As this work is planned and completed by Hydro One, detailed descriptions of it may be found in Exhibit E-02-02, Section 2.2.5.

Table 5 below sets out HOSSM's Protection, Automation and Telecom expenses for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[11].

Table 5 - HOSSM Protection, Automation and Telecom OM&A ($M)

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Protection and Automation	0.2	0.2	0.2	0.3	0.3	0.4	0.6	0.5	0.4	0.4
Telecom	0.2	0.3	0.3	0.2	0.3	0.4	0.3	0.9	0.9	0.9
Total	**0.4**	**0.4**	**0.5**	**0.5**	**0.6**	**0.9**	**0.9**	**1.4**	**1.3**	**1.4**

HOSSM's Protection, Automation and Telecom expenses for the 2027 and 2028 Test Years are $1.4M and $1.4M, respectively, representing a $1.0M increase over 2019 actuals, and a $0.7M increase over the average of the last rate period (2019-2026).

The 2027 and 2028 Test Year expenses are higher than the historical average as Telecom service expenses increase in the Bridge Year as HOSSM migrates its telecom monitoring and control to provide comparable telecom services and functionality as those supporting Hydro One's transmission system.

[11] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

3.2.1.4 SITE INFRASTRUCTURE MAINTENANCE

HOSSM's site and infrastructure systems are comprised of structural, building shell, roofing, HVAC, water and sewage management, elevators, interior fixtures, access roads, yard drainage and siteworks at transmission stations. These systems provide infrastructure and support services to other station components, prevent unauthorized access, and make the station site functional for equipment and staff.

The Site Infrastructure Maintenance program carries out planned and corrective maintenance at HOSSM's transmission stations to ensure that these site facilities and infrastructure systems remain safe and in a state of good repair.

Table 6 below sets out HOSSM's Site Infrastructure Maintenance OM&A for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[12].

Table 6 - HOSSM Site Infrastructure Maintenance OM&A ($M)

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Site Infrastructure Maintenance	2.6	2.6	2.4	2.2	2.5	3.0	2.2	3.1	3.1	3.2

HOSSM's Site Infrastructure Maintenance OM&A for the 2027 and 2028 Test Years are $3.1M and $3.2M, respectively, representing a $0.5M and $0.6M increase over 2019 actuals, respectively, and a $0.5M and $0.6M increase over the average of the last rate period (2019-2026), respectively.

The 2027 and 2028 Test Year OM&A are in line with the 2026 Bridge Year and are increasing relative to the historical years. These expenses are required to ensure an aging

[12] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

facility continues to be fit for purpose, and to meet operational and maintenance needs for HOSSM's facilities.

3.3 LINES SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide further details regarding Lines Sustainment categories, the respective programs and sub-programs, Test Year expenses and variance analysis.

The high-voltage power lines in HOSSM's transmission network are categorized as either lines that form part of the BES or area supply lines. Power lines which form part of the BES typically connect major generation facilities with transmission stations and often cover long distances, while area supply lines serve a local region.

HOSSM's transmission lines primarily operate at voltages of 230 kV and 115 kV, with minor lengths (approx. 11 circuit-km) operating at 44kV. HOSSM's transmission system consists of approximately 554 circuit-km of overhead transmission lines located on about 1,738 hectares of rights-of-way and no underground transmission lines.

Overhead transmission line components include structures (primarily steel or wood) and corresponding foundations, conductors, shield wire, insulators, lightning arrestors, hardware, switches, and grounding systems.

Lines Sustainment OM&A covers expenses required to maintain existing overhead transmission lines assets. HOSSM's Lines Sustainment OM&A program is divided into the following categories: (i) Vegetation Management, and (ii) Overhead Lines Maintenance. As this work is planned and completed by Hydro One, detailed descriptions of it may be found in Exhibit E-02-02, Section 3.1.

3.3.1 LINES SUSTAINMENT OM&A

Table 7 below sets out HOSSM's Lines Sustainment OM&A for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[13].

Table 7 - HOSSM Lines Sustainment OM&A ($M)

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Vegetation Management	2.8	3.0	3.5	3.2	2.2	1.2	2.1	1.7	1.7	1.7
Overhead Lines Maintenance	0.4	0.4	0.4	0.4	0.3	0.3	0.5	0.5	0.6	0.6
Other*	0.1	0.1	0.0*	0.1	0.0*	0.0	0.0	0.0*	0.0*	0.1
Total	**3.4**	**3.5**	**3.9**	**3.7**	**2.6**	**1.5**	**2.6**	**2.2**	**2.3**	**2.4**

**Values are less than $50k*

HOSSM's Lines Sustainment OM&A for the 2027 and 2028 Test Years are $2.3M and $2.4M, respectively, representing a $1.1M and $1.0M decrease over 2019 actuals, respectively, and a $0.7M and $0.6M decrease over the average of the last rate period (2019-2026), respectively.

The 2027 and 2028 Test Year OM&A are primarily driven by increasing Overhead Lines Maintenance expenses to address approximately 100 accumulated low-priority defects in addition to the regular work program. This work is required to mitigate identified asset condition issues and maintain transmission line reliability. These higher costs are offset by lower Vegetation Management expenses due to lower activity levels in the Test Years with the next peak work period beginning in 2030 according to HOSSM's vegetation management cycle.

[13] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

3.3.1.1 VEGETATION MANAGEMENT

The strip of land that is occupied by a transmission line is referred to as a right-of-way (ROW) or a corridor. HOSSM's in-service ROWs cover an area of approximately 1,738 hectares and support its 230 kV circuits and 115 kV circuits.

HOSSM's 230kV circuits form part of the Bulk Electric System and are therefore subject to NERC's FAC-003 Transmission Vegetation Management standards. These require HOSSM to improve the reliability of its transmission systems by preventing outages from vegetation located on transmission ROWs, minimizing outages from vegetation located adjacent to ROWs, and maintaining clearances between transmission lines and vegetation on and along transmission ROWs. To ensure system reliability and compliance with NERC's FAC-003, the Vegetation Management program is responsible for maintaining the clearance distance between the energized equipment and the vegetation located on and adjacent to all of these ROWs.

The Vegetation Management program consists of the following categories: (i) brush control, (ii) line clearing, (iii) virtual patrol, (iv) property owner notifications, (v) annual vegetation patrol, (vi) grounds maintenance, and (vii) demand (unplanned) maintenance. Brush control and line clearing are the program's major cyclical activities and are completed on six and eight-year cycles.

HOSSM's Vegetation Management OM&A for the 2027 and 2028 Test Years are $1.7M and $1.7M, respectively, representing a $1.1M decrease over 2019 actuals, and a $0.8M decrease over the average of the last rate period (2019-2026), respectively.

Expenses in 2027 and 2028 are lower than the historical average because HOSSM's vegetation management program is planned on six and eight-year cycles. More vegetation work was completed in the years immediately following integration with Hydro One to bring the ROWs to standard, while the next peak work period begins in 2030 under the eight-year cycle. As a result, the 2027 and 2028 Test Years reflect lower activity levels, and any

higher vegetation management costs during the rate period will be managed within HOSSM's overall OM&A envelope.

3.3.1.2 OVERHEAD LINES MAINTENANCE

The Overhead Lines Maintenance program is required to maintain the reliability of its transmission lines, address safety issues, and ensure the long-term economic viability of the overhead lines system. The program includes activities such as overhead lines inspections to identify defects, component condition assessments to identify poor-condition assets that will require replacement, planned corrective maintenance to replace and repair minor components, and demand maintenance to respond to emergency and high-priority situations. The gathering of asset condition information enables HOSSM to allocate funding based on priority to maximize the life of the lines assets and to maintain asset performance. The program also provides for repair or replacement of defective equipment and components.

The Overhead Lines Maintenance program is divided into the following activities: (i) Preventive Maintenance and Asset Assessment, (ii) Demand Maintenance, and (iii) Planned Corrective Maintenance.

HOSSM's Overhead Lines Maintenance OM&A for the 2027 and 2028 Test Years are $0.6M and $0.6M, respectively, representing a $0.2M increase over 2019 actuals, and a $0.2M increase over the average of the last rate period (2019-2026).

Expenses in the Test Years are higher than the historical average to address approximately 100 accumulated low-priority defects over the rate period in addition to the regular work program. This work is required to mitigate identified asset condition issues and maintain transmission line reliability.

3.4 ENGINEERING AND ENVIRONMENTAL SUPPORT

The sections below provide further details regarding Engineering and Environmental Support Sustainment category.

The Engineering and Environmental Support program supports a wide range of activities, including management of records and drawings, database management and provision of specific technical information, technical support including specialized studies, outage assessments conducted by the IESO, event investigation and incidents response, and funding of external technical expertise when needed.

This program is primarily demand-driven, in that it is driven by the level of work required to support the transmission capital work programs. The technical support and specialized studies are completed on an *ad hoc* basis to aid in the decision-making process and justification for capital investments.

Table 8 sets out sets out HOSSM's Engineering and Environmental Support OM&A for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[14].

HOSSM's Engineering and Environmental Support OM&A for the 2027 and 2028 Test Years are $0.1M and $0.2M, respectively and are in line with recent historical actuals.

Table 8 - HOSSM Engineering and Environmental Support OM&A ($M)

Description	Historical Years							Bridge	Test Years	
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast
Engineering & Environmental Support	0.0	0.1	0.0*	0.0*	0.1	0.1	0.1	0.1	0.1	0.2

** Values are less than $50k*

[14] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

4.0 COMMON AND OTHER OM&A

Hydro One's Common and Other OM&A are incurred to provide service on a shared basis to Hydro One and its affiliate companies. HOSSM's share of the common corporate functions OM&A are allocated to it through a cost allocation methodology which is described in Exhibit E-04-08

Table 9 below sets out HOSSM's Common and Other OM&A for the 2027 and 2028 Test Years, along with the forecast and actual expenses for the Bridge and Historical Years since integration with Hydro One (2019-2026)[15]. Since these services are provided on a shared basis with Hydro One, detailed descriptions of them may be found in the Exhibit references provided in Table 9.

HOSSM's Common and Other OM&A for the 2027 and 2028 Test Years are $2.1M and $1.8M, respectively, representing a $1.6M and $1.9M decrease over 2019 actuals, respectively, and a $0.1M and $0.4M decrease over the average of the last rate period (2019-2026), respectively.

Over the 2019-2026 period, Common and Other OM&A have declined as a result of the integration of HOSSM into Hydro One and the realization of sustainable efficiencies through access to specialized resources and expertise and standardized business processes delivered by Hydro One. These efficiencies help reduce duplication and enable asset and system needs to continue to be addressed in a cost-effective manner. Additional savings resulted from eliminating the former HOSSM control centre function and reducing IT procurement, maintenance and licensing costs.

The 2027 and 2028 Test Year OM&A are primarily driven by increasing expenses for Common Corporate Functions & Services due to the cumulative impact of several non-material increases within Common Corporate Functions & Services mainly driven by the

[15] Since HOSSM was operationally integrated in late-2018, 2019 reflects the first full year under Hydro One.

allocation of Corporate Affairs, General Counsel and Regulatory services, and partly offset by lower allocated Planning and Other OM&A in 2028.

Table 9 - HOSSM Common and Other OM&A ($M)

Description	Historical Years							Bridge	Test Years		Exhibit Reference
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	F/cast	F/cast	F/cast	
Common Corporate Functions & Services (CCF&S)	1.5	0.7	0.4	0.4	0.6	0.4	0.6	0.7	0.7	0.9	E-04-02
Planning	0.2	0.2	0.2	0.2	0.2	0.2	0.1	0.3	0.3	0.1	E-04-03
Digital & Technology Solutions	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*	E-04-04
Operations	1.0	1.0	0.3	0.2	0.2	0.3	0.2	0.3	0.3	0.3	E-04-05
Other OM&A[16]	1.1	0.2	0.8	0.5	1.0	1.3	1.3	1.1	0.8	0.6	
Total	**3.7**	**2.1**	**1.7**	**1.3**	**1.9**	**2.2**	**2.2**	**2.4**	**2.1**	**1.8**	

** Values are less than $50k*

5.0 O&M WORK EXECUTION STRATEGY

Since Hydro One has operationally integrated HOSSM and there are no HOSSM employees, O&M work is executed by Hydro One Transmission as discussed in Exhibit E-02-05.

[16] Other Costs include adjustments to provisions, inventory adjustments, project write-offs, and accounting adjustments.

CHAPTER 2 APPENDIX 2-JA, 2-JB, 2-JC, AND 2L - HOSSM OM&A EXPENDITURES

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SUMMARY OF DISTRIBUTION OM&A EXPENDITURES

1.0 INTRODUCTION

This Exhibit summarizes Hydro One Distribution's Operations, Maintenance and Administration (OM&A) expenditures over the 2023 to 2028 planning period including comparisons between 2023 to 2026,[1] the 2027 bridge year, and the 2028 test year.[2]

The Distribution OM&A plan is comprised of five categories: (i) Sustainment, (ii) Development, (iii) Customer Care, (iv) Common and Other, and (v) Property Taxes and Rights Payments. This exhibit addresses the first three categories, Exhibit E-04-01 addresses Common and Other OM&A, and Exhibit E-09-06 addresses Property Taxes and Rights Payments.

During 2023 and 2024, Hydro One faced market cost pressures, higher demand-driven work volumes, extreme weather, environmental compliance obligations, and evolving security needs. In response, Hydro One prioritized mandatory, safety-critical, customer service, and regulatory compliance activities, along with increased security expenditures. These conditions required the company to manage its OM&A spending within the overall funding available for the five-year custom incentive rate-making (IR) term.

To address the challenges experienced in the early years of the current rate period, Hydro One implemented additional productivity and cost control measures, including a company-wide cost optimization program, as discussed in SPF Section 1.4.3.2. Hydro One also reduced, deferred, or re-paced certain planned work, where doing so would not create unacceptable near-term reliability, compliance or customer service risk. These actions enabled Hydro One to manage the higher expenditures required earlier in the rate period and bring cumulative OM&A spending closer to the total rates funding over the five-year period.

[1] Includes actual expenditures for 2023-2025 and forecast expenditures for 2026.
[2] 2029 to 2032 OM&A is established mechanistically, using an index-based approach, in accordance with the Custom IR framework described in Exhibits A-04-01 and A-04-03.

Witness: Paul Ankrett, Peter Faltaous, Spencer Gill, Kevin Marcotte, Anthony Nava, Aimee Oabel, David Paish

Hydro One remains committed to managing OM&A expenditures through productivity improvements, cost control measures, and prudent spending controls, such that cumulative OM&A expenditures over the five-year period remain close to total funding available. Consistent with commitments established during the 2023 planning process, the 2026 and 2027 plan includes cost containment measures of $17.0M and $37.0M, as reflected in Table 1. These measures reflect ongoing management actions to contain costs while maintaining safe, reliable, and customer-focused service delivery.

These combined measures helped Hydro One manage market-cost pressures, demand-driven work volumes, and emerging operating requirements, while containing spending close to the OEB-approved funding envelope during the 2023-2027 period. However, reliance on cost containment, reprioritization, and the deferral or re-pacing of planned work cannot be sustained indefinitely. Vegetation continues to grow, asset defects accumulate, customer expectations continue to evolve, and the distribution system must support a materially larger capital program to accommodate increasing distributed energy resource (DER) adoption, load growth driven by electrification, and greater exposure to severe weather events.

Accordingly, Hydro One's 2028 OM&A plan reflects a transition from short-term reprioritization to a sustainable operating model. The proposed expenditures are required to restore sustainable maintenance levels, support execution of the capital plan described in DSP Section 3.1, strengthen system reliability and resilience, and maintain secure, reliable, and customer-focused distribution service. The plan also positions Hydro One to meet the evolving needs of customers while prudently managing the long-term condition and performance of its distribution system.

1.1 BACKGROUND FOR VARIANCE EXPLANATIONS

The variance analyses in this exhibit are meant to assist the OEB in assessing Hydro One’s Distribution OM&A requirements in the context of the current rate period and the 2028 test year. The analyses compare 2023 actuals to the 2023 OEB-approved amount at the envelope level. Variance explanations at the category, project, or program level are

based on filed program-level evidence in EB-2021-0110, adjusted for inflation and the proportionate application of approved settlement reductions (referred to as 'planned expenditure levels' in this exhibit). These are notional values because the approved settlement reductions were applied only at the OM&A envelope level for 2023, not allocated to specific categories, projects, or programs.

Hydro One provides variance explanations relative to the 2023 to 2027 annual average, as it offers a more representative basis for assessing 2028 variances than any individual year in isolation. As discussed in Section 1.0, Hydro One incurred higher costs in 2023 and 2024 to address demand-driven work, market cost pressures, and mandatory requirements, and subsequently reduced spending through productivity initiatives, cost control measures, and the selective deferral or re-pacing of certain planned activities. The annual average therefore reflects Hydro One's management of OM&A over the full five-year rate period.

1.2 DISTRIBUTION OM&A FORECAST OVERVIEW

The Distribution OM&A forecast for the 2028 test year aligns with the investment needs and drivers identified in the Distribution System Plan (DSP Section 3.1) and the Business Plan (Exhibit A-03-01, Attachment 1). Hydro One's Distribution OM&A expenditures for the historic, bridge and test years are provided in Table 1 below.

Table 1 - Summary of Recoverable Distribution OM&A Expenses ($M)[3]

Distribution	Historical					Bridge	Test
	2023	2023	2024	2025	2026	2027	2028
	OEB-Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment		366.2	365.9	319.3	359.4	358.2	523.0
Development		9.5	10.0	10.6	12.4	12.4	17.6
Customer Care		94.8	106.7	102.1	115.9	120.0	139.6
Common and Other OM&A [1]		200.1	220.7	193.9	181.4	186.3	271.1
Property Taxes		6.2	5.8	6.4	6.7	7.0	7.5
Cost Containment Efforts					-17.0	-37.0	
Total	**616.3**	**676.8**	**709.1**	**632.4**	**658.9**	**646.9**	**958.7**

[1] This includes Common Corporate Functions & Services (CCF&S), Asset Management (planning) costs, Digital & Technology Solutions (DTS), Operations, and Cost of Sales for external work & Other OM&A

Hydro One Distribution is proposing an OM&A forecast of $958.7M for the 2028 test year. This is an increase of $342.4M relative to the 2023 OEB-approved amount in EB-2021-0110, $281.9M relative to 2023 actual expenditures, and $293.9M relative to the 2023-2027 average annual expenditures.

To distinguish the effects of inflation from changes in underlying OM&A requirements, Table 2 isolates the impact of inflation by comparing the 2028 OM&A proposal to the 2023 OEB-approved OM&A amount escalated annually using the applicable I-X factors.[4]

[3] Rounded figures within tables may not sum precisely due to rounding.
[4] Where I represents the annual OEB inflation factor, and X represents the productivity factor of 0.45% as approved in EB-2021-0110.

Table 2 - Comparison of 2028 Test Year OM&A to I-X Escalated 2023 OEB-Approved OM&A ($M)

Distribution OM&A	Amount ($M)	%
2023 OEB-approved OM&A	616.3	
I-X escalation from 2023 to 2028	104.0	
2023 OEB-approved OM&A escalated to 2028 using I-X *[1]*	720.3	
2028 Test Year OM&A	958.7	
Variance to 2028 Test Year OM&A	+238.4	33.1%

[1] OEB inflation is assumed to be 2.9% in both 2027 and 2028.

As shown in Table 2, this results in an I-X-escalated 2028 benchmark of $720.3M. Comparing the 2028 OM&A proposal to this benchmark provides context for assessing changes in underlying OM&A requirements, net of inflationary impacts over the period. The 2028 OM&A proposal of $958.7M is $238.4M, or 33.1%, above the I-X-escalated benchmark.

The comparison demonstrates that a significant portion of the 2028 funding requirement is attributable to inflationary pressure on the underlying OM&A cost base before considering changes in underlying work requirements. Hydro One's proposed 2028 Distribution OM&A of $958.7M reflects the inflation-adjusted cost base established through the current rate period, together with the incremental funding required to restore sustainable maintenance levels and address increasing system needs.

This concept is further illustrated in Figure 1, which provides additional context for understanding the increase between the 2023 OEB-approved OM&A amount and the 2028 OM&A proposal. The I-X escalated benchmark reflects the impact of inflationary adjustments over the current period, while the remaining increase above that benchmark reflects the funding required to support the transition from short-term reprioritization to a sustainable operating plan.

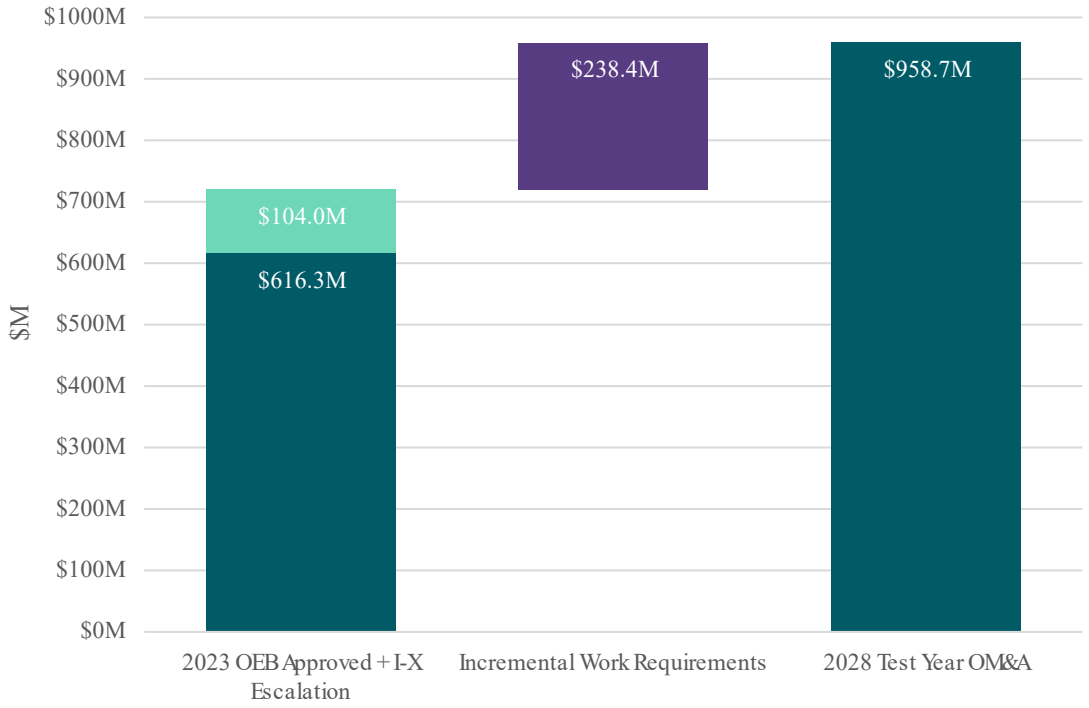


Figure 1: Increase Between the 2023 OEB-Approved OM&A Amount and the 2028 Test Year OM&A

2.0 DESCRIPTION OF OM&A CATEGORIES

This section includes a brief description of each of the OM&A work categories. Further detail is provided in the accompanying exhibits identified in Table 3.

Table 3 - Supporting OM&A Exhibits

Work Category	Exhibit Reference	Exhibit Title	Witness
Sustainment	E-03-02	Distribution Sustainment OM&A	Paul Ankrett, Aimee Oabel, David Paish, Kevin Marcotte
Development	E-03-03	Distribution Development OM&A	Peter Faltaous
Customer Care	E-03-04	Distribution Customer Care OM&A	Spencer Gill
Common and Other	E-04-01	Common and Other OM&A	Anthony Nava
Property Taxes and Rights Payments	E-09-06	Property Taxes and Rights Payments	Julie Ricketts Daniel

2.1 SUSTAINMENT

The Distribution Sustainment program maintains the performance, reliability, and safety of the distribution system through proactive inspection, maintenance, vegetation management, and operational support activities. The program also performs critical reactive work, including responding to trouble calls, customer requests, and asset failures, supporting customer service expectations and compliance with regulatory, legal, and policy requirements. Work is divided into five categories: (i) stations, (ii) lines, (iii) meters, telecom, protection and control, (iv) vegetation management, and (v) smart grid.

Over 2023–2025, the Sustainment program responded to approximately 49,000 trouble calls per year, completed over 248,000 cable locate requests annually, processed approximately 30,000 disconnect/reconnect requests, and cleared thousands of kilometres of rights of way through the Vegetation Management program.

2.2 DEVELOPMENT

The Distribution Development program connects load and generation customers, monitors distributed energy resources (DERs), establishes technical standards for power system assets, and monitors power quality for industrial customers. Development work is critical because it enables economic growth, supports electrification and clean energy objectives, and helps maintain a safe and reliable distribution system. Work is divided into five categories: (a) engineering and technical studies; (b) distributed generation connections support; (c) distribution standards programs; (d) research development and demonstration; and (e) customer power quality programs.

Over 2023–2025, the Development program provided analytical capabilities to assess system needs, conduct technical studies, and support the tools and processes used to inform distribution planning and investment decisions. The program also: supported the study, coordination, and sustainment of DER connections, including developing 398 connection cost estimates; maintained and updated core engineering and design standards to support emerging technologies; and advanced research to inform future capital planning and customer-driven investments across the distribution system.

2.3 CUSTOMER CARE

The Distribution Customer Care program supports Hydro One's 1.5 million customers. Hydro One's Customer Care OM&A funds the activities, resources, tools and programs required to support customer service delivery, billing and collections, customer account management and customer participation in emerging electricity sector initiatives. These programs include Customer Relations Management, Meter to Cash, Service Enhancements and DER Customer Enablement.

Over 2023-2025, the Customer Care program responded to customer calls, with call volumes increasing from 1.7 million in 2023 to over 2.1 million in 2025, driven in part by exogenous events, such as storms and the Canada Post labour disruption as described in DSP Section 3.5.2.2.3. The program also issued over 16.7 million bills each year, obtained meter readings, processed payments, managed the collections program, supported large customers through Hydro One’s dedicated account management team, and supported low-income customers with financial assistance through the OEB's Low-Income Energy Assistance Program (LEAP).

2.4 COMMON AND OTHER OM&A

Common Corporate OM&A expenditures are detailed in Exhibit E-04-01 and include Common Corporate Functions & Services (CCF&S), Planning, Digital and Technology Services (DTS), Operations, and other common support functions. These activities provide the enterprise capabilities required to operate and support the distribution business, including planning, operations, cyber and physical security, technology modernization, data and analytics, corporate services, and shared operational support. This cost category also captures Other OM&A costs, including the cost of sales incurred by Hydro One Distribution, as described in Exhibit E-04-07, and other corporate adjustments and cost recoveries, as described in E-04-02.

Common and Other OM&A expenditures are responsive to the needs of an evolving distribution system, which requires increasingly robust enterprise capabilities. Hydro One must operate a larger and more complex grid, support higher capital work volumes,

improve data and system visibility, respond to electrification and DER integration, and maintain security capabilities commensurate with an evolving cyber and physical threat landscape. These expenditures support the safe, reliable and secure operation of Hydro One's distribution system and are further addressed in Exhibit E-04-01 and supporting Common and Other OM&A exhibits.

2.5 PROPERTY TAXES AND RIGHTS PAYMENTS

The Distribution OM&A envelope also includes property taxes and rights payments. Hydro One is subject to property taxes in accordance with the *Electricity Act, 1998*, the *Municipal Act, 2001*, and the *Assessment Act, 1990*. Hydro One also pays annual fees for the right to cross and/or occupy properties owned by third parties, such as railway companies and/or governmental bodies. These expenditures are discussed in Exhibit E-09-06.

3.0 DISTRIBUTION OM&A EXPENDITURES – VARIANCE ANALYSIS

The following sections discuss the key variances and expenditure trends for the Distribution OM&A programs over three time periods: (1) 2023 OEB-Approved versus 2023 actuals, (2) 2023 to 2027 historical and bridge years, and (3) the 2028 test year.

3.1 2023 OEB APPROVED VS. 2023 ACTUALS

In the last rebasing application, the OEB approved a 2023 test year Distribution OM&A envelope of $616.3M. Hydro One's actual OM&A expenditures in 2023 for Distribution were $676.8M, representing an upward variance of $60.5M, primarily driven by incremental expenditures in Sustainment and Common and Other OM&A. This section explains the key variance drivers within Sustainment and Common and Other OM&A expenditures allocated to Distribution.

In 2023, Hydro One faced significant incremental work requirements in its demand-driven Sustainment programs, as well as sector-wide cost pressures resulting from the significant increase in inflation following the COVID-19 pandemic. Several Sustainment OM&A programs were particularly affected by these challenges:

- **Trouble Calls:** Actual Trouble Call expenditures of $93.6M were $29.7M (46%) higher than the planned expenditure level of $63.9M, reflecting higher-than-forecast volumes of unplanned service interruptions resulting from line component failures and vegetation contact, and an increased number of storm days.
- **Disconnects/Reconnects:** Actual expenditures of $35.7M were $19.3M (118%) higher than the planned expenditure level of $16.4M, primarily driven by higher-than-expected customer demand after the 2022 Derecho.
- **Cable Locates:** Actual expenditures of $25.8M were $12.4M (93%) higher than the planned expenditure level of $13.4M, reflecting growing demand for underground cable locate requests, consistent with increased construction and development activity across the service territory.

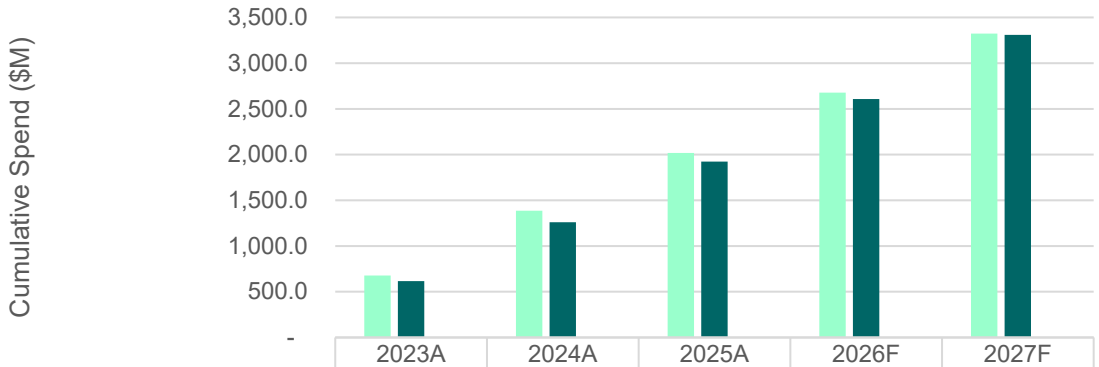
With respect to Common and Other OM&A, the increase was primarily driven by Hydro One's reprioritization of expenditures toward security-related activities in response to the evolving cyber threat landscape. In 2023, actual expenditures for DTS and Security Management were $109.3M and $4.5M, respectively. These amounts were $18.9M (21%) and $1.7M (61%) higher than their respective planned expenditure levels of $90.4M and $2.8M. Hydro One increased these expenditures to strengthen its ability to monitor, detect, and respond to potential vulnerabilities across its IT and OT environments, and to maintain the resilience and security of critical systems that support business and grid operations. Further details on Common Corporate OM&A are provided in Exhibit E-04-01.

To manage these challenges, Hydro One reprioritized work in other parts of its Sustainment plan. Most notably, in 2023, expenditures for the Vegetation Management and Lines Maintenance programs were reduced by approximately 15-20% relative to the planned expenditure levels to meet the requirements of the demand-based programs noted above. However, even with these prudent reprioritizations, Hydro One's Distribution OM&A expenditures in 2023 were $60.5M higher than the OEB-approved amount, requiring Hydro One to adjust its management of OM&A expenditures over the remainder of the 2023-2027 rate period.

3.2 2023 TO 2027 HISTORICAL AND BRIDGE YEARS

Hydro One's 2023 challenges continued throughout the rate period, with sustained growth in demand-driven work requirements and ongoing cost pressures across several Sustainment programs. Relative to planned expenditure levels, annual average expenditures for trouble calls, cable locates, and disconnects/reconnects were consistently and materially higher. Annual average expenditures on trouble calls were $90.2M, or $26.3M (41%) above plan. Cable locate expenditures averaged $28.8M, exceeding plan by $15.4M (115%), while disconnects/reconnects expenditures averaged $33.6M, or $17.2M (105%) above plan. These pressures reflected the realities of operating a large, geographically dispersed distribution system during a period of higher construction activity, customer growth, storm exposure, environmental compliance requirements, and inflationary cost escalation.

To manage these sustained pressures while maintaining service levels and addressing emerging operating requirements, Hydro One managed Distribution OM&A expenditures as a five-year funding envelope, balancing execution of planned work against total available funding over the rate term. This approach included further reprioritization of planned work and productivity improvements to mitigate rising costs. As a result, Hydro One is forecast to be materially aligned with total five-year Distribution OM&A funding by the end of 2027, with expenditures projected to exceed available funding by only $13.9M over the 2023-2027 period, as shown in Figure 2 below.



	2023A	2024A	2025A	2026F	2027F
Cumulative Expenditures	676.8	1,385.9	2,018.2	2,677.1	3,324.0
Cumulative OEB Approved	616.3	1,259.4	1,922.8	2,607.7	3,310.1
Variance	60.5	126.4	95.4	69.4	13.9

Figure 2: 2023 - 2027 Actual / Forecast Distribution OM&A vs OEB-Approved in Rates

This outcome reflects disciplined management. Hydro One absorbed higher demand-driven and inflation-related costs in the early years of the period, implemented additional cost control measures in the later years, and made trade-offs to defer certain planned work where risks could be managed in the short term. While these actions enabled Hydro One to manage expenditures prudently over the current rate period, they are not sustainable as a long-term operating strategy.

Hydro One employed two key strategies to manage its total OM&A expenditures during the current 2023-2027 rate period:

Trade-offs and reprioritization of planned work: Hydro One scaled back planned work in 2023-2025 that could be executed in the later years without jeopardizing immediate system outcomes, and reprioritized funding and resources to demand-driven programs experiencing sustained work volumes and cost pressures. Examples of this approach included reducing Right of Way (ROW) vegetation maintenance work from approximately 27,000 km annually during the first cycle of Optimal Cycle Protocol (OCP) (2018–2022) to an average of 11,500 km per year over 2023-2025, as well as reprioritizing planned corrective and preventive work in the Lines Maintenance program.

Witness: Paul Ankrett, Peter Faltaous, Spencer Gill, Kevin Marcotte, Anthony Nava, Aimee Oabel, David Paish

Productivity and cost control: In parallel, Hydro One implemented productivity measures over the 2023-2027 period to identify efficiencies and reduce costs required to achieve planned outcomes. From 2023-2025, Distribution OM&A programs have realized $125.2M in productivity savings, as described in SPF Section 1.4.3.2. Key examples include $42.4M from outsourcing PCB Inspect and Test activities, $31.8M from Forestry initiatives and $9.1M from the Customer Care eBilling initiative. Further initiative-level details are provided in SPF Section 1.4, Attachment 1. In addition to these productivity initiatives, Hydro One commenced an Enterprise Cost Optimization (ECO) Program during the current rate term to identify, develop and implement sustainable cost control measures. For Distribution OM&A, the ECO Program contributed savings of $17.0M in 2025, and planned savings of $13.1M in 2026, as discussed in SPF Section 1.4.3.2. In addition to these productivity and ECO Program savings, Hydro One has included cost containment measures of $17.0M and $37.0M in the plan forecast for 2026 and 2027 to reflect ongoing management actions to contain costs while maintaining safe, reliable, and customer-focused delivery of service.

3.3 2028 TEST YEAR INCREASES

The 2028 Test Year reflects a transition from short-term reprioritization to a more sustainable operating model. As discussed above, Hydro One managed the 2023-2027 period through selective deferral or re-pacing of planned work, but these measures are not sustainable over the longer term. The proposed 2028 expenditures restore sustainable maintenance levels, address deferred work, support execution of the larger capital plan described in DSP Section 3.1, and strengthen system reliability and resilience. They also respond to a fundamentally different operating environment characterized by higher input costs, growing customer and system demands, increasing electrification and DER activity, and the need for enhanced customer service, security, and technology capabilities.

In the 2028 test year, Distribution OM&A expenditures are forecast at $958.7M, an increase of $293.9M over the 2023 to 2027 annual average expenditures. This increase reflects the funding required to move from a period of short-term reprioritization and deferral to a sustainable operating plan for the next rate period. The primary drivers of the increase are as follows:

- restoring vegetation management and maintenance activities that were reduced during 2023 to 2027 to manage within the overall OM&A envelope;
- addressing higher unit costs caused by inflation, market cost pressures, and more complex field conditions;
- supporting the larger capital work program described in the DSP, including work execution, inspection, maintenance, outage, customer, and operational support required to deliver substantially higher capital volumes;
- responding to electrification, load growth, DER activity, and customer connection requirements;
- improving reliability and resilience as extreme weather becomes more frequent and severe;
- strengthening the technology, data, cyber, and security capabilities required to operate a modern electricity distributor; and
- maintaining customer service quality as interaction volumes and complexity increase, while supporting large customers, accurate billing and collections, customer affordability, and participation in emerging DER and energy programs.

Figure 3 illustrates the increase in Distribution OM&A expenditures from the 2023-2027 average to the 2028 Test Year forecast by OM&A category.

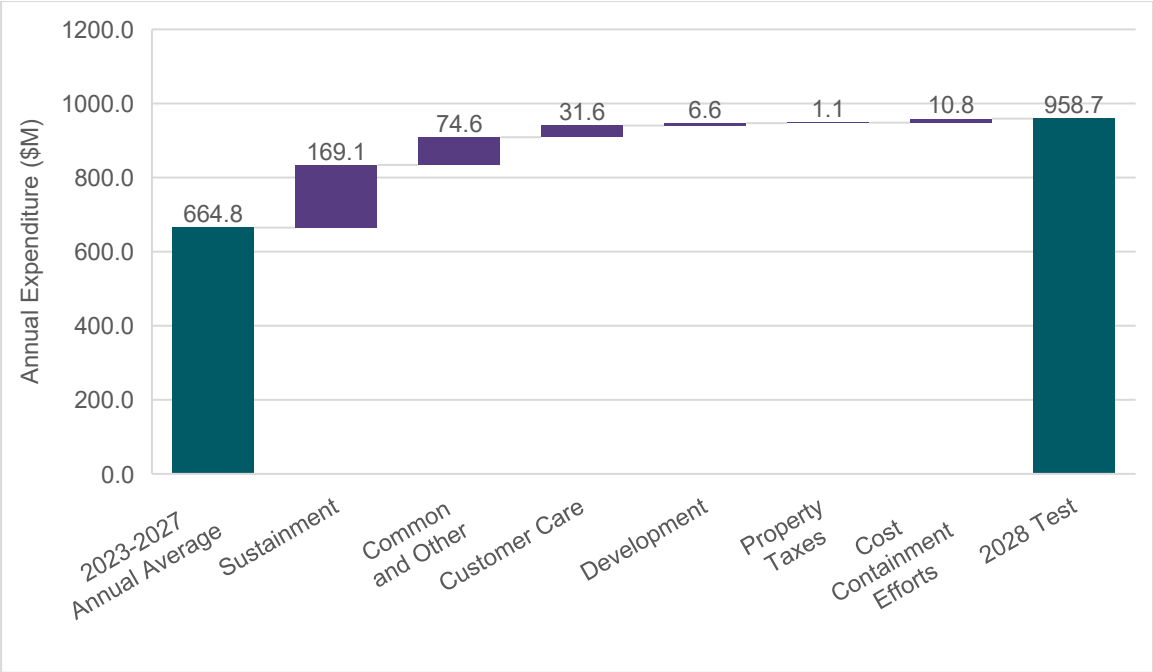


Figure 3: 2028 Test Year Forecast Compared to 2023-2027 Annual Average - Distribution OM&A Increase by OM&A Category[5]

As demonstrated in Figure 3, the main categories driving this increase are Sustainment (57%), Common and Other (25%) and Customer Care (11%). Details on the 2028 test year expenditures for Sustainment, Customer Care and Development are provided in this section. Details on Common and Other OM&A, including Digital and Technology Services, security, planning, operations and other corporate support functions, and Property Taxes and Rights Payments can be found in Exhibit E-04-01 and Exhibit E-09-06, respectively.

3.3.1 SUSTAINMENT

The 2028 test year forecast of $523.0M for Distribution Sustainment OM&A reflects an increase of $169.1M (47%) from the 2023-2027 annual average expenditure. This increase is primarily driven by: Vegetation Management ($123.7M), Lines and Other Maintenance ($22.9M), and Meters, Telecom and Control ($12.1M), and Smart Grid

[5] Cost containment is shown as a positive $10.8M variance because there is no cost-containment adjustment included in the 2028 forecast, compared with an annual average reduction of $10.8M over 2023-2027.

($7.1M). These drivers are discussed in the subsections below. For additional details on Sustainment OM&A, refer to Exhibit E-03-02.

3.3.1.1 VEGETATION MANAGEMENT

Hydro One's 104,000 km overhead distribution network traverses heavily forested terrain containing hundreds of millions of trees, and vegetation remains one of the leading causes of distribution outages. Managing vegetation is critical to maintaining system reliability, public safety, and, increasingly, mitigating wildfire risk. To effectively manage these risks, Hydro One must maintain adequate separation between energized conductors and surrounding vegetation.

Hydro One employs a defect-driven approach to vegetation management through its Optimal Cycle Protocol (OCP), which establishes feeder-specific vegetation clearing cycles based on observed defect accumulation and risk. Across the system, the OCP targets an average five-year vegetation management cycle, in accordance with industry benchmarks, to mitigate vegetation-related safety and reliability risks while supporting long-term efficient program delivery. However, as a result of the constraints and the re-pacing of planned work during the current rate period, Hydro One is currently operating at an average cycle length of approximately 8.3 years. To manage the impacts of reprioritization during the 2023-2027 period, Hydro One adjusted its OCP scope, as discussed further in Exhibit E-03-02, and will continue to implement those modifications where they have proven effective. While these measures helped manage short-term risk, scope optimization alone cannot adequately mitigate the long-term risks associated with prolonged vegetation management cycles.

As vegetation continues to grow and work remains deferred, key indicators of system risk and program performance have deteriorated:

- Density defects climbed from 26 defects per kilometre in 2022 to 60 defects per kilometre by year-end 2025.
- Tree-caused SAIDI increased from 2.71 in 2021 to 3.37 in 2025 when tree contacts caused by adverse weather are included (starting in 2024 onward).

- OCP unit costs increased from $4,019 in 2021 to $8,457 in 2025 primarily due to increased defect density.

Without incremental investment, Hydro One expects tree-related reliability performance to continue to deteriorate and vegetation management unit costs to continue rising. As vegetation densities increase, more specialized and higher-cost arborist resources are required, and work crews require more time to complete each unit of work. Continued deferrals would therefore increase both system risk and the cost of future remediation.

Accordingly, Hydro One is proposing $230.9M in 2028 for its Vegetation Management program. This represents an increase of $123.7M relative to the 2023-2027 average annual expenditures. The program is expected to restore at least 76% of Hydro One's distribution rights-of-way to the cyclical 5-year clearing standard by 2032 and reduce the average clearing cycle from 8.3 years to 6.6 years, address all the accumulated brush backlog across the province, and lower line-clearing unit costs by 12% to approximately $7,401 per kilometre. The plan is also expected to help moderate future cost escalation and place the vegetation management program on a more sustainable trajectory.

3.3.1.2 LINES AND OTHER MAINTENANCE

Hydro One's Lines and Other Maintenance program is responsible for identifying, prioritizing, and correcting asset defects that may adversely affect safety, reliability, or system performance. The program supports the ongoing inspection, maintenance, and remediation of distribution system assets and is guided by the investment planning process in DSP Section 3.7. The proposed 2028 forecast will target about 14,100 defect corrections annually based on estimated defect volumes, minimum inspection requirements, and preventive maintenance cycles.

During the 2023-2027 rate period, Hydro One reprioritized portions of its planned maintenance programs to manage increasing demand-driven work volumes, market-based cost pressures and other operating requirements within the available OM&A envelope. While immediate reliability and safety risks continue to be addressed through

inspections, the re-prioritization and deferral of certain planned maintenance activities contributed to a backlog of asset deficiencies and work requirements across the system.

As a result, Hydro One is transitioning from a period of short-term reprioritization to a more sustainable maintenance program. The proposed plan will increase defect correction volumes, support the maintenance of critical equipment that reduces the risk of asset failures and customer outages, and improve asset performance, system reliability, and long-term asset health. Addressing these needs is important to mitigating the risks associated with equipment deterioration and the continued accumulation of maintenance backlogs.

Accordingly, Hydro One is proposing $218.8M in 2028 for its Lines and Other Maintenance program. This represents an increase of $22.9M relative to the 2023-2027 average annual expenditures. The proposed increase supports the following objectives:

- **Corrective Maintenance:** Address a growing backlog of more than 400,000 system deficiencies through a risk-based approach that prioritizes corrective actions for the highest-risk defects based on safety and reliability considerations.
- **Insulator Washing:** Reintroduce insulator washing activities on high-impact feeders to reduce contamination-related flashovers and pole fire risks.
- **Overhead Patrol:** Reflect changes to Hydro One's vegetation management strategy and maintenance cycles by unbundling mandated overhead patrols from the Vegetation Management Program and managing them as a standalone component of the Lines and Other Maintenance program.
- **Underground Cable Diagnostics:** Establish a new program to assess the condition of underground cables and identify deterioration before failure occurs. The resulting condition data will support targeted replacement and rejuvenation activities, reduce the likelihood of customer interruptions and improve long-term asset management outcomes.

Collectively, these expenditures are intended to improve system reliability, strengthen asset condition management, and place the Lines and Other Maintenance program on a more sustainable footing over the 2028-2032 period.

3.3.1.3 METERS, TELECOM AND SMART GRID

Hydro One's Meters, Telecom and Smart Grid programs support the digital and communications infrastructure required to operate an increasingly connected and distributed electricity system. These programs enhance visibility into the distribution network, support data-driven planning and operational decision making, enable the integration of DERs, and support Hydro One's assessment of non-wires solutions as part of the distribution planning in accordance with OEB requirements.

These programs also fund the ongoing operation and sustainment of critical technologies and platforms, including software licensing, platform hosting, telecommunications and cellular services, application support, system maintenance, cybersecurity activities, training, and specialized technical resources. In addition, they support the continued operation of battery energy storage systems (BESS) assets, smart field devices, DER integration capabilities, and the DER Testing Laboratory.

To support these objectives, Hydro One is proposing $46.4M in 2028, consisting of $35.4M for Meters and Telecom and $11.0M for Smart Grid programs. This represents an increase of $19.1M relative to the 2023-2027 annual average expenditures.

The increase is primarily driven by foundational investments that advance grid modernization, including Distribution Intelligence and Distribution Automation (DIDA), Advanced Metering Infrastructure 2.0 (AMI 2.0), Advanced Distribution Management System (ADMS), Distributed Energy Resource Management Systems (DERMS), non-wires solutions, BESS, and other smart grid capabilities. Collectively, these expenditures strengthen Hydro One's ability to manage growing electrification, customer load growth, and increasing DER adoption by improving visibility, enabling advanced monitoring and control capabilities, and supporting flexible, cost-effective grid solutions.

3.3.2 DEVELOPMENT OM&A

Hydro One is proposing $17.6M in 2028 for its Development OM&A program. This represents an increase of $6.6M relative to the 2023-2027 average annual expenditures. This increase is primarily driven by DER Connections and Hosting Capacity Enablement activities required to support incremental DER connection volumes and hosting capacity needs. These activities include engineering studies, coordination, project estimating, and sustainment of power quality monitoring necessary to reliably connect DERs to the distribution system. The proposed forecast also supports anticipated growth in DER connection volumes (see DSP Section 3.4). For additional details on Development OM&A, refer to Exhibit E-03-03.

3.3.3 CUSTOMER CARE

Hydro One is proposing $139.6M in Customer Care OM&A expenditures for 2028, an increase of $31.6M relative to the 2023-2027 average annual expenditures. The increase reflects the need to support evolving customer requirements, growing demand for customer services, and Ontario’s economic growth and electrification objectives. Key expenditures include expanding DER enablement capabilities and maintaining operational capacity as customer interactions continue to increase in both volume and complexity.

The proposed expenditures also support Hydro One's Meter-to-Cash operations, including meter reading, billing, settlements, collections, and field support activities, while leveraging operational improvements from the AMI 2.0 program. In addition, Hydro One is maintaining appropriate provision for Net Bad Debt and strengthening collection capabilities through enhanced customer outreach, payment assistance programs, improved visibility into overdue accounts, and targeted field support activities. Collectively, these expenditures are intended to maintain customer service performance, maintain customer participation in emerging energy programs, and improve operational efficiency over the long term. For additional details on Customer Care OM&A, refer to Exhibit E-03-04.

4.0 REASONABLENESS OF PROPOSED EXPENDITURES

Hydro One's proposed Distribution OM&A expenditures are grounded in an integrated planning process, informed by customer and system needs, and paced to balance operational requirements with customer rate impacts. The plan supports the continued safe and reliable operation of the distribution system while addressing the accumulated impacts of work reprioritization, cost pressures, evolving customer expectations, severe weather, electrification, DER integration, cyber and physical security requirements, and the ongoing transformation of the electricity sector over the forecast period.

The 2028 OM&A proposal is not simply an increase over the current rate term. It reflects the funding required to establish a sustainable operating baseline for the next rate period. Hydro One's 2023 to 2027 experience demonstrates that the Company made difficult operating decisions to manage within the overall rate period envelope. For the next rate period, the proposed funding supports restoring deferred work where needed, supporting a larger capital program, maintaining reliable and resilient service, and building the capabilities required for Ontario's electricity transition.

Hydro One's 2028 Distribution OM&A plan of $958.7M was developed through a bottom-up planning process grounded in asset condition data, operational requirements, and the maintenance and operational activities necessary to support and execute Hydro One's Distribution System Plan (DSP). The OM&A forecast reflects customer needs and preferences, promotes the OEB's Renewed Regulatory Framework (RRF) outcomes, and is supported by Hydro One's demonstrated capability to effectively prioritize and deliver OM&A programs. The planning context, customer engagement, alignment with RRF outcomes, and Hydro One's ability to execute the plan are described in the subsections below.

Hydro One also monitors performance and cost efficiency through operational and financial metrics that assess program delivery and cost control over time. The Hydro One Distribution OEB Scorecard tracks OM&A efficiency, work accomplishment, and cost control metrics, including vegetation management gross defect correction cost per

kilometre, OM&A dollars per customer, OM&A dollars per kilometre of line, and kilometres of forestry managed. Historical performance and forecast targets are provided in DSP Section 3.5. In addition, an external benchmarking analysis of Common Corporate Costs assessed the efficiency and effectiveness of Hydro One's centralized corporate functions. Further details are provided in Exhibit E-04-02, with the study included as Attachment 1.

4.1 PLANNING CONTEXT

As described in SPF Section 1.7, Hydro One's 2028 Distribution OM&A forecast was developed on a bottom-up basis, informed by the actual condition of distribution assets and customer needs. Consistent with Hydro One's lifecycle approach to system planning and asset management, planning teams developed the OM&A plan in coordination with the capital investments set out in the Distribution System Plan (DSP Section 3.1), through a risk assessment of candidate maintenance and operational activities based on safety, reliability, and environmental risk, considering customer input, management insight, and the Company's strategic priorities. Capital investments in asset renewal, system access, system service, grid modernization, DER enablement, and system resiliency create new and refurbished assets that require ongoing maintenance, operational support, inspection, outage coordination, customer support, technology enablement, and work execution capability. The OM&A plan provides the maintenance, inspection, vegetation management, customer care, distribution development, planning, system operations, and security activities necessary to preserve asset health, extend useful life, support capital delivery, and help customers realize the benefits of the investment plan.

4.2 CUSTOMER ENGAGEMENT

As detailed in SPF Sections 1.6 and 1.7, feedback from customer engagement directly informed and shaped the development of the investment plan. In 2024 and 2025, Hydro One retained Innovative Research Group (IRG) to conduct Hydro One's multi-phase customer engagement process that informed and refined the investment plans in this Application, including both the capital and OM&A plans (the IRG Study). The customer priorities identified through this process, including system reliability, asset stewardship,

and service quality, are delivered in part through OM&A-funded maintenance, inspection, and operational activities.

The IRG Study results indicate strong support for Hydro One's draft investment plans, including the operational expenditures necessary to maintain system reliability and asset condition. As stated in the IRG Overview Report (see SPF Section 1.6, Attachment 1): "Overall, feedback collected from more than 100,000 customers shows that there is strong support across all customer types for a level of investment at or above Hydro One's 2028-2032 draft plans."

Key customer feedback from Phase II, in respect of distribution, included the following:

- Across all customer types, a majority of customers support Hydro One spending at or above the level in the draft plan as it relates to distribution investments in overall system reliability, managing severe weather, and targeted reliability improvements. The proposed OM&A expenditures deliver on these preferences by funding maintenance and operational activities that sustain day-to-day reliability, maintain asset condition, reduce outage risk, and improve service restoration.
- Customers expressed strong support for investments that improve the day-to-day reliability of the distribution system, including repairing or replacing overhead line defects, maintaining and repairing station equipment, and addressing underground cables. The proposed OM&A plan contributes to these outcomes through maintenance and repair programs that identify and address equipment defects, maintain the health of distribution stations, and support the continued reliable operation of distribution assets. These activities help reduce the risk of equipment failures, outages, and costly emergency repairs over time.
- Customers also expressed strong support for investments that improve the distribution system's resilience to severe weather. The draft plan included reinforcing vulnerable power lines, increasing vegetation management activities, and deploying automated intelligent switches to reduce outage impacts and improve restoration times. The Distribution OM&A plan delivers these outcomes through line maintenance and repair activities, vegetation management programs

that reduce tree-related outages, and operational support for grid automation technologies.

As detailed in SPF Section 1.7, Hydro One refined its distribution investment plans based on the results of its customer engagement. This refinement also considered other factors, including the alignment between asset needs and overall costs, resulting in plans that reflect customer needs and preferences alongside other planning considerations. The OM&A plan is calibrated to deliver the maintenance and operational activities required to advance the reliability, resiliency, and stewardship outcomes that customers prioritize.

4.3 ALIGNMENT WITH RRF OUTCOMES

The proposed Distribution OM&A plan is designed to advance the OEB's RRF outcomes:

- **Customer Focus:** The OM&A plan supports reliable electricity delivery through preventive maintenance, inspections, and vegetation management. It also enables timely and accurate customer service through Customer Care activities, including service delivery across digital and traditional channels, billing and collections, and analytics supporting customer experience enhancements. The plan further supports evolving customer needs by enabling participation in emerging energy programs and access to financial assistance to address affordability.
- **Operational Effectiveness:** The OM&A plan supports top-tier safety performance by funding safety-critical maintenance activities, mandatory compliance programs, and improving long-term reliability by restoring deferred preventive maintenance cycles, addressing accumulated work backlogs, and ensuring that the condition data generated through ongoing maintenance informs capital replacement prioritization.
- **Public Policy Responsiveness:** The OM&A plan reflects mandated service obligations under the Distribution System Code, the *Ontario Energy Board Act, 1998,* and other applicable legislation, such as the *Getting Ontario Connected Act, 2022.* It also supports compliance with ongoing metering, environmental and customer service quality requirements.

- **Financial Performance:** The OM&A plan achieves reasonable and stable rate impacts by pacing and prioritizing work over the forecast period, while continuing to address the highest-priority safety, reliability, compliance and customer needs. Affordability considerations helped shape the plan, including decisions on timing and sequencing of work, so that proposed expenditures reflect a balanced approach to system needs, customer outcomes, execution feasibility, and rate impacts. Within the Sustainment program, for example, Hydro One has paced its Vegetation Management investment to bring at least 76% of ROW back to standards by the end of 2032, with the objective of returning to an average 5-year return-to-site cycle in the 2033-2037 rate period.

4.4 ABILITY TO EXECUTE PLAN

Hydro One has demonstrated its ability to effectively manage Distribution OM&A expenditures throughout the 2023 to 2027 rate period. As discussed in Section 3.0 of this Exhibit, Hydro One substantially aligned its Distribution OM&A expenditures to total funding levels established in the rebasing application, while making prudent prioritization decisions to address emerging mandatory and demand-driven requirements within available funding. The development of the proposed 2028 to 2032 OM&A plan is informed by experience gained during the current rate period, including historical unit costs, work volumes, productivity expectations, and lessons learned from program execution.

The work execution strategy detailed in Exhibit E-03-05 demonstrates that Hydro One has the capability, processes, and governance to deliver the proposed 2028 to 2032 investment plan. Hydro One's demonstrated ability to manage OM&A expenditures prudently during the current rate period, while reprioritizing work to address system needs within available funding, supports the feasibility of the proposed OM&A plan. The proposed funding supports a transition from short-term deferral and reprioritization measures to a more sustainable operating model that supports the continued delivery of safe, reliable, resilient, and secure service for customers.

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CHAPTER 2 APPENDIX 2-JA, 2-JB, 2-JC AND 2-L – DISTRIBUTION OM&A EXPENDITURES

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DISTRIBUTION SUSTAINMENT OM&A

1.0 INTRODUCTION

Distribution Sustainment OM&A consists of expenditures required to maintain existing distribution system assets and facilities so that they continue to operate safely, reliably, and as originally designed. These expenditures enable Hydro One to deliver reliable service to approximately 1.5 million customers, maintain compliance with legislative, regulatory, environmental, and safety requirements, and support the long-term health of the distribution system.

Hydro One's Distribution Sustainment OM&A program is organized into five categories:

- **Stations**: Maintenance, inspection, testing, and repair of distribution station assets and supporting infrastructure.
- **Lines**: Inspection, maintenance, repair, and restoration activities associated with overhead and underground distribution assets.
- **Meters, Telecommunications, and Control**: Activities required to maintain metering accuracy, communications infrastructure, control systems, and grid visibility.
- **Vegetation Management**: Vegetation clearing, brush control, and rights-of-way maintenance required to support safety and reliability.
- **Smart Grid**: Activities that sustain and expand grid modernization capabilities, including distributed intelligence, advanced communications, distributed energy resources, and Non-Wires Solutions.

Distribution Sustainment OM&A includes both planned work and demand-driven work. Planned work consists of inspections, condition assessments, preventive maintenance, and other activities completed on established cycles to preserve asset condition and identify emerging risks before they result in service disruptions. Demand-driven work addresses customer requests, public safety concerns, trouble calls, equipment failures, outage restoration, and other operational requirements that cannot be scheduled in advance.

Hydro One manages these expenditures using condition-based and time-based maintenance strategies that prioritize work according to risk, asset condition, customer impacts, and regulatory obligations. This approach supports prudent asset stewardship while balancing reliability, safety, and affordability.

Sustainment OM&A work is informed in part by the asset-condition, demographic and performance information described in DSP Section 3.2, which identifies populations of poor-condition station and line assets, accumulated inspection defects, aging underground cable with deteriorating performance, and deteriorated distribution rights-of-way. Depending on the nature and consequence of the deficiency, an asset may require additional monitoring, preventive or corrective maintenance, refurbishment, or capital replacement. Hydro One's proposed OM&A expenditures support the inspection, diagnostic, preventive, corrective and vegetation-management activities required to manage deficiencies, maintain assets, identify emerging risks and support the prioritization of capital intervention where replacement is warranted.

1.1 PROGRAM EXPENDITURE OVERVIEW

Table 1 below sets out Hydro One's planned expenditures for the 2028 Test year, along with the forecast and actual spending level for the Bridge and Historical years, for each of the Distribution Sustainment OM&A categories.

Table 1 - Summary of Sustainment OM&A ($M) - Hydro One[1]

Sustainment OM&A	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Stations	23.4	25.5	23.3	22.3	22.7	26.8
Lines	204.0	202.6	179.8	196.8	196.5	218.8
Meters, Telecom & Control	20.6	20.1	20.8	29.7	25.5	35.4
Vegetation Management	117.9	116.8	92.6	103.2	105.4	230.9
Smart Grid	0.3	1.0	2.8	7.5	8.2	11.0
Total Sustainment OM&A	**366.2**	**365.9**	**319.3**	**359.4**	**358.2**	**523.0**

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

The 2028 Test year expenditure for Sustainment OM&A is $523.0M, a $156.8M increase over 2023 actuals, and a $169.2M increase over the average of the last rate period (2023-2027).

Between 2023-2025, Hydro One faced increasing demand-driven work requests, compliance work requirements and inflationary pressures. To manage these pressures within a 5-year funding envelope, Hydro One reprioritized funding across programs and years. This included scaling back on planned Vegetation Management and Lines Maintenance programs that could be deferred without introducing an unacceptable level of risk to the system for the remainder of the rate period.

While these prioritization decisions were necessary to address urgent operational and compliance requirements in the short term, continued deferrals are not sustainable over the long term. The distribution system is showing signs consistent with the cumulative effects of maintenance deferrals. As discussed in DSP Section 3.5, equipment failure accounts for approximately one-third of customer outage hours, tree contacts increased through 2023–2025, and poor-condition assets and deteriorating rights-of-way will create a lag before resumed renewal and maintenance programs improve SAIDI and SAIFI. These trends highlight the need to restore planned maintenance and vegetation management activities, address accumulated defects and backlogs, and reduce reliance on reactive trouble-call and run-to-failure work. Continued deferrals in planned maintenance increase the risk of asset deterioration, reduce the effectiveness of preventive maintenance programs, and elevate the likelihood of service interruptions, public safety incidents, and higher future remediation costs.

The 2028 Test year forecast enables Hydro One to restore planned maintenance and vegetation management activities to the levels required to appropriately manage the distribution system, resume previously deferred activities, and address accumulated maintenance backlogs across key distribution asset classes. These investments are necessary to preserve asset condition, maintain compliance with inspection and

maintenance requirements, support long-term reliability, and mitigate future operational risks.

The proposed 2028 Test year expenditure of $523.0M is primarily driven by the resumption of deferred maintenance and vegetation management work, sustained demand-driven maintenance requirements, and investments necessary to support Advanced Metering Infrastructure (AMI 2.0), Distributed Intelligence and Distribution Automation (DIDA), Battery Energy Storage Systems (BESS), and Non-Wires Solutions.

1.2 TOP DRIVERS OF 2028 SUSTAINMENT OM&A

The principal drivers of the 2028 Test year forecast are Vegetation Management, Lines Sustainment, and Meters, Telecommunications, and Control.

Vegetation Management: The plan increase reflects a planned expansion of core sustainment activities, including an increased rate of line clearing to maintain required vegetation clearances, and resuming the brush control program to manage vegetation growth along the corridor floor. Hydro One's forecast expenditure plan for 2028-2032 is expected to bring at least 76% of Distribution Rights of Way back to the cyclical clearing standard by the end of the rate period. Changes to Hydro One's vegetation management program are intended to proactively manage asset condition and vegetation-related risks, thereby supporting system reliability, reducing the likelihood of outages, and reducing reliance on demand programs.

Lines Sustainment: The plan increase reflects expenditures to resume deferred activities, address identified defects, and maintain compliance with inspection requirements. The plan includes the unbundling of overhead patrols from the Vegetation Management program to be managed independently under lines sustainment, continued line maintenance and trouble call activities, implementation of an underground cable diagnostic program and resuming the insulator washing program. These investments support the early identification and correction of emerging asset condition risks, reduce reliance on run-to-failure strategies, improve service reliability, and help maintain service

levels consistent with customer expectations and to comply with the service quality requirements set out in Section 7 of the Distribution System Code.

Meters, Telecommunications, and Control: This investment is primarily associated with the transition to AMI 2.0, a multi-year initiative to replace the AMI 1.0 legacy system with current-generation smart meters and communications network equipment across the service territory. This includes maintaining serviceable battery backup capability on network equipment, better analytics enabled by more granular AMI 2.0 data, which improves network visibility and billing accuracy, and increased meter volumes, which result in incremental Software-as-a-Service (SaaS) costs. The AMI 2.0 program is currently in progress and is scheduled for completion in 2029 as discussed in DSP Section 3.11, D-SR-12. These investments support system reliability, data integrity, and accurate customer billing.

2.0 SUSTAINMENT OM&A PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

Section 2.0 includes detailed program and sub-program descriptions and variance explanations for each of the Sustainment OM&A programs: (i) Stations, (ii) Lines, (iii) Meters, Telecoms and Control, (iv) Vegetation Management, and (v) Smart Grid.

2.1 STATIONS

The stations program is essential to maintaining the ongoing performance, reliability and safety of the distribution system. Hydro One owns, operates, and maintains 1009 distribution and regulating stations, as well as a fleet of 33 mobile unit substations (MUS). Distribution stations step down voltage from transmission or sub-transmission levels to primary distribution voltage for distribution customers. Regulating stations are a special type of station that maintains voltage within prescribed limits in response to load variations that can cause voltage increases or decreases.

Distribution stations can include the following components:

- station transformers and regulators;
- station reclosers and breakers;

- station switches and fuses;
- station structures;
- station fences;
- station grounding systems;
- station service transformers;
- station insulators;
- station protection relays;
- bus;
- station Intelligent Electronic Devices (IED); and,
- station spill containment systems.

MUSs support emergency power restoration in the event of a transformer or other station component failure, carry load to enable maintenance and capital work to proceed, and provide load relief as required. Hydro One will expand its MUS fleet to 34 units by acquiring an additional unit by 2028.

Stations sustainment expenditures are divided into three programs, summarized below and discussed in more detail in the sections that follow:

- **Station Inspections and Planned Preventive Maintenance (section 2.1.1):** This program funds the inspection of station equipment which involves monitoring condition, identifying deficiencies and performing testing on de-energized equipment before it is returned to service.
- **Stations Demand and Planned Corrective Maintenance (section 2.1.2)**: This program funds the response to emergency failures and addresses equipment deficiencies at distribution and regulating stations.
- **Land Assessment and Remediation (section 2.1.3)**: This program funds the testing and remedial work required to manage contaminated soil at distribution and regulating stations.

Table 2 sets out planned expenditures for the 2028 Test year, along with the forecast and actual spending levels for the Bridge Year (2027) and Historical Period (2023-2026), for each of the three Sustainment OM&A categories.

Table 2 - Distribution Sustainment Stations OM&A ($M)

Sustainment Stations OM&A	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Inspections and Preventive Maintenance	9.9	10.1	9.4	9.5	9.7	9.8
Demand and Corrective Maintenance	13.2	14.6	13.4	12.3	12.5	16.7
Land Assessment and Remediation	0.3	0.8	0.4	0.5	0.5	0.3
Total	**23.4**	**25.5**	**23.3**	**22.3**	**22.7**	**26.8**

The 2028 Test year expenditure for Distribution Stations OM&A is $26.8M, a $3.4M increase over 2023 actuals, and a $3.4M increase over the average of the last rate period (2023-2027).

The increase in the 2028 Test year is primarily due to higher volumes of transformer preventive and corrective maintenance, and maintenance of associated switches and fuses that provide isolation and protection for these transformers, as discussed further in Sections 2.1.1 and 2.1.2.

2.1.1 STATION INSPECTIONS AND PLANNED PREVENTIVE MAINTENANCE

2.1.1.1 PROGRAM DESCRIPTION

The station inspections and planned preventive maintenance program addresses the inspection, testing and preventive maintenance of station equipment in line with regulatory requirements and industry-best practices. Figure 1 below provides a breakdown of the 2028 work program expenditures allocated across stations inspections and planned preventive maintenance (including testing).

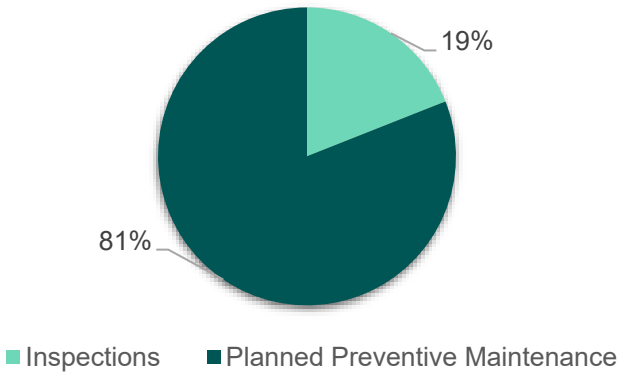

Figure 1: Breakdown of 2028 Stations Inspections and Planned Preventive Maintenance Expenditures

Station Inspections

There are two types of stations inspections – visual inspections of station assets and thermography inspections of all station power equipment. Visual inspections of station assets are conducted periodically to identify reliability issues, environmental issues, structural problems, safety hazards, equipment defects and signs of vandalism, as required by the Distribution System Code Appendix C. Hydro One's rural stations are inspected twice per year, and urban stations are inspected monthly. Thermography inspections are completed of all station power equipment to identify hot spots in any of the electrical equipment and components. Hydro One's distribution station electrical equipment is inspected using thermography every two years.

In 2028, Hydro One plans to conduct approximately 6,700 inspections. This is aligned with the volume of inspections conducted over the 2023-2025 historical and 2026-2027 forecast years.

Planned Preventive Maintenance

Planned maintenance of station power equipment is undertaken to mitigate the risk of failures and support the safe and reliable operation of the distribution system. This maintenance reduces the likelihood of equipment failure and helps maintain customer reliability and system performance. The planned preventive maintenance program

addresses transformers, reclosers, breakers, switches & fuses, mobile unit substations, and other stations assets. Figure 2 below provides a breakdown of the 2028 work program expenditures allocated across these asset types, and the sections that follow provide further details of the preventive maintenance activities performed for each asset.

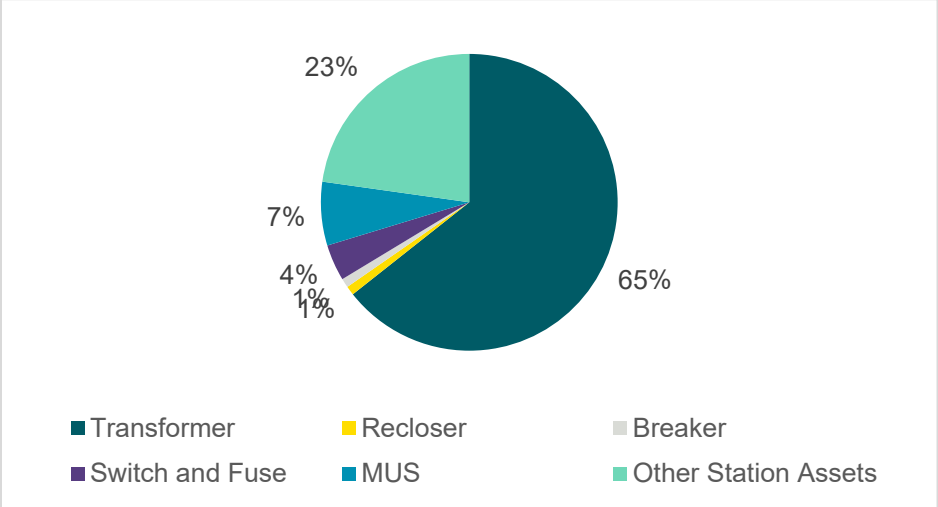

Figure 2: Breakdown of 2028 Stations Planned Preventive Maintenance Expenditures

Transformer Preventive Maintenance

In addition to visual and thermography inspections outlined above, station transformers receive the following maintenance activities:

- **General Oil Test**: Annually, an oil sample is taken from the transformer main tank and sent to a third-party lab to obtain industry-standard diagnostic test results including dissolved gas analysis (DGA), Moisture Content and Furan Analysis. If the oil sample result is unsatisfactory, further diagnostic testing and internal inspection is undertaken.
- **Transformer Diagnostic Test**: Upon receipt of an unsatisfactory oil sample result, the main tank of the transformer may be subject to diagnostic testing and an internal inspection. This maintenance activity includes the following: inspection of current carrying parts, bushing oil level check, insulation resistance tests, turns ratio and phase angle tests, core loss test, dissipation factor and capacitance test,

winding resistance test, inspection of oil conservator breather, repair of minor or moderate oil leaks, function test of pressure vacuum device, check and top-up oil levels, function test of gauges and indicators, and application of touch-up painting to mitigate rust.

- **Under-Load Tap-Changer Oil Analysis**: Annually, an oil sample is taken from oil-filled tap-changer compartments and sent to a third-party lab for analysis to obtain industry-standard diagnostic test results including DGA and Moisture Content.
- **Tap-Changer Selective Intrusive Inspection**: Upon receipt of an unsatisfactory oil sample result, or in the event of unsatisfactory performance, internal inspection and maintenance of under-load tap-changers with mechanical moving parts is performed. This maintenance activity includes the following: filtration of insulating oil, flush and clean oil compartments, visual check for oil leaks and contact wear, inspection of current carrying parts, checks of insulation condition, collector ring, drive chains, pushrod, reversing switch, oil compartment door gaskets, exercise isolation and grounding switch, function test of operating limit switches, gauges and indicators.
- **Power Factor Test (applicable to HVDS transformers only)**: Distribution station transformers with primary voltages of 115kV and 230kV are subject to a power factor test to verify the integrity of the transformer insulation material and to ensure they are functioning correctly. This test is performed when the transformers are removed from service for *diagnostic* testing or *selective intrusive* maintenance.

The volume of transformer maintenance activities is driven by both the number of transformers in service and the condition of the transformer population. Certain activities, such as annual oil sampling are performed on all transformers and therefore scale directly with the number of units in service. Other activities, including condition-based inspections, diagnostic testing, and internal inspections, are driven by asset condition. For example, where oil sample results are unsatisfactory or visual inspections identify issues such as oil leaks, additional testing and inspections are undertaken as required and are typically coordinated with corrective maintenance activities.

In 2028, transformer diagnostic testing and intrusive inspections are forecasted to increase from a historical average of 61 transformers per year to 80 transformers. This transformer diagnostic testing and intrusive inspections are bundled with transformer planned corrective maintenance work. From 2023-2025, Hydro One planned approximately 80 and completed an average of 61 transformer corrective maintenance jobs per year. This discrepancy between planned and completed corrective maintenance jobs was due to limited MUS availability and the prioritization of demand work. The 2028 Test year funding will provide for 80 planned transformer corrective maintenance jobs to address leaks and internal defects identified from annual oil sampling that can lead to failure if not addressed, consistent with the number of planned jobs in 2023-2025.

Transformer preventive maintenance accounts for approximately 65% of the total expenditure under the Planned Preventive Maintenance Program in the 2028 Test year. The 2028 work program includes approximately 2,700 transformer oil samples, diagnostic tests, intrusive inspections, and power factor tests. These forecasted work volumes are generally consistent with 2023–2025 historical actuals and 2026–2027 forecast levels, with a modest increase reflecting the higher volume of transformer diagnostic testing and intrusive inspections planned for 2028.

Recloser Preventive Maintenance

Recloser manufacturers recommend maintenance based on the number of operations performed. The rate of contact deterioration depends on both the number of operations and the type of interrupter technology used (e.g., oil or vacuum).

Hydro One performs recloser maintenance based on operation counts and defects identified during station visual inspections and thermography inspections. Preventive maintenance activities are coordinated with station inspection programs. During station inspections, station electrical maintenance staff visually inspect reclosers for signs of deterioration or other defects. Operation counters are also reviewed and recorded to ensure the equipment has not exceeded the manufacturer's recommended maintenance interval. Because recloser preventive maintenance is typically bundled with scheduled,

time-based station inspections, the level of recloser preventive maintenance is generally correlated with the number of reclosers in service.

Reclosers are also subject to infrared thermography inspections every two years. These inspections identify overheating components, which may indicate deteriorating equipment and an increased likelihood of failure.

Recloser preventive maintenance accounts for less than 1% of the total expenditures under the Planned Preventive Maintenance Program in the 2028 Test year. The 2028 work program is consistent with Hydro One's established recloser maintenance strategy and reflects work volumes that are consistent with 2023–2025 historical actuals and 2026–2027 forecast levels. Recloser preventive maintenance work volumes are minimal. They are inspected during station visual inspection activities, at which time defects and counter operations are recorded. Reclosers with defects or exceeded counter operations are addressed under Recloser Corrective Maintenance.

Breaker Preventive Maintenance

The station breaker population consists primarily of metal-clad breakers that must be removed from service to assess their internal condition. As a result, a condition-based maintenance strategy is generally not practical, and Hydro One instead follows a time-based maintenance approach. Station breakers are removed from service every six years for inspection and maintenance. During these outages, breakers undergo:

- **Diagnostic Testing**: Functional testing, manual operation checks, and cleaning and lubrication of operating mechanisms.
- **Selective Intrusive Inspection**: Inspection of internal components, insulation condition, contacts, and rack-in mechanisms, where applicable.

This maintenance strategy helps identify degradation that cannot be detected while the breaker remains in service and supports the continued reliable operation of station equipment.

Breaker preventive maintenance accounts for approximately 1% of the total expenditures under the Planned Preventive Maintenance Program in the 2028 Test year. The 2028 work program includes preventive maintenance on approximately 23 station breakers. This represents approximately 12% of the station breaker population. While a six-year maintenance cycle would generally require a slightly higher annual maintenance volume, outage constraints limit the number of breakers that can be taken out of service each year.

Switch & Fuse Preventive Maintenance

Station switches and fuses are visually inspected during routine station inspections.

Station switches are test operated when they are removed from service to support transformer maintenance work or when other outage opportunities arise. Switches that fail to operate are addressed under the corrective maintenance program, where feasible.

Preventive maintenance of fuses is coordinated with transformer maintenance activities and other planned outages to minimize service interruptions and maintenance costs. When transformers are removed from service for maintenance, associated fuses are inspected and tested. Fuses that do not meet performance requirements are replaced through the corrective maintenance program.

Preventive maintenance of switches and fuses accounts for approximately 4% of the total expenditures under the Planned Preventive Maintenance Program in the 2028 Test year. The 2028 work program includes testing of approximately 90 station switches and 80 fuses. These forecasted work volumes are generally consistent with 2023–2025 historical actuals and 2026–2027 forecast levels, with a modest increase reflecting the higher volume of transformer diagnostic testing and selective intrusive inspections planned for 2028.

Mobile Unit Substation (MUS) Preventative Maintenance

MUS Units are critical distribution system assets that support emergency restoration during unplanned outages and provide temporary supply during planned capital projects and maintenance activities. All MUS trailers undergo an annual inspection as required by

the Ontario Ministry of Transportation (MTO) and must maintain a valid MTO inspection certificate. These inspections help ensure the trailers remain safe and roadworthy for deployment when required.

In addition to mandated transportation inspections, Hydro One inspects and performs comprehensive maintenance on the power equipment within each MUS every two years. The maintenance activities performed on MUS transformers, switches, fuses, reclosers, and other electrical components are consistent with those performed on comparable equipment installed in stations.

MUS preventive maintenance accounts for approximately 7% of the total expenditure under the Planned Preventive Maintenance Program in the 2028 Test year. The 2028 work program includes inspection of the entire MUS fleet and preventive maintenance of approximately one-half of the MUS power equipment fleet. These forecasted work volumes are consistent with Hydro One's established maintenance cycle for MUS equipment.

Other Station Assets Preventive Maintenance

In addition to the assets discussed above, Hydro One's distribution stations include structures, fences and gates, access roads, foundations, drainage systems, grounding systems, station service transformers, insulators, and buses. Stations equipped with breakers or vacuum electronic reclosers also include protection relays or intelligent electronic devices (IEDs). These assets are generally inspected for defects during routine station visual inspections. Live electrical components are also included in station thermography inspections to identify overheating equipment or other emerging issues requiring corrective action.

Stations identified as having elevated environmental risk may also be equipped with spill containment systems that can require six months or monthly inspections. The 2028 work program includes the completion of approximately 550 such inspections.

Stations equipped with breakers have backup 48V or 120V batteries and chargers that must be regularly tested and inspected to allow the breakers to operate. The 2028 work program includes the completion of approximately 290 battery and charger tests and inspections.

Vegetation management is performed within station yards and along access roads to maintain safe operating conditions and mitigate step-and-touch potential hazards. Weed control is typically undertaken two to three times per year, and grass cutting at stations in urban areas is typically performed twice per month from May through October.

Other station asset preventive maintenance accounts for approximately 23% of the total expenditure under the Planned Preventive Maintenance Program in the 2028 Test year. The provided work volumes for spill containment inspections, battery and charger tests, herbicide applications and grass cuts are consistent with 2023–2025 historical actuals and 2026–2027 forecast levels.

2.1.1.2 PROGRAM EXPENDITURES

Table 3 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Stations Inspections and Planned Preventive Maintenance OM&A.

Table 3 - Stations Inspections and Planned Preventive Maintenance OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Stations Inspections and Planned Preventive Maintenance	9.9	10.1	9.4	9.5	9.7	9.8

The 2028 Test year expenditure for Stations Inspections and Planned Preventative Maintenance is $9.8M, a $0.1M decrease from 2023 actuals, and a $0.1M increase over the average of the last rate period (2023-2027).

The preventive maintenance volumes are largely consistent with historical actuals and bridge-year forecasts. The increase in expenditure is primarily attributable to a modest increase in equipment testing performed in conjunction with transformer condition-based maintenance. As discussed above, some condition-based maintenance activities identified between 2023 and 2025 were deferred due to limited Mobile Unit Substation (MUS) availability. Beginning in 2027, Hydro One will expand its MUS fleet through the Mobile Unit Substation Program discussed in DSP Section 3.11, D-SR-02, enabling additional transformer condition-based maintenance work to be completed in 2028.

Although the volume of equipment testing associated with transformer condition-based maintenance is expected to increase, the overall impact on expenditures is limited because Hydro One's station preventive maintenance program is driven primarily by time-based activities, including station inspections and transformer oil sampling.

The 2028 forecast reflects planned station inspections, transformer oil sampling, and equipment testing performed in conjunction with transformer maintenance activities. Bundling these activities minimizes planned outages and enables more efficient deployment of MUS resources.

2.1.2 STATIONS DEMAND AND PLANNED CORRECTIVE MAINTENANCE

2.1.2.1 PROGRAM DESCRIPTION

Station transformers supply an average of 1,536 customers, with interruptions at some of Hydro One's larger and more critical stations affecting more than 3,000 customers. The Stations Demand and Planned Corrective Maintenance Program enables Hydro One to respond to station equipment failures and identified deficiencies to maintain safe and reliable service in accordance with good utility practice. This program consists of:

- (i) demand corrective maintenance to address emergent repairs required in response to equipment failures identified through trouble calls, outages, or station inspections where the condition of the equipment presents an imminent reliability or safety risk; and

- (ii) planned corrective maintenance to address deficiencies identified through station inspections and preventive maintenance activities that need to be addressed but do not present an imminent reliability or safety risk.

When this work involves the repair of a component, it is funded by these corrective OM&A programs. If the resolution involves a capital expenditure such as the replacement of damaged or defective equipment, this replacement is funded by the Distribution Station Demand Capital Program as outlined in DSP Section 3.11, D-SR-01.

Figure 3 below provides a breakdown of the 2028 work program expenditures allocated across demand and planned corrective maintenance activities for the various station asset types. The sections that follow provide further details regarding the corrective maintenance activities performed in this program.

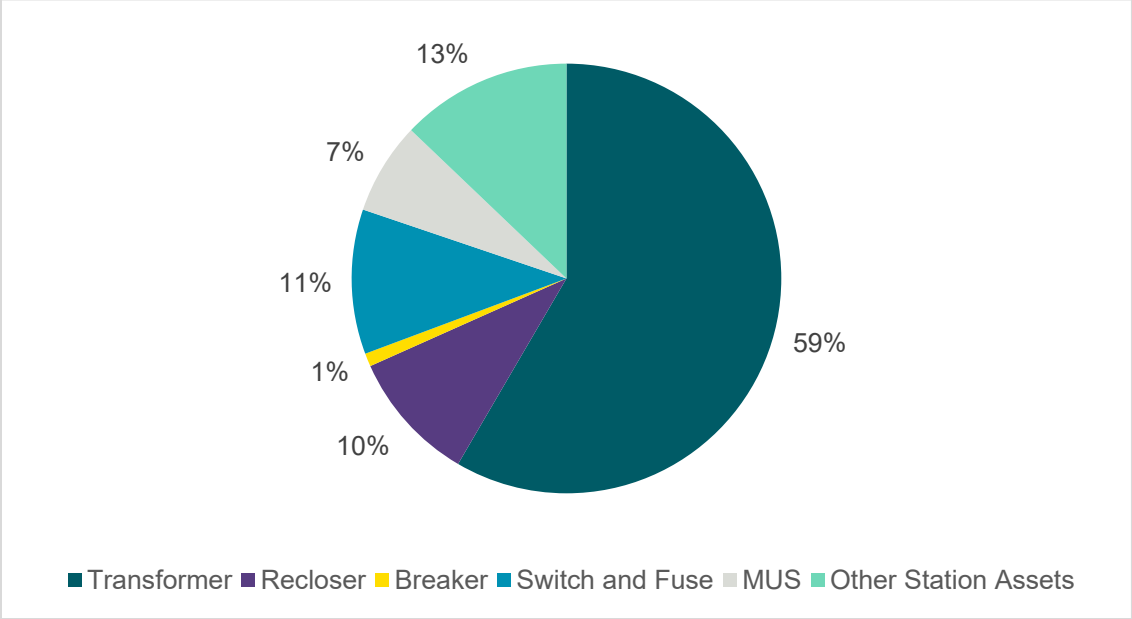

Figure 3: Breakdown of 2028 Stations Demand and Planned Corrective Maintenance Expenditures

The work in this program supports system reliability and safety by:

- Responding to failures of station equipment, such as transformers, regulators, reclosers, switches, and fuses, to facilitate timely restoration of power;
- Preventing service interruptions by addressing equipment with an elevated risk of failure before an outage occurs;
- Correcting conditions that present a safety hazard to the public or Hydro One personnel;
- Addressing deficiencies identified through station inspections and preventive maintenance activities, including adverse dissolved gas analysis (DGA) results, equipment oil leaks, overheating identified through thermography inspections, and damaged insulators;
- Repairing station site deficiencies, such as damaged fences and gates, deteriorated breaker buildings, and access road conditions that could affect the safe and reliable operation of the station; and
- Maintaining Mobile Unit Substations (MUSs) in a state of operational readiness so they can be deployed when required to support timely restoration of service following equipment failures or planned outages.

Transformer Corrective Maintenance

Transformer demand corrective maintenance involves responding to station power transformer outages caused by failures of transformer windings, bushings, or potential transformers. It also includes responding to customer voltage complaints that may arise from failures of under-load tap changers, which are transformer components used to automatically regulate voltage. Demand corrective maintenance activities typically involve deploying station maintenance staff to investigate and, where possible, repair the failed equipment. Where repairs are extensive, a Mobile Unit Substation (MUS) may be deployed to restore service, or load may be transferred to another station where operationally feasible.

Planned corrective maintenance for station power transformers addresses deficiencies identified through routine station visual inspections and annual transformer oil sampling,

as described in the Station Inspections and Planned Preventive Maintenance sections above. The majority of this work relates to:

- Condition-based maintenance (CBM) triggered by high-risk oil sample results from transformer main tanks or tap changers. Oil sample results may identify:
    - Elevated dissolved gas analysis (DGA) results, which can indicate partial discharge, winding deterioration, or overheating of internal insulation; and
    - Elevated moisture levels, which may indicate water ingress into the transformer.
- Corrective maintenance of oil leaks, including repairs to transformer components to prevent oil loss and further equipment deterioration.

Transformers less than 20 years of age require minimal planned corrective maintenance. In recent years, very few have needed to be removed from service to address deficiencies. The condition of these younger transformers is monitored through station inspections and oil samples.

Transformer candidates for high DGA and high moisture corrective maintenance are generally more than 20 years of age. Transformer candidates for leak repairs are generally more than 30 years of age.

As a result of the prioritization of candidate capital projects (see DSP Section 3.7), not all transformers with high DGA / moisture content or oil leak defects will be replaced during the 2028-2032 forecast period. As described in DSP Section 3.2 subsection 3.2.2.1, approximately 19%, or 231 Hydro One Rate Zone station transformers are in poor condition, with 86 planned replacements proposed through D-SR-04 and 20 planned replacements proposed in D-SS-01. In addition, absent replacement, the proportion at or beyond the 50-year expected service life would rise from 45% in 2025 to 55% by 2032. The planned transformer inspection, diagnostic and corrective maintenance activities respond in part to this condition profile. While some select, higher risk transformers have been identified for replacement, other poor condition or older transformers will remain in

service and require condition monitoring and corrective maintenance to manage failure risk.

Transformer corrective maintenance accounts for approximately 59% of the total expenditure under the Stations Demand and Planned Corrective Maintenance Program. Hydro One plans to complete approximately 80 planned transformer corrective maintenance jobs in 2028. Each job requires the transformer to be removed from service for internal inspection and repair.

Between 2023 and 2025, Hydro One completed an average of approximately 61 planned transformer corrective maintenance jobs annually. Historical completion volumes were approximately 25% below planned levels due to limited availability of Mobile Unit Substations (MUSs), which are required to facilitate transformer outages while maintaining customer service. Beginning in 2027, Hydro One will expand its MUS fleet through the Mobile Unit Substation Program as discussed in DSP Section 3.11, D-SR-02, enabling a higher volume of planned transformer corrective maintenance work to be completed in 2028. Hydro One needs to increase the number of annual transformer corrective maintenance jobs from 61 to 80 annually because these transformers are in poor condition based on oil leaks and internal defects, and these defects can lead to failure if not addressed.

Recloser Corrective Maintenance

Recloser demand corrective maintenance involves responding to feeder outages caused by failure of station reclosers when required to open and reclose to clear system faults, or responding to feeder outages caused by station reclosers which operated as required but were unable to clear the fault. Demand corrective activities can involve either replacement of the recloser if failed, or resetting the recloser as needed.

Recloser planned corrective maintenance is performed on reclosers primarily when counter readings have exceeded the manufacturer recommended number of operations. Oil hydraulic reclosers including Cooper model Type “D”, “DV” and “W” are physically

removed from the station and sent to a maintenance shop for overhaul where the recloser contacts, oil and other components are replaced based on their condition.

For oil interrupter electronic controlled reclosers, when counter readings are exceeded, they are removed from service and maintained at the station as it is more cost effective given the small number in the fleet. Worn components are replaced and the reclosers are test operated before being returned to service.

Vacuum interrupter electronic controlled reclosers are visually inspected for deficiencies and controller batteries are replaced on a time cycle. Deficiencies for these reclosers are typically related to failed controller batteries, which maintenance staff will replace, or failure of the recloser to open or close. Reclosers that fail to operate are normally removed from service and sent to the manufacturer for repair or are replaced with a spare unit if not repairable. Expenditures related to the replacement of controller batteries are captured in Section 2.3.3 Telecommunications, Monitoring, Protection & Control.

Recloser corrective maintenance accounts for approximately 10% of the total expenditure under the Stations Demand and Planned Corrective Maintenance Program. Hydro One plans to complete approximately 270 recloser corrective maintenance activities in 2028, consistent with 2023–2025 historical actual work volumes.

Breaker Corrective Maintenance

As described in DSP Section 3.2, approximately 72% of Hydro One Rate Zone breakers have exceeded their 45-year expected service life, with many metal-clad breakers now obsolete or no longer supported by manufacturers. In addition, the internal condition of approximately 38.5% of breakers is unknown because they have not recently been removed from service for the maintenance activities required to assess their condition. This combination of a mature fleet of legacy assets and a significant population with unknown internal condition underscores the importance of the proposed maintenance program for both condition discovery and asset preservation.

Most of the distribution station breakers are metal-clad. Common identified defects include breakers failing to open when required to clear system faults, breakers failing to close when required to restore power, failure of protection to operate the breaker, or failure to provide the required electrical insulation. When these defects are identified, they are addressed through corrective action.

Defective breakers will be repaired under this program, provided they are repairable and replacement parts are available. Breakers that are obsolete will be replaced with reclosers under D-SR-04 when a station refurbishment project is planned for the station.

Breaker corrective maintenance accounts for approximately 1% of the total expenditure under the Stations Demand and Planned Corrective Maintenance Program. Consistent with 2023–2025 historical actuals, Hydro One plans to complete approximately 15 planned station breaker defect corrections in 2028.

Switches & Fuses Corrective Maintenance

Approximately 12.9% of Hydro One Rate Zone station switches, or about 323 switches are in poor condition. An aging demographic contributes to an increase in the condition assessment for these assets. D-SR-03 plans to replace 75 end-of-life station switches over 2028 to 2032, but other poor condition switches and newly identified deficiencies will require test operation, lubrication, alignment and component repair through the proposed maintenance program.

For switches, common identified defects include seized bearings and failure of porcelain support insulators. These defects can cause switches to become stuck in either the open or closed position. This will cause unplanned interruptions or the extension of interruptions to repair the switches. Normally these defects are identified when the switch is operated. Where viable, defective station switches will be repaired with the application of lubrication and manual operation, or replacement of components.

Station fuses are installed upstream of the station transformer to protect it from system faults. Normally, a set of spare fuses is stored at the station for replacement when fuses operate to clear faults. Station fuses identified as defective through inspection or testing are replaced with new fuses. Common defects include fuses that fail air-flow testing and broken porcelain support insulators on fuse holders. This program also funds the replacement of fuses that have operated to clear system faults.

Switch and fuse corrective maintenance accounts for approximately 11% of the total expenditures under the Stations Demand and Planned Corrective Maintenance Program. Hydro One plans to complete approximately 120 switch and fuse defect corrections in 2028. Switch and fuse corrective maintenance is typically performed in conjunction with transformer corrective maintenance activities, allowing outages to be coordinated and work to be completed more efficiently. As discussed in the Transformer Corrective Maintenance section above, the planned increase in transformer corrective maintenance work resulting from improved Mobile Unit Substation (MUS) availability is expected to result in a corresponding increase in switch and fuse corrective maintenance volumes in 2028 compared to 2023–2027.

Mobile Unit Substation Corrective Maintenance

As described in DSP Section 3.2 subsection 3.2.2.4, eight Mobile Unit Substations (MUSs) transformers, or 24%, are in poor condition and approximately 48% are beyond their expected service life. Hydro One proposed to replace four MUSs over the 2028 to 2032 period. The remaining MUS units require preventive and corrective maintenance to preserve fleet readiness.

For MUSs, the electrical components—including transformers, reclosers, switches, and fuses—are subject to many of the same failure modes and defects as comparable equipment installed in stations. Deficiencies identified in MUS electrical equipment are addressed when the MUS is out of service.

MUS trailers are also subject to defects requiring corrective maintenance. Common issues include corrosion, tire failures, defective brakes, suspension and axle defects, landing gear and hydraulic system deficiencies, and damaged cable reels. These deficiencies are addressed when the MUS is not in operation to ensure the equipment remains safe, roadworthy, and available for deployment when required.

MUS corrective maintenance accounts for approximately 7% of the total expenditure under the Stations Demand and Planned Corrective Maintenance Program. Hydro One plans to complete approximately 30 MUS defect corrections in 2028. These forecasted work volumes are consistent with 2023–2025 historical actuals.

Other Station Assets Corrective Maintenance

For other station assets, common deficiencies identified through inspections and addressed through corrective maintenance include:

- damaged station fences, including gaps or cut fence fabric that could allow access by the public or animals;
- missing, damaged, or tampered grounding conductors;
- station yards and access roads that require additional gravel to maintain safe footing conditions and mitigate step-and-touch potential hazards;
- cracked or deteriorated concrete foundations supporting transformers or station structures;
- station service transformers exhibiting oil leaks;
- broken or damaged insulators supporting bus or other electrical equipment; and
- cracked transformer oil spill containment systems.

Other asset corrective maintenance accounts for approximately 13% of the total expenditure under the Stations Demand and Planned Corrective Maintenance Program. Hydro One plans to address approximately 350 deficiencies related to other station assets through planned corrective maintenance activities. These forecasted work volumes are consistent with 2023–2025 historical actuals.

2.1.2.2 PROGRAM EXPENDITURES

Table 4 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Stations Demand and Planned Corrective Maintenance in Distribution Sustainment Stations OM&A.

Table 4 - Stations Demand and Planned Corrective Maintenance OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Stations Demand and Planned Corrective Maintenance	13.2	14.6	13.4	12.3	12.5	16.7

The 2028 Test year expenditure for Stations Demand and Planned Corrective Maintenance OM&A is $16.7M, a $3.5M increase over 2023 actuals, and a $3.5M increase over the average of the last rate period (2023-2027).

Due to the variable nature of demand work, Hydro One generally develops forecast expenditure levels for the Stations Demand and Planned Corrective Maintenance Program based on historical averages. For most subcategories of the program, the forecasted 2028 work volumes are consistent with historical actual levels. This includes reclosers, station breakers, Mobile Unit Substations (MUSs), and other station assets, where forecasted corrective maintenance activities generally align with 2023–2025 actual experience.

The primary driver of the increase in 2028 is transformer corrective maintenance. As discussed above, historical completion volumes were constrained by limited MUS availability, which is required to facilitate transformer outages while maintaining customer service. Beginning in 2028, Hydro One will expand its MUS fleet through the Mobile Unit Substation Program as discussed in DSP Section 3.11, D-SR-02, enabling additional transformer corrective maintenance work to be completed in 2028. This work addresses deficiencies identified through station inspections and transformer oil sampling that would otherwise remain deferred.

The increase in transformer corrective maintenance will be accompanied by a corresponding increase in switch and fuse corrective maintenance, as these activities are typically bundled together to minimize outages and improve work efficiency. Together, transformer, switch, and fuse corrective maintenance account for approximately 70% of the Stations Demand and Planned Corrective Maintenance Program.

Forecast expenditures increase from $12.5M in 2027 to $16.7M in 2028, an increase of $4.2M (34%). This increase is primarily attributable to the additional transformer corrective maintenance work planned for 2028 and the associated switch and fuse corrective maintenance activities that are completed concurrently. As a result, the 2028 Test year forecast reflects an increase in maintenance activity relative to inflation-adjusted historical actuals.

2.1.3 LAND ASSESSMENT AND REMEDIATION

2.1.3.1 PROGRAM DESCRIPTION

The land assessment and remediation program addresses the environmental risk of soil contamination from distribution stations. This soil contamination has occurred as a result of the application of certain long-lasting chemicals, such as herbicides, mineral insulating oil containing PCBs, and other materials. The historical usage of these chemicals met all applicable environment regulations and guidelines at the time they were used; however, environmental regulations have changed.

These contaminated distribution stations have the potential to cause adverse effects on human health and the environment. Hydro One has assessed its stations and implemented either remedial measures to remove or otherwise manage the contamination found off-site, or on-site management controls to mitigate future off-property impacts where environmental risks are significant.

The land assessment and remediation program includes testing to identify contamination, installation of monitoring wells, the capping of sites to prevent contamination from spreading off-site, and the remediation of off-site contamination identified through testing.

In the past, complete on-site remediation within station boundaries was often not possible when off-site contamination was being addressed. Removing all on-site contamination could have damaged critical equipment or affected station operations. As a result, while Hydro One has remediated all known off-site contamination, some contamination remains on-site.

This program enables Hydro One to operate in an environmentally responsible manner that minimizes the risk to human health and the environment and remains in compliance with applicable regulations set by the Ministry of the Environment, Conservation and Parks.

2.1.3.2 PROGRAM EXPENDITURES

Table 5 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Land Assessment and Remediation in Distribution Sustainment Stations OM&A.

Table 5 - Land Assessment and Remediation OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Land Assessment and Remediation OM&A	0.3	0.8	0.4	0.5	0.5	0.3

The 2028 Test year expenditure for Land Assessment and Remediation is $0.3M, equal to 2023 actuals, and a $0.2M decrease below the average of the last rate period (2023-2027).

Hydro One develops forecast expenditure levels for the Land Assessment and Remediation Program based on the number of remaining high-risk sites requiring contamination monitoring and the estimated cost of maintaining those monitoring programs, informed by historical work plans and experience.

The majority of remediation work has now been completed, and Hydro One has remediated all known off-site contamination. As a result, the program has transitioned from active remediation to the ongoing management and monitoring of residual on-site impacts. Remaining on-site impacts are managed through groundwater monitoring programs and site-specific risk management measures rather than active remediation. The objective of the program from 2028 onward is to ensure that these residual impacts continue to be appropriately monitored and managed to prevent potential off-site migration. Monitoring will remain in place until the affected sites are subject to future capital investments, at which time any remaining impacts will be fully remediated.

The 2028 Test year forecast reflects the completion of all known off-site remediation activities and the continued need for on-site monitoring and management at a limited number of stations. As a result, the 2028 expenditure forecast is consistent with 2023 actual expenditures and is $0.2M lower than the 2027 Bridge Year forecast.

2.2 LINES

Hydro One owns, operates and maintains approximately 126,000 circuit km of distribution lines province-wide to deliver power to Hydro One customers. Distribution lines are constructed on road allowances where possible, or on Hydro One's rights of way and consist of poles, cross arms, conductors, line transformers, and sectionalizing devices. Lines Sustainment OM&A covers expenditures required to maintain these assets.

The Lines Sustainment OM&A investments are divided into six programs, the first three of which constitute demand-driven work that is largely outside of Hydro One's control:

- **Trouble Calls (section 2.2.1):** Activities required to respond to unplanned outages, address identified public safety issues, and resolve service issues required to restore power and maintain reliable operations of the distribution system;
- **Underground Cable Locates (section 2.2.2):** Activities required to identify and mark Hydro One's underground infrastructure to support safe excavation and prevent damage to utility assets, in response to third-party requests;

- **Disconnects and Reconnects (section 2.2.3)**: The temporary disconnection and reconnection of customer electrical service to enable safe maintenance, repair, or construction work on customer-owned equipment;
- **Line Maintenance (section 2.2.4)**: Activities required to maintain the lines equipment and patrol the distribution system;
- **Waste Management (section 2.2.5):** Activities required to manage waste in compliance with environmental regulations; and
- **Other Services (section 2.2.6)**: Activities required to respond to customer inquiries, rent idle transmission lines, track service quality indicators, fund specific community events, and complete joint use audits.

Table 6 sets out planned expenditures for the 2028 Test year, along with the forecast and actual spending levels for the Bridge Year (2027) and Historical Period (2023-2026), for Sustainment Lines OM&A. Sections 2.2.1 to 2.2.6 provide more detailed descriptions of the work and expenditures in each program.

Table 6 - Distribution Sustainment Lines OM&A Hydro One Networks ($M)

Sustainment Lines OM&A	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Trouble Calls	92.5	83.2	92.1	91.3	91.9	93.7
Underground Cable Locates	25.3	28.7	27.2	30.8	31.9	33.0
Disconnects/ Reconnects	35.2	30.6	33.3	35.4	33.4	34.0
Line Maintenance	10.7	9.1	6.5	18.0	18.4	35.5
Waste Management	24.3	34.2	5.8	5.6	4.3	4.4
Other Services	16.1	16.8	14.9	15.6	16.6	18.2
Total	**204.0**	**202.6**	**179.8**	**196.8**	**196.5**	**218.8**

The 2028 Test year expenditure for Lines Sustainment OM&A is $218.8M, a $14.8M increase over 2023 actuals, and a $22.9M increase over the average of the last rate period (2023-2027). The increase in the 2028 Test year forecast relative to the 2027 Bridge Year is primarily attributable to Trouble Calls and Line Maintenance programs, which are

discussed further in sections 2.2.1 and 2.2.4 below. The 2028 Test Year expenditure for demand programs is based on the two-year historical average, escalated for inflation.

2.2.1 TROUBLE CALLS

2.2.1.1 PROGRAM DESCRIPTION

The Trouble Call program addresses the restoration of service to customers impacted by an unplanned power interruption. Such unplanned power interruptions on the distribution system are largely due to line component failures or contact with vegetation. Depending on the specific circumstances, these interruptions can vary in size, from impacting a few customers for brief periods of time to impacting thousands of customers for several hours. Trouble calls may also be used to respond to customer complaints or to correct defects on the distribution system that present an imminent safety concern or could result in an imminent service interruption.

Hydro One must address these trouble calls in order to comply with legal and regulatory requirements, to address known public safety hazards and to maintain reliable service in accordance with good utility practice. Hydro One's performance in responding to trouble calls is reflected by service quality indicators specified in Section 7 of the DSC as discussed in Exhibit A-05-03.

When the resolution of a trouble call involves the repair of an affected component or the clearing of fallen vegetation, such work is captured in this program. If the resolution involves the replacement of damaged or defective equipment, the replacement is charged to the Trouble Calls and Storm Damage capital program as discussed in DSP Section 3.11, D-SR-05.

2.2.1.2 PROGRAM EXPENDITURES

Table 7 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Trouble Calls in Distribution Sustainment Lines OM&A.

Table 7 - Trouble Calls OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Trouble Calls	92.5	83.2	92.1	91.3	91.9	93.7

The 2028 Test year expenditure for Trouble Calls is $93.7M, a $1.2M increase over 2023 actuals, and a $3.5M increase over the average of the last rate period (2023-2027).

The Trouble Calls program is reactive in nature, with work volumes driven by factors outside Hydro One's control, including severe weather events, equipment failures, and customer complaints. As a result, Hydro One forecasts expenditures for this program based on historical average work volumes and costs. Forecasted 2028 work volumes are consistent with historical actual and bridge-year forecasts as per Table 8 below.

Table 8 - Trouble Calls OM&A (Units)

Program	Historical				Bridge Year	Test year
	Actual	Actual	Actual	Forecast	Forecast	Forecast
	2023	2024	2025	2026	2027	2028
Trouble Calls	49,510	47,144	51,661	47,000	49,400	49,400

2.2.2 UNDERGROUND CABLE LOCATES

2.2.2.1 PROGRAM DESCRIPTION

The underground cable locates program provides the service of locating and marking Hydro One’s underground plant for customers and contractors who request this information. Responding to these requests reduces safety risks associated with excavation near underground cables and helps prevent damage to critical infrastructure. This service is provided in accordance with the Electrical Safety Authority’s “Guidelines for Excavating in the Vicinity of Distribution Lines” and in order to comply with legal requirements set out in Ontario Regulation 22/04.

This program minimizes utility equipment damage while providing worker safety to those excavating in proximity to buried utility plant. To encourage the use of this service, the program costs are not recovered through end user charges. This approach is consistent with the practice followed by other regulated utilities, including cable TV, telephone service and natural gas utilities.

2.2.2.2 PROGRAM EXPENDITURES

Table 9 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Underground Cable Locates OM&A.

Table 9 - Underground Cable Locates OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Underground Cable Locates	25.3	28.7	27.2	30.8	31.9	33.0

The 2028 Test year expenditure for Underground Cable Locates is $33.0M, a $7.7M increase over 2023 actuals, and a $4.2M increase over the average of the last rate period (2023-2027).

Due to the variable nature of this demand work, Hydro One forecasts expenditures based on historical average volumes and costs with adjustments incorporating assumptions related to projected external service provider cost increases and the expected influence of government infrastructure spending on workload. The proposed spending for the Test year is based on an expected volume of 254,000 cable locate requests per year, which is consistent with recent demand as per Table 10.

Table 10 - Underground Cable Locates OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Underground Cable Locates	246,048	253,891	245,290	254,000	254,000	254,000

The increase in expenditures is primarily attributable to higher third-party costs and the impacts of the Getting Ontario Connected Act ("GOCA"). GOCA introduced stricter performance requirements and penalties for failure to meet locate request timelines, which increased demand for locate services across the utility sector and contributed to higher costs. For more information, see Exhibit G-01-01, Section 5.12.

2.2.3 DISCONNECTS / RECONNECTS

2.2.3.1 PROGRAM DESCRIPTION

The Disconnects and Reconnects program addresses customer requests to temporarily isolate customer-owned assets from the distribution system so that work can be safely performed on those assets. Providing electrical isolation helps protect customers, contractors, Hydro One personnel, and members of the public from the risks associated with working on energized equipment.

In accordance with Hydro One's Conditions of Service, customers may receive this service once per year at no charge. Providing this service encourages customers to properly maintain their electrical facilities and undertake that work in a safe manner.

Hydro One is required to respond to these requests in accordance with its Conditions of Service. Hydro One's performance in providing service disconnects and reconnects is reflected in the service quality indicators set out in Section 7 of the Distribution System Code, as discussed in Exhibit A-05-03.

2.2.3.2 PROGRAM EXPENDITURES

Table 11 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Disconnects / Reconnects in Distribution Sustainment Lines OM&A.

Table 11 - Disconnects / Reconnects OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Disconnects / Reconnects	35.2	30.6	33.3	35.4	33.4	34.0

The 2028 Test year expenditure for Disconnects / Reconnects is $34.0M, which is $1.2M below 2023 actuals, and a $0.4M increase over the average of the last rate period (2023-2027). This reflects the lower volumes relative to the unusually high number of customer requests experienced in 2023, which was likely impacted by COVID.

Disconnects / Reconnects expenditures are driven by the volume of customer requests. Due to the variable nature of demand work, Hydro One develops investment levels based on forecast volumes and costs using observed historical averages.

The proposed 2028 Test year work program is based on 28,100 disconnects and reconnects requests per year as per Table 12.

Table 12 - Disconnects / Reconnects OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Disconnects / Reconnects	32,541	26,901	29,295	30,000	28,100	28,100

2.2.4 LINE MAINTENANCE

The Line Maintenance program includes inspection and corrective maintenance on all overhead, underground, and submarine distribution assets, as well as preventive

maintenance of overhead switches and insulators. Hydro One conducts four types of inspections on its distribution lines, as discussed in section 2.4.4.1 and two types of preventive maintenance in addition to corrective maintenance, as discussed in 2.4.4.2.

Figure 4 below provides a breakdown of the 2028 work program expenditures allocated across activities, with further details on each provided in the sections that follow.

The 2028 Line Maintenance program reflects a renewed focus on and increase in planned inspection and maintenance activities to support the safe and reliable operation of distribution line assets. The specific activities and expenditure drivers are described in the sections that follow.

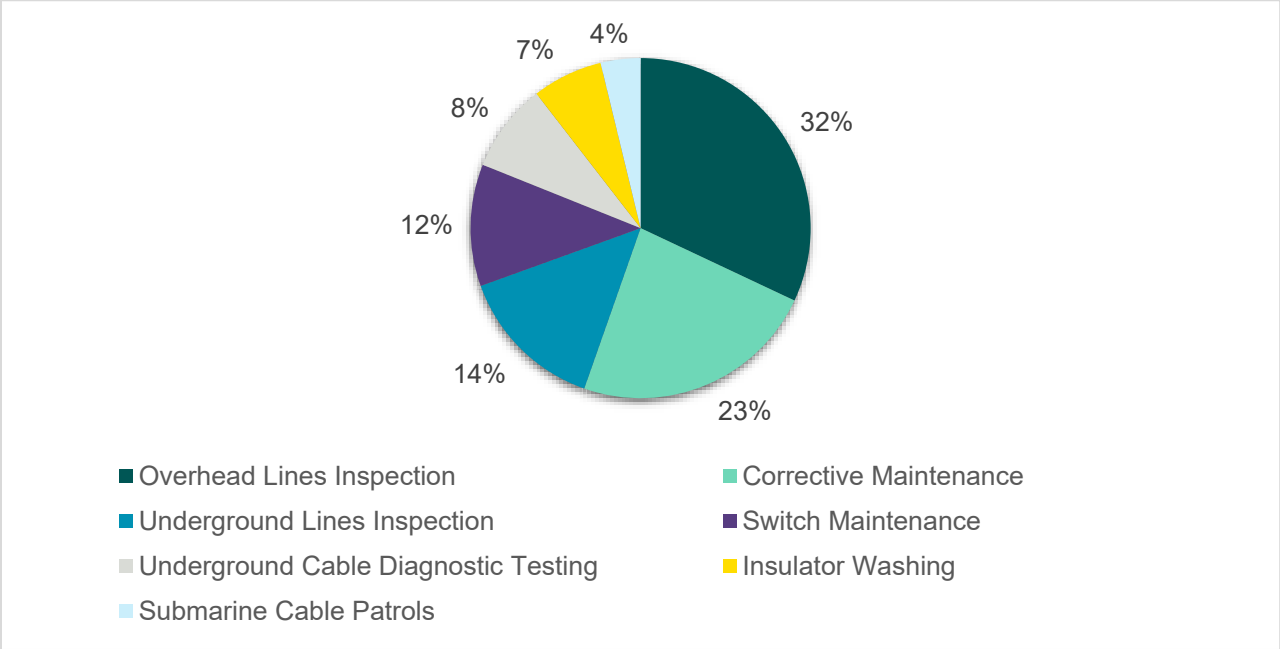

Figure 4: Breakdown of 2028 Line Maintenance Expenditures

2.2.4.1 PROGRAM DESCRIPTION – INSPECTIONS

Hydro One inspects its distribution lines and associated equipment in accordance with the minimum inspection requirements set out in Appendix C of the DSC. These inspections identify defects, deteriorated or damaged equipment, public safety hazards, and other

abnormal conditions that could affect the safe and reliable operation of the distribution system. The data collected during the inspections also provides critical input into Hydro One's asset condition assessments, which are discussed in DSP Section 3.2. The asset condition assessment of poles, cross arms, underground cables, and submarine cables are compiled based on the data collecting in these inspection and testing activities. The corrective maintenance program is also prioritized based on the defects collected in these inspections.

Overhead Lines Inspection

Overhead line patrols inspect all Hydro One owned poles, overhead conductors, cross arms, insulators, and pole mounted equipment, as well as third-party-owned poles that support Hydro One-owned assets. These minimum inspection frequencies are prescribed by Appendix C of the Distribution System Code, which requires overhead distribution equipment to be inspected at least every three years in urban areas and every six years in rural areas. Historically, these patrols were completed as part of the vegetation management inspection process, however, as vegetation management cycles increased, their timing no longer consistently aligned with the minimum inspection requirements. Beginning in 2028, overhead line patrols will be completed separately from vegetation management inspections to ensure that the required asset inspections are completed within the DSC timelines. Overhead line inspections account for approximately 32% of the Lines Maintenance Program expenditures in the 2028 Test year, with approximately 357,800 locations forecast to be inspected annually, consistent with previous accomplishments.

If a public safety hazard is identified, a trouble call is initiated to address the issue. Defects that can be addressed as a planned activity are recorded for later prioritization. Simple defects, such as missing signage, are fixed at the time of patrol.

Table 13 - Overhead Lines Inspections OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Overhead Lines Inspections (# of Poles)	0	0	0	0	0	357,800[2]

Underground Lines Inspection

Underground line patrols inspect Hydro One owned pad-mounted transformers, pad-mounted switches, and the surrounding area to ensure there are no exposed cables. These inspections are performed on a six-year cycle in rural locations and on a three-year cycle in urban locations. If the inspection identifies a public safety hazard, a trouble call is initiated to have the issue fixed. Defects that can be addressed as a planned activity are recorded for later prioritization. Simple defects, such as missing signage, are fixed at the time of patrol.

The Underground Cable Diagnostic Program introduces targeted testing of underground cables that are at, or approaching, the end of their expected service life in the poorest-performing areas of the distribution system. Diagnostic testing will provide detailed information on cable insulation, splices, and overall asset condition to determine whether continued operation, rejuvenation, or replacement is the most appropriate course of action. The resulting data will support the risk-informed prioritization of investments under the Underground Cable Replacement and Rejuvenation Program (D-SR-15) and help Hydro One transition from a reactive, run-to-failure approach to a proactive asset management strategy that reduces the likelihood of unplanned customer interruptions.

Underground lines inspections and diagnostics account for approximately 22% of the total Lines Maintenance Program expenditures for the 2028 Test year. The proposed work

[2] To meet DSC code requirements, urban locations are inspected every 3 years, and rural locations are inspected every 6 years. Furthermore, there are additional poles owned by Bell Canada that are required to be inspected by Hydro One. Therefore, the total annual number of poles inspected is 357,800.

program covers the inspection of approximately 17,700 locations annually as well as the diagnostic testing of approximately 1,100 segments annually, as per Table 14. The forecast volume is based on the number of in-service underground equipment and their required inspection cycles.

Table 14 - Underground Lines Inspections and Diagnostics OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Underground Lines Inspections	14,834	15,306	10,738	17,688	17,688	17,688
Underground Cable Diagnostic Testing	0	0	0	0	0	1,127

Submarine Cable Patrols

As described in DSP Section 3.2 subsection 3.2.3.3, approximately 10% or 1,350 submarine cables are in poor condition and approximately 300 additional units per year are expected to be identified as poor condition through inspections. Submarine cable patrols inspect the integrity of Hydro One owned underwater cables. These patrols will visually inspect the condition of the cable and the mechanical protection at the load and source side shorelines. Sometimes time domain reflectometry (TDR) tests are also performed if the cable is not visible to assess any damage. These inspections are performed on a six-year cycle. If the inspection identifies a public safety hazard, a trouble call is initiated to have the issue fixed. Defects that can be addressed as a planned activity are recorded for later prioritization. Hydro One is increasing units in 2026 to maintain compliance with regulatory requirements. Simple defects, such as missing signage, are fixed at the time of patrol.

Submarine cable patrols account for approximately 4% of the total Lines Maintenance Program expenditures for the 2028 Test year. The proposed work program in Table 15 below covers the patrol of approximately 2,300 submarine cables annually. The forecast

volume is based on the number of in-service submarine cables and their required inspection cycles.

Table 15 - Submarine Cable Patrols OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Submarine Cable Patrols	1,852	2,089	900	4,343	2,287	2,287

2.2.4.2 PROGRAM DESCRIPTION – MAINTENANCE

Preventive maintenance of line equipment is required to mitigate the risk of failures by ensuring the safe and reliable operation of equipment. Switch maintenance and insulator washing are the two types of preventive maintenance planned in the test year. A third type of line equipment maintenance planned in the test year is corrective maintenance which is focused on the repair and replacement of minor defective components.

Sustaining these line assets ensures the continued operation of the distribution system which plays an important role in maintaining customer reliability. The outcomes this program will achieve are as follows: Reduce the risk of equipment failure, which can impact service reliability to customers; and operate in a responsible manner that minimizes the potential of safety risks that the failure of the equipment poses to the public and Hydro One employees. The Switch Maintenance, Insulator Washing, and Corrective Maintenance sections below outline how maintenance programs mitigate equipment failure risk.

Switch Maintenance

Regular maintenance of air break switches and load break switches is required to ensure their reliable operation and reduce the risk of customer interruptions. These three-phase switches typically serve large numbers of customers and play an important role in the operation of the distribution system. Failure of a switch can result in prolonged outages and increase restoration times. The Switch Maintenance Program mitigates failure risk

through lubrication of moving components, adjustment of misaligned parts, and correction of minor defects. This maintenance helps ensure switches function as intended when needed and supports the safe and reliable operation of the distribution system. Hydro One is increasing switch maintenance units starting in 2026 to address backlog.

Switch Maintenance accounts for approximately 12% of the total Lines Maintenance Program expenditures for the 2028 Test year. The proposed work enables the maintenance of 632 three phase switches annually. This is a time-based maintenance program and the 2028 proposed volumes of work outlined in Table 16 are required to maintain Hydro One's approximately 3,500 air break and load break switches. Specifically, Hydro One plans to maintain 632 three phase switches annually in the Hydro One Network, which represents an increase over historic accomplishments. The increase is attributed to reduced historical volumes due to reprioritization of work as outlined in Exhibit E-03-01, as well as additional switches being added to the system.

Table 16 - Switch Maintenance OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Switch Maintenance	151	264	140	632	632	632

Insulator Washing

Insulators are made from materials such as porcelain or polymer that mechanically support energized conductors on cross arms and poles while preventing electrical current from flowing to ground. Pollution, contaminants, road salt and de-icing chemicals can build up on insulators over time resulting in a temporary breakdown of the insulation which can cause pole fires and outages for downstream customers. The insulator washing program is a condition-based maintenance program that removes contaminants on high impact feeders, lowering the risk of flashovers and pole fires.

Insulator Washing accounts for approximately 7% of the total Lines Maintenance Program expenditures for the 2028 Test year. The proposed work program in Table 17 below enables Hydro One to wash an average of 69,000 insulator locations per year. Though this program was suspended in the current rate period to prioritize demand-driven work and cost pressures which are discussed in Exhibit E-03-01, it will be restarted in the 2028 test year to address the safety and reliability risks that have accumulated over the historical years.

Table 17 - Insulator Washing OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Insulator Washing	0	0	0	0	0	69,000

Corrective Maintenance

Corrective maintenance of line equipment addresses minor defects identified through line inspection activities. Examples of such defects include broken guy wires, damaged insulators, and faulty lightning arresters. Deficiencies identified during line inspections are recorded and prioritized through Hydro One's investment planning process, with defects posing the greatest safety and reliability risks addressed through this program. Where feasible, corrective maintenance activities are coordinated with other planned work to improve operational efficiency. Correcting these deficiencies supports the continued safe and reliable operation of the distribution system by reducing the risk of equipment failures and mitigating potential safety hazards to the public and Hydro One personnel.

Corrective Maintenance accounts for approximately 23% of the total Lines Maintenance Program expenditures for the 2028 Test year. The proposed work program covers approximately 14,100 defect corrections per year in Hydro One Networks. As shown in Table 18 below, the planned volumes in the test year exceed historical actual levels and are intended to address the highest-priority defects within the existing defect inventory. Despite this increase, the accumulated inventory of defects is expected to

continue growing over the planning period, as defects are being identified at a faster rate than they can be corrected. The proposed program therefore prioritizes correction of those defects with the greatest potential impact on safety and reliability starting in 2026.

Table 18 - Corrective Maintenance OM&A (Units)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Corrective Maintenance	8,237	5,550	4,880	14,067	14,067	14,067

The accumulated inventory of defects is likely to increase over the course of the plan as more defects are identified annually than corrected. The highest potential impact defects will be addressed as part of this plan.

During 2023 to 2025, demand-driven work, compliance requirements and inflationary pressures constrained planned line inspection and maintenance activities and contributed to accumulated work backlogs. Beginning in 2026, Hydro One increased spending and work volumes for underground line inspections, submarine cable patrols, switch maintenance and corrective maintenance, as shown in Tables 14, 15, 16 and 18, to begin to restore required inspection and maintenance levels. Hydro One prioritizes identified defects based on their potential safety and reliability impacts.

2.2.4.3 PROGRAM EXPENDITURES

Table 19 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for the Line Maintenance in Distribution Sustainment Lines OM&A.

Table 19 - Line Maintenance OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Overhead Lines Inspections	0.0	0.0	0.0	0.0	0.0	11.3
Underground Lines Inspections and Diagnostics	4.2	3.9	2.5	4.8	4.9	8.0
Submarine Cable Patrols	1.0	1.0	0.5	1.3	1.3	1.3
Switch Maintenance	0.9	1.4	0.9	4.0	4.0	4.1
Insulator Washing	0.0	0.0	0.0	0.0	0.0	2.4
Corrective Maintenance	4.6	2.8	2.6	8.0	8.1	8.3
Line Maintenance Total	**10.7**	**9.1**	**6.5**	**18.0**	**18.4**	**35.5**

The 2028 test year expenditure for Line Maintenance is $35.5M, a $24.8M increase over 2023 actuals, and a $23.0M increase over the average of the last rate period (2023-2027).

Hydro One develops forecast expenditure levels for the Line Maintenance Program based on known defect volumes, minimum inspection requirements, and established preventive maintenance cycles. The selection and prioritization of line maintenance investments is guided by the investment planning process described in DSP Section 3.7.

The increase relative to historical years reflects Hydro One's return to the required levels of line inspection and maintenance activities, which were reprioritized during the historical period to address demand-driven requirements and cost pressures in other programs, including Trouble Calls (Section 2.2.1), Underground Cable Locates (Section 2.2.2), and Service Disconnects and Reconnects (Section 2.2.3).

The 2028 test year forecast for this program of $35.5M is $17.1M (93%) higher than the 2027 Bridge Year forecast of $18.4M. This increase is driven by several factors:

- **Overhead Lines Inspections**: The transfer of Distribution Line Patrols from Vegetation Management to Lines Maintenance accounts for 66% of the Lines Maintenance expenditure increase between 2027 and 2028.

- **Underground Cable Diagnostics**: The introduction of the Underground Cable Diagnostic Program in 2028 accounts for approximately 18% of the increase in Line Maintenance expenditures from 2027 to 2028. The program will target underground cables that are at, or approaching, expected service life in the poorest-performing areas for diagnostic testing. The resulting condition data, including information regarding cable insulation and splices, will support the prioritization of replacement and refurbishment investments under the Underground Cable Replacement Program (DSP Section 3.11, D-SR-15), as Hydro One transitions from a historical run-to-failure approach to a planned asset management approach for these assets. As described in DSP Section 3.2 subsection 3.2.1.2, approximately 30% of the underground cable population in the distribution system is beyond ESL in 2025 and the number of underground cable interruptions has increased by approximately 60% since 2016. The lack of internal condition information and worsening reliability support diagnostic testing in poor-performing areas. Testing determines whether continued operation, rejuvenation or replacement is appropriate. Reactive repair also remains necessary for failures arising before planned intervention. This work will enable Hydro One to identify and address deteriorated underground cable assets in high-priority areas before they fail, reducing the risk of unplanned customer interruptions.
- **Insulator Washing**: The resumption of this program accounts for approximately 13% of the Lines Maintenance expenditure increase between 2027 and 2028. This program removes contamination on high impact feeders, lowering the risk of flashovers and pole fires. Though this program was suspended in the current rate period to prioritize demand-driven work and cost pressures which are discussed in Exhibit E-03-01, resuming this activity in the 2028 test year is required to address the safety and reliability risks that have accumulated over the historical years.
- **Corrective Maintenance**: The increase accounts for roughly 4% of the Lines Maintenance expenditure increase between 2027 and 2028 and is necessary to address the current accumulated inventory of over 400,000 identified defects on the system. The highest priority defects will be addressed over the plan based on their potential impact to reliability and safety outcomes.

2.2.5 WASTE MANAGEMENT

2.2.5.1 PROGRAM DESCRIPTION

Effective management of waste generated through the operation and maintenance of distribution assets is required to protect human health and the environment and ensure compliance with applicable environmental regulations. The Waste Management Program manages all waste streams associated with distribution operations and maintenance activities, including insulating oil, hydraulic oil, lead, cadmium, mercury, and other regulated materials. Program activities include collection, cleanup, notification, documentation, storage, transportation, containment, inspection, tracking, reporting, and disposal of waste materials, as well as site restoration activities where required.

This program enables Hydro One to operate in an environmentally responsible manner by minimizing environmental and public health risks associated with waste handling and disposal. It also ensures Hydro One remains compliant with applicable legislative and regulatory requirements governing the management of hazardous and non-hazardous waste streams.

Over the historical period, years 2023 and 2024 in particular, Hydro One incurred a significant one-time expenditures associated with meeting the PCB deadline, where testing and inspecting of oil-filled equipment for PCB content was undertaken, in order to comply with the end-of-use deadlines established under the federal PCB Regulations (SOR/2008-273), made pursuant to the *Canadian Environmental Protection Act, 1999*. These regulations, administered by Environment and Climate Change Canada, require that electrical equipment containing polychlorinated biphenyls (PCBs) at concentrations equal to or greater than 50 mg/kg be removed from service by the end of 2025. Hydro One is on track to meet the federal deadline by 2026.

Waste management accounts for approximately 2% of the total Lines Program expenditures for the 2028 test year. As the PCB obligations have largely been met and are expected to conclude by year end 2026, the work volumes in this program are forecasted to return to steady state in 2027 and beyond.

2.2.5.2 PROGRAM EXPENDITURES

Table 20 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Waste Management in Distribution Sustainment Lines OM&A.

Table 20 - Waste Management OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Waste Management	24.3	34.2	5.8	5.6	4.3	4.4

The 2028 test year expenditure for Waste Management is $4.4M, a $19.9M decrease relative to 2023 actuals, and a $10.4M decrease relative to the average of the last rate period (2023-2027).

Hydro One develops investment levels for the Waste Management program based on forecast volumes and costs using observed historical averages. The 2028 Test year is based on forecasts for waste management excluding all work related to PCB waste. Accordingly, the 2028 Test year forecast expenditure of $4.4M is consistent with the 2027 Bridge Year of $4.3M and significantly lower than historic actuals in 2023 of $24.3M and 2024 of $34.2M, which reflected significant one-time expenditures associated with meeting the PCB deadline.

2.2.6 OTHER SERVICES

2.2.6.1 PROGRAM DESCRIPTION

Certain support activities are required to address operational, regulatory, engineering, and administrative requirements that are not addressed through other distribution OM&A programs. The Other Services Program includes a range of activities that support the operation of Hydro One's distribution business and enable the utility to meet its regulatory, operational, and customer service obligations.

The program consists of the following primary components:

- **Investigations and Data Collection**: This work supports requests for detailed information related to distribution station and line assets. Activities include investigations and data collection required to assess asset condition, address public and employee safety concerns, respond to unacceptable system performance, support audits of joint-use facilities, and provide information required to address customer reliability concerns.
- **Miscellaneous Services**: This work includes a variety of ongoing operational and regulatory activities, including pole rental arrangements with Local Distribution Companies ("LDCs") where Hydro One equipment is attached to LDC-owned poles, switching requests performed by LDCs, the collection and reporting of service quality indicators to the Ontario Energy Board, payments to the Electrical Safety Authority for regulatory oversight activities, and engineering and environmental support services.
- **Transmission Idle Lines Rental:** This work supports Hydro One Distribution's use of transmission facilities to deliver electricity to customers at distribution voltages and includes annual rental payments to Hydro One Transmission for access to those facilities.
- **Small External Demand**: This work supports requests from customers to complete third party switching, address inquiries on processes, inspection of joint use attachments to ensure compliance with Regulation 22/04, execution of large vessel moves, and other demand work such as hold-a-pole or install cover-up.
- **Community Events:** This includes the costs associated with providing Electrical Safety Presentations, as well as the International Plowing Match.

2.2.6.2 PROGRAM EXPENDITURES

Table 21 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Other Services in Distribution Sustainment Lines OM&A.

Table 21 - Other Services OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Other Services	16.1	16.8	14.9	15.6	16.6	18.2

The 2028 Test year expenditure for Lines Other Services is $18.2M, a $2.1M increase over 2023 actuals, and a $2.2M increase over the average of the last rate period (2023-2027).

Several components of this program comprise of fixed obligations such as idle line rental payments and miscellaneous services described above. Community events are controllable costs that generally increase based on inflation. Demand programs such as Small External Demand are generally variable and difficult to forecast. Therefore, for all three program components historical spend adjusted for inflation is generally utilized to forecast future costs. The increase between the 2028 Test year and the 2027 Bridge Year is primarily driven by:

- **Community Events**: The increase in the Community Events program is due to the resumption of events that were suspended from 2025-2027. These community events are necessary to ensure sufficient public awareness of electrical safety considerations as well as ongoing community engagement.
- **Small External Demand:** Actual program expenditures from 2023 to 2025 were offset by approximately $1M in annual customer contributions, resulting in lower net expenditures. This recent level of customer contributions is not consistent with longer-term historical experience. Accordingly, forecasts for 2026 to 2028 have assumed no customer contributions, resulting in higher forecast expenditures relative to recent actuals.

2.3 METERS, TELECOM AND PROTECTION & CONTROL

Distribution Sustainment Meters, Telecommunications and Protection & Control OM&A activities are required to maintain the systems and technologies that support energy measurement, billing, system monitoring, and distribution system operations. These activities ensure the continued reliability, accuracy, and functionality of Hydro One's metering, telecommunications, protection, control, and grid modernization assets, while supporting regulatory compliance and customer service obligations.

The program consists of five categories of work:

- **Retail Revenue Meters (section 2.3.1):** This includes support for meter sampling, support for replacement of failed and end-of-life meters and communication equipment, inventory and logistics support for field operations, planning and engineering activities, routine maintenance of AMI 2.0 assets, and ongoing monitoring and resolution of network performance issues. These activities are required to maintain the accuracy, reliability, performance, and regulatory compliance of Hydro One's retail metering system.
- **Wholesale Revenue Meters (section 2.3.2)**: This includes support for routine and corrective maintenance of wholesale revenue metering assets and supports Independent Electricity System Operator ("IESO") registration and inspection requirements.
- **Telecommunications, Monitoring, Protection & Control (section 2.3.3)**: This includes preventive and corrective maintenance of protection and control equipment, as well as leasing third-party telecommunications circuits and services. These services support the collection of loading data and enable the monitoring, operation, and remote control of sectionalizing switches and electronic reclosers across the distribution system.
- **Advanced Metering Infrastructure (AMI) 2.0 (section 2.3.4)**: This includes server hosting, software maintenance, training, subject matter expertise, and temporary field meter reading activities required to maintain billing quality during the transition from AMI 1.0 to AMI 2.0.

- **Distributed Intelligence and Distribution Automation ("DIDA") (section 2.3.5)**: This supports the operation and maintenance of the Distributed Intelligence capabilities deployed through Hydro One's Distributed Intelligence and Distribution Automation platform and applications (see DSP Section 3.11 D-SR-12 for additional detail).

Table 22 below provides an annual breakdown of the programs within Hydro One's Meters, Telecom and Control OM&A expenditures. Sections 2.3.1 to 2.3.5 provide more detailed descriptions of the work and expenditures in each program.

Table 22 - Summary of Meters, Telecom, Protection & Control OM&A ($M)

Meters, Telecom & Control OM&A	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Retail Revenue Meters	10.7	10.4	9.5	12.5	12.5	15.1
Wholesale Revenue Meters	2.2	2.0	2.4	3.1	3.0	3.2
Telecommunications, Monitoring, Protection & Control	5.9	5.9	7.1	6.9	7.3	7.1
AMI Infrastructure	1.7	1.8	1.8	3.1	2.7	4.1
Distributed Intelligence and Distribution Automation (DIDA)	0.0	0.0	0.0	4.1	0.0	6.0
Total	**20.6**	**20.1**	**20.8**	**29.7**	**25.5**	**35.4**

The 2028 Test year expenditure for Meters, Telecom, and Protection & Control is $35.4M, a $14.8M increase over 2023 actuals, and a $12.1M increase over the average of the last rate period (2023-2027). The increase in the 2028 Test year is primarily attributable to the Retail Revenue Meters, AMI Infrastructure and DIDA programs, which are discussed below in sections 2.3.1, 2.3.4 and 2.3.5, respectively.

2.3.1 RETAIL REVENUE METERS

2.3.1.1 PROGRAM DESCRIPTION

Hydro One's retail revenue metering program is responsible for the inspection, testing, maintenance, and verification of retail revenue meters in accordance with applicable regulatory requirements. Hydro One uses two categories of retail revenue meters based on customer demand: approximately 1.5 million smart meters serving residential and other customers with an average monthly demand of 50 kW or less, and approximately 10,900 meters serving customers whose average monthly demand exceeds 50 kW.

Retail revenue meters must be operated, maintained, and verified in accordance with federal legislation, including the *Electricity and Gas Inspection Act* and the *Weights and Measures Act*, as well as the OEB's Standard Supply Service Code, the Distribution System Code, and IESO market rules.

Hydro One is currently implementing its Advanced Metering Infrastructure 2.0 ("AMI 2.0") program, a multi-year initiative approved in EB-2021-0110 to replace the legacy AMI 1.0 system with next-generation smart meters and communications network equipment across its service territory. Deployment commenced in 2025 and is expected to continue through 2029. Additional information is provided is provided DSP Section 3.11, D-SR-12.

The program includes the management of Advanced Metering Infrastructure ("AMI") equipment inventories, instrument transformers, and metering accessories to ensure sufficient stock is available to support meter reverification activities, service upgrades, emergency response, and the replacement of failed, defective, damaged, or end-of-life metering assets. It also includes planning and engineering activities required to maintain regulatory compliance, routine maintenance of AMI 2.0 meters and communications network equipment and ongoing monitoring of network performance. These activities enable Hydro One to identify, prioritize, and resolve metering and communications issues in a timely manner, supporting the accuracy, reliability, and compliance of its retail metering system.

2.3.1.2 PROGRAM EXPENDITURES

Table 23 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Retail Revenue Meters in Distribution Sustainment Meters, Telecom & Control OM&A.

Table 23 - Retail Revenue Meters ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Retail Revenue Meters	10.7	10.4	9.5	12.5	12.5	15.1

The 2028 Test year expenditure for Retail Revenue Meters is $15.1M, a $4.4M increase over 2023 actuals, and a $3.9M increase over the average of the last rate period (2023-2027). Hydro One develops Retail Revenue Meter OM&A expenditure forecast levels to meet regulatory requirements and to support the reliable and effective operation of its AMI infrastructure.

The increase in Retail Revenue Meters expenditure is driven by additional operational activities associated with the expanded functionality of the AMI 2.0 system. These activities support improved billing reliability, enhanced system monitoring, and overall network performance:

- **Battery backup maintenance for network devices:** AMI 2.0 includes battery backup capability for network devices, a reliability feature that was not available under AMI 1.0. This capability enables continued meter communications during power interruptions, supporting billing continuity and outage awareness. Maintaining this functionality requires ongoing inspection, testing, and replacement of battery assets.
- **Analytics and network monitoring:** AMI 2.0 provides more granular visibility into meter and network performance, enabling Hydro One to proactively identify and address issues such as high-temperature conditions, meter tampering, communication failures, and other anomalies. Realizing these benefits requires

additional system support, data management, monitoring, and operational oversight activities to analyze information, investigate issues, and implement corrective actions in a timely manner.

2.3.2 WHOLESALE REVENUE METERS

2.3.2.1 PROGRAM DESCRIPTION

The Wholesale Revenue Meters program provides support for preventative and corrective maintenance, meter re-sealing and verification, trouble call response, IESO registration, and routine maintenance as required by the IESO market rules and the Federal Electricity Gas and Inspection Act. Wholesale revenue meters are also subject to IESO inspections to verify compliance of metering installations with technical specifications contained in the market rules. Any identified deficiencies must be corrected within the prescribed time limits. Hydro One is the metered market participant for 430 wholesale revenue meter installations.

The program provides servicing for all wholesale revenue meter installations to comply with IESO market rules and Measurement Canada's Electricity Gas and Inspection Act. Hydro One develops investment levels for the program based on IESO wholesale metering requirements, the number of wholesale metering points, and historical maintenance levels for corrective maintenance.

2.3.2.2 PROGRAM EXPENDITURES

Table 24 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Wholesale Revenue Meters in Distribution Sustainment Meters OM&A.

Table 24 - Wholesale Revenue Meters OM&A ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Wholesale Revenue Meters	2.2	2.0	2.4	3.1	3.0	3.2

The 2028 Test year expenditure for Wholesale Revenue Meters is $3.2M, a $1.0M increase over 2023 actuals, and a $0.6M increase over the average of the last rate period (2023-2027).

Hydro One develops expenditure levels for the Wholesale Revenue Meters program based on IESO wholesale metering requirements, the number of wholesale metering installations, and historical corrective maintenance experience. The Wholesale Revenue Meters forecast expenditures for the 2028 Test year of $3.2M are $1.0M (47%) higher than 2023 actual expenditures, and $0.2M higher (7%) than the 2027 Bridge expenditures. The increase is primarily driven by a significant rise in the number of required Instrument Transformer ("IT") spot checks, which are performed to comply with IESO market rules and the *Electricity and Gas Inspection Act*. The number of required IT spot checks is forecast to increase from 69 in 2023 to 341 in 2028. As a result, forecast expenditures for the program are higher than historical expenditure levels and reflect the increased activities required to maintain compliance with applicable regulatory and market requirements.

2.3.3 TELECOMMUNICATIONS, MONITORING, PROTECTION AND CONTROL

2.3.3.1 PROGRAM DESCRIPTION

The Telecommunications, Monitoring, Protection and Control program is required to maintain and troubleshoot protection and control assets. These assets support remote monitoring, data collection, and system operation, and play a critical role in protecting and restoring the distribution system following power system events. The program includes the repair, recalibration, and replacement of defective protection and control equipment, the collection of event records for protection system analysis, and planned battery replacement for protection and control devices. These activities ensure that protection and control systems continue to provide real-time operational data, enable the remote operation of distribution equipment, and capture detailed event information to support post-event analysis, system restoration, and ongoing reliability improvements.

2.3.3.2 PROGRAM EXPENDITURES

Table 25 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Telecommunications, Monitoring, Protection and Control in Distribution Sustainment Meters, Telecom & Control OM&A.

Table 25 - Telecommunications, Monitoring, Protection and Control ($M)

Program	Historical				Bridge Year	Test year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Telecommunications, Monitoring, Protection & Control	5.9	5.9	7.1	6.9	7.3	7.1

The 2028 Test year expenditure for Telecommunications, Monitoring, Protection and Control is $7.1M, a $1.2M increase over 2023 actuals, and a $0.5M increase over the average of the last rate period (2023-2027). Hydro One develops expenditure levels for the Telecommunications, Monitoring, Protection and Control program based on the number of installed protection and control devices and historical program costs.

The expenditures in this program increased in 2025-2027 due to Communicating Faulted Circuit Indicator (CFCI) troubleshooting and firmware upgrades. Starting in 2028, the program must address higher volumes of work due the planned addition of smart devices and CFCIs as outlined in Distribution Automation and Sectionalization Program (DSP Section 3.11, D-SS-05) and DER Hosting Capacity Program (DSP Section 3.11, D-SS-07). This addition has required an increase in the protection and control troubleshooting support required as well as an increase in the preventative (battery replacement) and demand corrective spending that is forecasted to increase in 2028 and beyond to ensure these devices work as expected.

2.3.4 ADVANCED METERING INFRASTRUCTURE (AMI 2.0)

2.3.4.1 PROGRAM DESCRIPTION

As noted above, the AMI 2.0 program is currently in progress and is scheduled for completion in 2029 as discussed in DSP Section 3.11, D-SR-12. OM&A funding is required until 2029 to sustain and support the program including:

- **Server Hosting Fees:** Cloud hosting, data storage, system processing and disaster recovery services.
- **Software Maintenance Fees:** Vendor licensing, software support, security patches, upgrades, and ongoing maintenance.
- **Professional Services:** Specialized vendor and consulting support for solution integration, testing, project delivery, training, and business process implementation.
- **Hydro One Subject Matter Expertise**: Internal resources providing metering, telecom, IT, operational, cybersecurity, and business expertise to support the program

2.3.4.2 PROGRAM EXPENDITURES

Table 26 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for AMI Infrastructure in Distribution Sustainment Meters, Telecom & Control OM&A.

Table 26 - AMI Infrastructure

Program	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
AMI Infrastructure	1.7	1.8	1.8	3.1	2.7	4.1

The 2028 Test year expenditure for AMI Infrastructure is $4.1M, a $2.4M increase over 2023 actuals, and a $1.8M increase over the average of the last rate period (2023-2027).

The increase in the 2028 Test year OM&A forecast is driven primarily by higher meter

installation volumes in the test year (377,600 meters in 2027 vs. 490,000 meters in 2028). These increased meter volumes result in corresponding growth in variable OM&A costs associated with SAAS and server hosting fees that scale as the number of meters deployed in 2028 is significantly higher than in 2027.

2.3.5 DISTRIBUTED INTELLIGENCE AND DISTRIBUTION AUTOMATION (DIDA)

2.3.5.1 PROGRAM DESCRIPTION

Distributed Intelligence and Distribution Automation (DIDA) is a core element of modernizing Hydro One's grid by enhancing visibility into the low-voltage distribution system and enabling more data-driven operations. This program supports a new investment described in DSP Section 3.11, D-SR-12 and is enabled by Hydro One's Advanced Metering Infrastructure 2.0 (AMI 2.0).

AMI 2.0 replaces Hydro One's legacy AMI 1.0 system with next-generation smart meters and communications network equipment. The enhanced computing capability, sensing functionality, data storage, and communications capabilities of AMI 2.0 enable Distributed Intelligence ("DI") applications to be deployed at the grid edge, extending the use of metering infrastructure beyond revenue metering. These capabilities improve visibility into low-voltage distribution system conditions and support more informed operational decision-making, enhanced system monitoring, and improved management of distribution system assets.

The associated capital investments have established the platforms, system integrations, and capabilities required to enable six foundational DI use cases:

- **Improved Grid Hierarchy**: Delivers locational awareness capability providing a single authoritative view of customer-to-transformer connectivity;
- **Load Visibility and Insights:** Delivers visibility of load profiles and insights from the individual service-point up through to service transformer level, replacing assumption driven loading tables and analysis with auditable, data driven visibility and analytical insights;

- **Power Quality Monitoring and Management:** Delivers DI app data (e.g., voltage monitoring) for structured remote detection and triage of power quality issues at the consumer service point level;
- **Non-Wires Solutions (NWS) Design and Integration:** Delivers analytics to help identify, design, and evaluate NWS for locations where load relief can defer or avoid traditional upgrades, using trusted connectivity and existing DI data sets (e.g., Locational awareness, Transformer Load Monitoring, Transformer Voltage monitoring, EV awareness), and outputs from other foundational use cases;
- **Distributed Energy Resource (DER) Enablement**: Provides improved visibility of loads and DERs <12kW, enabling more accurate planning of DER hosting capacity and more efficient use of existing capacity. This use case is achieved through combining data from several DI Apps (DI Load and Voltage Monitoring, Load Disaggregation, Locational Awareness), AMI 2.0-meter data, and analytics; and
- **Asset Planning Enhancement:** Operationalizes data driven planning (as opposed to planning using static or nameplate data). With automated updates in place, planners see current, measured loading and credible forward views without the need for data manipulation.

These use cases support evolving system needs, including electrification, DER integration, and non-wires solutions, by providing the data and analytics required to identify system constraints and emerging operational requirements.

This program supports the ongoing operation and sustainment of DIDA, including software licensing, platform hosting, system support and integration maintenance, development and trial of new DI applications, training and change management, and specialized operational resources.

2.3.5.2 PROGRAM EXPENDITURES

Table 27 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Distribution Intelligence and Distribution Automation (DIDA).

Table 27 - Distributed Intelligence and Distribution Automation (DIDA) ($M)

Program	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Distributed Intelligence and Distribution Automation (DIDA)	0.0	0.0	0.0	4.1	0.0	6.0

The 2028 Test year expenditure for DIDA is $6.0M, which represents the first full year of operationalization and sustainment of DIDA, based on the forecasted number of DIDA enabled devices in the service territory, as shown in Table 28 below.

Table 28 - Cumulative DIDA Enabled Meters Forecast by Year

Program	Historical	Forecast			
	2025	2026	2027	2028	2029
DIDA Enabled Meters	85,970	405,546	737,806	1,168,912	1,299,955

Once all the DIDA enabled meters are installed, the ongoing DIDA sustainment cost breakdown is summarized in Table 29.

Table 29 - DIDA Sustainment Activities

DIDA Sustainment Activity	% of Total Cost
DI Application License & Hosting Fees	41%
Sustainment of DI Platform Integration with other Hydro One systems (e.g., SAP, GIS etc.);	17%
DI QA Environment hosting cost for trialing new Applications before deploying to the production environment;	5%
The design, development, testing, go-live, and sustainment of uses cases, and training for Lines of Business end-users; and	28%
Dedicated FTE's to maintain DI Applications, and triage and resolve issues.	9%
Total	**100%**

2.4 VEGETATION MANAGEMENT

2.4.1 OVERVIEW

Hydro One's distribution system includes approximately 114,000 circuit kilometres of overhead distribution lines constructed within approximately 104,000 kilometres of designated rights-of-way ("ROWs"). Vegetation within and adjacent to these ROWs must be managed to maintain appropriate clearance from distribution infrastructure and support safe and reliable system operation.

Trees and other vegetation can contact distribution infrastructure directly or fall onto lines, particularly during adverse weather conditions. Such contacts can damage conductors, poles and other equipment, cause customer interruptions, impede access for restoration activities and create public safety risks. Vegetation management is therefore an important component of the lifecycle management of Hydro One's overhead distribution system. The associated asset condition and demographics of the ROWs is discussed in further detail in DSP Section 3.2 subsection 3.2.3.5.

Hydro One manages these risks through the following vegetation management programs:

- **Defect Correction program**: manages vegetation within and adjacent to ROWs through inspections, risk-based tree trimming and hazard tree removal (Optimal Cycle Protocol or OCP) and brush control;
- **The Public Safety & Reliability (PS&R) program**: addresses conditions that require intervention outside the planned cycle including responding to customer and internal requests, the Outliers program and ROW widening; and
- **The QA/QC program:** provides oversight, quality assurance, and continuous improvement for Hydro One's vegetation management activities.

OCP was introduced in 2018 and produced positive results. However, higher-than-anticipated defect densities during the first OCP cycle, combined with subsequent reprioritization of funding to address demand-driven work and cost pressures, reduced OCP and brush accomplishments. This increased cycle lengths, vegetation defect densities, and vegetation-related reliability risk. While Hydro One introduced interim

mitigation measures to manage the highest risks, it must now address the cumulative impacts of deferrals to appropriately manage reliability risks and future remediation costs. Hydro One's proposed OCP and enhanced brush management programs will restore sustainable cycles and ROW conditions, but appropriate levels of funding are required to achieve these results. As outlined in Table 30 below, the 2028 Test Year expenditure for Vegetation Management OM&A is $230.9M, representing an increase of $113.0M over 2023 actuals and $123.7M over the 2023-2027 average.

Table 30 - Distribution Sustainment Vegetation Management OM&A ($M)

Program	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Defect Correction (OCP) and Brush Control	104.0	102.5	73.0	80.2	82.0	208.4
Public Safety & Reliability (excluding brush control)	13.2	13.7	18.3	21.7	22.1	21.2
QA/QC	0.7	0.6	1.3	1.3	1.3	1.3
Total	**117.9**	**116.8**	**92.6**	**103.2**	**105.4**	**230.9**

2.4.2 CURRENT RATE PERIOD PROGRESS AND CHALLENGES

First Cycle of OCP

Hydro One introduced the Optimal Cycle Protocol (OCP) in 2018 as a defect-driven vegetation management approach based on a targeted three-to-five-year clearing cycle. The first cycle of OCP envisioned two complementary activities: tree trimming and hazard tree removal, and brush management. This initial cycle focused on reclaiming overgrown corridors and addressing the vegetation defects most likely to impact reliability and public safety.

The program delivered measurable benefits early on. As is displayed in Figures 89 and 90 of DSP Section 3.2, feeders treated under OCP experienced reliability improvements, while annual accomplishments increased significantly relative to historical levels. OCP also reduced average unit costs from approximately $8,102 per km during 2015-2017 to $5,135 per km during 2018-2022.

The first OCP cycle demonstrated that shorter, defect-focused proactive vegetation management cycles improve reliability, increase operational efficiency, and reduce overall lifecycle costs, while restoring corridor conditions. The proposed 2028-2032 plan builds on these demonstrated outcomes while addressing the deterioration that occurred during the current rate period.

Operational Complexities

Beginning in 2023, annual vegetation management accomplishments were lower than planned. Higher-than-anticipated defect densities during the first OCP cycle, combined with subsequent reprioritization of funding to address demand-driven work and cost pressures, reduced OCP and brush accomplishments. This increased cycle lengths, vegetation defect densities, and vegetation-related reliability risk. Combined, these factors resulted in reductions to the brush control program and OCP kms managed. Hydro One's asset condition information indicates that an increase in vegetation management is required. As detailed in DSP Section 3.2 subsection 3.2.3.5.

- OCP[3] defect density increased from approximately 21 defects per kilometre in 2021 to approximately 60 defects per kilometre in 2025, an increase of approximately 186% (see DSP Section 3.2, Figure 86).
- R0 defects increased from approximately 39% of vegetation maintenance work in 2021 to approximately 58% in 2025 (see DSP Section 3.2, Figure 87).
- The number of ROW kilometres completed declined from approximately 14,296 kilometres in 2023 to 12,340 kilometres in 2024 and 7,623 kilometres in 2025 (see DSP Section 3.2, Figure 89) and over 2023 to 2027, the average vegetation management cycle is forecast to increase to 10.8 years (see DSP Section 3.2, Figure 88).

[3] Optimal Cycle Protocol (OCP) was adopted by Hydro One in 2018 as a means of reducing cycle times without increasing the overall cost of the vegetation management program.

Performance Trends

Vegetation-related reliability performance has deteriorated over the 2023 to 2025 period. The trend is consistent with the observed increase in vegetation defect density, longer vegetation-management cycles, and increasing adverse weather. Excluding Major Event Days (MED) as defined by IEEE 1366 2.5Beta methodology:

- tree-caused SAIDI increased from approximately 2.34 hours in 2023 to 3.36 hours in 2025;
- tree-caused SAIFI increased from approximately 0.52 interruptions in 2023 to 0.72 interruptions in 2025;
- tree-caused outages increased from approximately 7,894 in 2023 to 10,782 in 2025; and
- tree-caused customer outage hours increased from approximately 3.4 million hours in 2023 to approximately 5.1 million hours in 2025.

Many corridors have gone eight years without brush management, resulting in higher defect densities and more time-intensive vegetation treatment requiring specialized forestry resources. As a result, accomplishments are lower than forecast and unit costs have increased from $6,946 per km in 2023 to $8,457 per km in 2025 (see Figure 5).

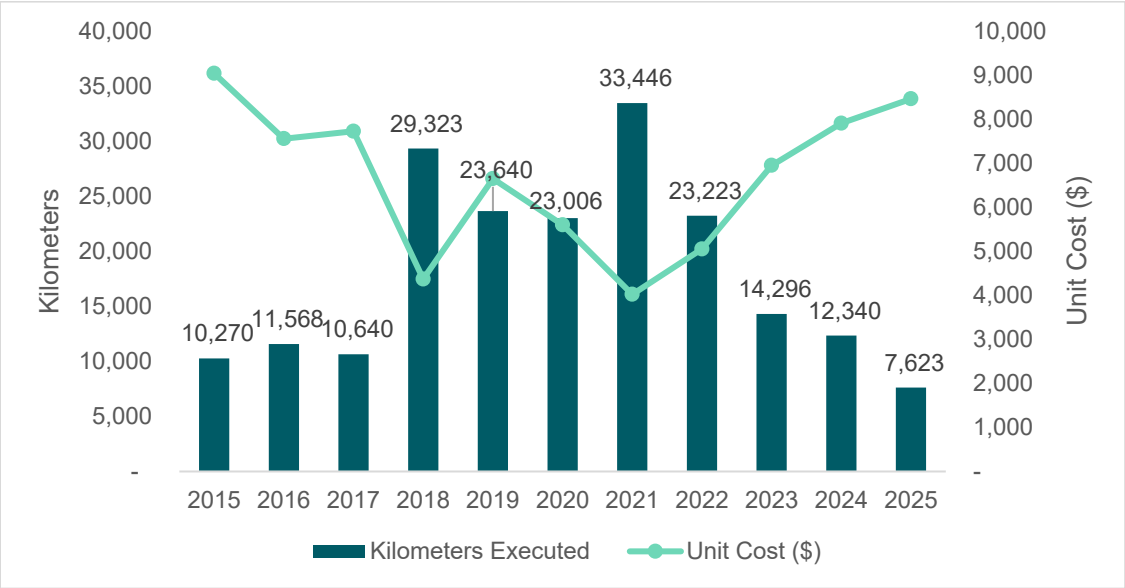

Figure 5: OCP Kilometers Executed and Unit Cost

Notwithstanding this, Hydro One's unit costs are generally consistent with North American utility benchmarks, as demonstrated in the CNUC 2026 Hydro One Vegetation Management Study (see DSP Section 3.3, Attachment 1).

Deferred vegetation management work has affected customer reliability and outage restoration. The Valora DS F1 feeder was among the worst-performing feeders in 2022 and 2023, with vegetation conditions contributing to its high SAIDI. In Vittoria and Straffordville, tree-related outages led to poor SAIDI and SAIFI performance and customer complaints. Dense brush has also delayed restoration at off-road locations by preventing line crews from accessing equipment and restringing damaged conductors. For example, forestry crews had to clear more than 20 spans on Knox Point Road before power could be restored in 2025.

Mitigation Measures

To address the impacts of the operational complexities described above, Hydro One proactively identified and managed the safety and reliability risks associated with deferred vegetation work through the following targeted measures:

- refining the Optimal Cycle Protocol scope in 2024 to prioritize critical and higher-risk defects;
- implementing the Outliers initiative in 2024 to remove high-risk trees in areas most frequently affected by severe weather;
- increasing brush control funding in 2026 and 2027 for feeders experiencing the highest number of vegetation-related outages; and
- completing vegetation work in support of the Broadband program.

The revised Optimal Cycle Protocol scope directed available resources to vegetation conditions presenting the greatest safety and reliability risks. This is described in greater detail in section 2.4.1.2 below.

The Outliers initiative used tree-caused outage data at the protection-device level to identify off-cycle areas with high reliability impacts. On treated feeder sections longer than

two kilometers, interruption frequency improved by 54% on normal weather days, 36% on storm days and 57% during Force Majeure events relative to pre-treatment performance.

Hydro One increased brush control funding for 2026 and 2027 for feeders with the highest number of vegetation-related outages. This work addresses priority corridor-floor vegetation that could interfere with line access, operations and outage restoration.

Vegetation work completed through the Broadband program also improved corridor conditions. Approximately 2,000 kms of Optimal Cycle Protocol line clearing and 32 hectares of brush removal are expected to be completed over the life of the program. This work provides localized benefits but generally covers feeder segments rather than full feeder treatments.

Together, these measures allowed Hydro One to proactively identify and address the highest-priority vegetation risks within available funding, and to offset and manage the reliability consequences of increasing adverse weather and reduced accomplishments. However, these mitigation measures are only short-term solutions. Significant investment is required to restore ROW conditions through appropriately paced maintenance cycles.

2.4.3 2028-2032 VEGETATION MANAGEMENT

Hydro One uses an integrated, cyclical and risk-informed vegetation management strategy that focuses on recurring inspection and vegetation treatment to maintain appropriate clearances from energized infrastructure, control vegetation growth, address hazard trees, preserve access to distribution facilities, and manage vegetation-related reliability and public safety risk.

ROW conditions change continuously as vegetation grows and as trees within and adjacent to the ROW are affected by maturity, disease, pests, weather and other environmental conditions. The timing and extent of vegetation management are therefore important lifecycle considerations. As the period between interventions increases,

vegetation density and defect levels can increase, and the amount and complexity of work required during the subsequent intervention can also increase.

Hydro One's 2028-2032 strategy is therefore designed to restore sustainable maintenance cycles, address accumulated vegetation growth, improve ROW accessibility, and reduce safety, reliability, and operational risks across the distribution system. The strategy will be executed through the following vegetation management programs:

- **Defect Correction program** consists of OCP/OCP Flex vegetation treatment and brush management;
- **PS&R program** involves responding to customer and internal requests, ROW widening, ROW floor clearing, the Outliers Program etc.; and
- **The QA/QC program** includes oversight, quality assurance, and continuous improvement programs for Hydro One's vegetation management activities.

2.4.4 DEFECT CORRECTION

2.4.4.1 PROGRAM DESCRIPTION

OCP Program

OCP is Hydro One's management framework for maintaining distribution ROWs through cyclical, risk-based tree trimming and hazard tree removal. The program was implemented to proactively manage vegetation-related reliability and safety risks by targeting the most critical defects and maintaining feeders on an optimal maintenance cycle. Hydro One introduced the OCP in 2018, transitioning from a predominantly corridor-clearing approach to a defect-driven approach focused on identifying and treating vegetation that could affect distribution infrastructure. OCP improved the targeting of vegetation management work and contributed to improvements in vegetation-related reliability and vegetation management unit costs.

Vegetation conditions and risk vary materially across Hydro One's service territory. Vegetation growth, accessibility, reliability consequences, weather exposure and other local conditions can differ significantly between and within feeders. Accordingly, applying

relatively standardized work prescriptions at the feeder level does not fully reflect the conditions and risks present at individual ROW sections.

Hydro One is transitioning OCP to an enhanced approach referred to as OCP Flex. OCP Flex retains the cyclical and defect-management principles of OCP while introducing a more granular, condition- and risk-informed approach to determining where and to what extent vegetation management work is required using improved data, analytics, and remote sensing technologies to identify and prioritize work at the span[4]-level.

For ROW sections selected for treatment, OCP Flex will use two components of work prescription. Base prescriptions will address vegetation required to maintain appropriate reliability and public safety conditions. Flexible prescriptions will allow additional vegetation to be addressed where warranted to proactively manage future defects, taking into account local conditions, anticipated return-to-site intervals and other relevant constraints. This provides Hydro One with the ability to vary the intensity of vegetation treatment rather than applying a uniform prescription across the distribution system.

OCP Flex is being introduced during 2026-2027 (Phase 1), with full deployment planned for 2028 (Phase 2). This phased implementation provides an opportunity to incorporate operating experience and refine vegetation data, work prescriptions and planning processes prior to full-scale implementation during 2028-2032.

Brush Management Program

The Brush Control program manages woody vegetation on the ROW floor through mechanical and manual clearing and, where appropriate and permitted, targeted herbicide application. The program also includes brush within proximity that requires qualified resources because of its location near energized conductors. Proactive brush control supports corridor access, limits regrowth, and reduces the progression of small vegetation into larger or line-proximity defects requiring more specialized forestry work.

[4] One span is equivalent to the distance between one pole and the subsequent pole.

Hydro One's ability to complete planned brush management was constrained during prior vegetation management cycles. During the first OCP cycle, higher than anticipated vegetation defect densities required resources planned for brush management to be redirected to tree trimming and removals. Together with subsequent reprioritization of planned work, these factors delayed brush control and contributed to increasing vegetation defect densities. It also prevented the application of herbicide following brush control, allowing vegetation to regrow more rapidly.

In alignment with the CNUC Benchmarking Survey recommendation, Hydro One is increasing the role of proactive brush management during the 2028–2032 period. The enhanced approach is intended to address brush earlier in its growth cycle and reduce the rate at which lower-growing vegetation develops into larger or line-proximity defects requiring more specialized forestry resources.

Brush treatment will include mechanical and manual clearing and, where permitted and appropriate, the targeted and controlled application of herbicides following clearing to limit regrowth and extend the effectiveness of the initial treatment. Compatible low-growing vegetation may also be established where appropriate to limit future woody vegetation growth. This approach recognizes that clearing vegetation without effectively managing regrowth can result in the ROW returning more quickly to an overgrown condition. The targeted use of herbicides is therefore an important element of the 2028–2032 brush management strategy and is responsive to the 2026 CNUC Benchmarking Study which identified that Hydro One's use of herbicides is well-behind that of peer respondents.

Hydro One will use a risk-based approach to prioritize brush-management locations. Factors considered may include accessibility, vegetation characteristics, outage and restoration history, span characteristics and local forestry knowledge. This represents a shift toward recognizing proactive brush management as an integral component of maintaining ROW condition over the long term.

Figures 6 through 9, below, include examples of current ROW conditions with overgrown brush. Under current funding, cycle lengths are projected to increase, and unit costs are expected to continue their upward trend. Figure 10 demonstrates how a corridor looks following mechanical and manual brush clearing followed by herbicide application.

Figure 6: Overgrown Brush

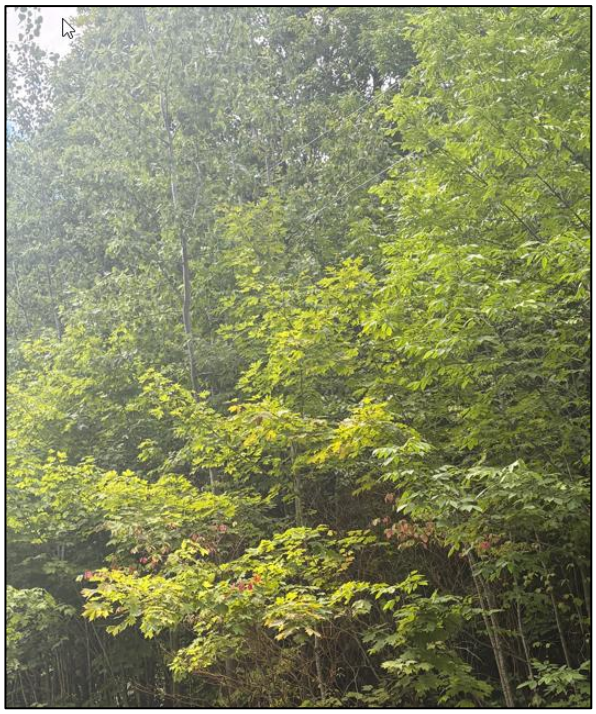

Figure 7: Overgrown Brush

Figure 8: Overgrown Brush

Figure 9: Overgrown Brush

Figure 10: Example of ROW after receiving herbicide brush treatment

Expected Outcomes

Cycle length remains an important element of the lifecycle strategy. Hydro One's long-term objective is to achieve an average return-to-site cycle of approximately five years.

Although the average system-wide cycle over the 2028-2032 period is forecast to be 6.6 years, Hydro One expects approximately 76% of ROW to meet the five-year target by the end of 2032 as higher-risk corridors are prioritized first. The five-year cycle is supported by the 2017 Forestry Assessment, the 2021 OCP First Cycle Performance Study, and the 2026 CNUC Benchmarking Study (DSP Section 3.3, Attachment 1). Accelerating achievement of the five-year cycle during the 2028-2032 planning period would require approximately 31% higher expenditures. Recognizing the affordability implications of restoring the five-year clearing cycle, Hydro One's proposed pace balances near-term customer impacts with the need to reduce the accumulated backlog and move the program toward a sustainable cycle.

Investment in both OCP Flex and the enhanced Brush Control program is necessary to achieve targets, as the two programs work together to address the highest-risk vegetation conditions, balance affordability and execution realities, and deliver long-term value for customers through a safer and more reliable distribution system.

Performance will be assessed on the combined cost of managing the right-of-way rather than either program individually. Figure 11 displays the combined unit cost for OCP and Brush from 2023 to 2032 in comparison to the 2026 CNUC Benchmarking Study findings (data from 2024). In comparison to other utilities, Hydro One's cost per unit is less than peers.

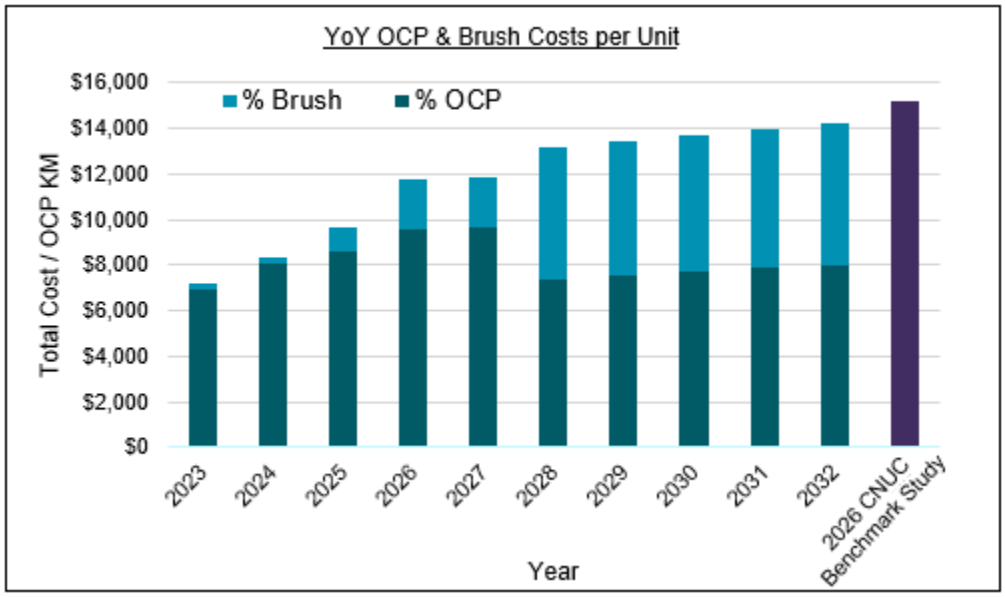

Figure 11: Year-Over-Year OCP and Brush Control Cost per Unit

2.4.4.2 PROGRAM EXPENDITURES

Table 31 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Vegetation Management Defect Correction OM&A.

Table 31 - Vegetation Management OM&A ($M) - Defect Correction

Defect Correction Sub-Programs	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
OCP	$99.6	$98.3	$64.9	$65.2	$67.0	$117.5
Brush	$4.4	$4.2	$8.1	$15.0	$15.0	$90.9
Total	**$104.0**	**$102.5**	**$73.0**	**$80.2**	**$82.0**	**$208.4**

The 2028 Test year expenditure for Defect Correction is $208.4M, representing a $104.4M increase from 2023 actuals, and a $120.1M increase above the average of the last rate period (2023-2027). The increase reflects the work required to restore ROW conditions, address deferred brush control activities, and progress toward sustainable vegetation management cycles. The forecast was developed based on historical unit costs and incorporates delivery efficiencies associated with digital customer notification processes, enhanced planning tools, and a diversified resource mix.

The 2028 Test year expenditure for OCP is $117.5M, representing a $17.9M increase from 2023 actuals, and a $38.5M increase above the average of the last rate period (2023-2027). The Test year forecast assumes that 15,833 kms of line clearing will be completed and will position Hydro One to an average return-to-site cycle of approximately 6.6 years and restore 76% of its distribution right-of-way to standard by the end of 2032. The 2028 OCP unit cost is forecast at $7,401 per km, below the 2025 actual cost of $8,457 per km. This reduction reflects planned delivery efficiencies and the transfer of work to the dedicated Brush Control program as described in DSP Section 3.2, Subsection 3.2.3.5.3.1.2.

The Test year expenditure for Brush Control is $90.9M, representing an $86.5M increase from 2023 actuals, and an $81.6M increase above the average of the last rate period (2023-2027). The Test year forecast increases from $15.0M in 2027 to $90.9M in 2028 to

address accumulated brush growth and restore sustainable ROW conditions. The 2028 plan includes 31,200 hectares of backlogged brush activity, with about 30% requiring topping. The forecast also reflects the transfer of brush-within-proximity activities from OCP to Brush Control beginning in 2028. Because a portion of the increase reflects a change in program classification rather than incremental work scope, OCP and Brush Control expenditures will be assessed collectively when evaluating the overall cost of vegetation management.

The unit costs for the OCP and Brush Programs are presented in Figure 11. The combined OCP and Brush unit cost is in line with peer utilities. The CNUC 2026 Benchmarking Study indicates that Canadian peers were spending $15,232/km in 2024 compared to Hydro One's $13,042/ ROW km managed in 2028. Hydro One's lower unit cost reflects a deliberate approach to balance affordability and resource capacity.

2.4.5 PUBLIC SAFETY AND RELIABILITY (PS&R)

2.4.5.1 PROGRAM DESCRIPTION

The Public Safety & Reliability (PS&R) programs address vegetation-related conditions that require intervention outside the planned vegetation management cycle. Activities may include responding to customer and internal requests, ROW widening, ROW floor clearing, and other vegetation management treatments outside of OCP. The program consists of Demand and Planned work, which mitigates localized safety and reliability risks identified through customer requests, off-cycle inspections, historical performance, field observations, and other operational intelligence.

Programs such as Outliers, Customer Requests, and Off-Cycle Requests provide targeted interventions where vegetation conditions create elevated reliability or safety concerns that cannot be addressed through the normal vegetation management cycle. These programs complement, but do not replace, Hydro One's broader lifecycle approach to vegetation management.

Demand Driven PS&R Program

Demand driven PS&R work primarily consists of responding to customer requests (CRs) and internal requests (Off-Cycle Requests, or OCRs) related to vegetation management in proximity to Hydro One's energized assets and that require intervention. During the current rate period, greater defect densities resulted in a greater number of defects being addressed through the Off-Cycle Request ("OCR") program.

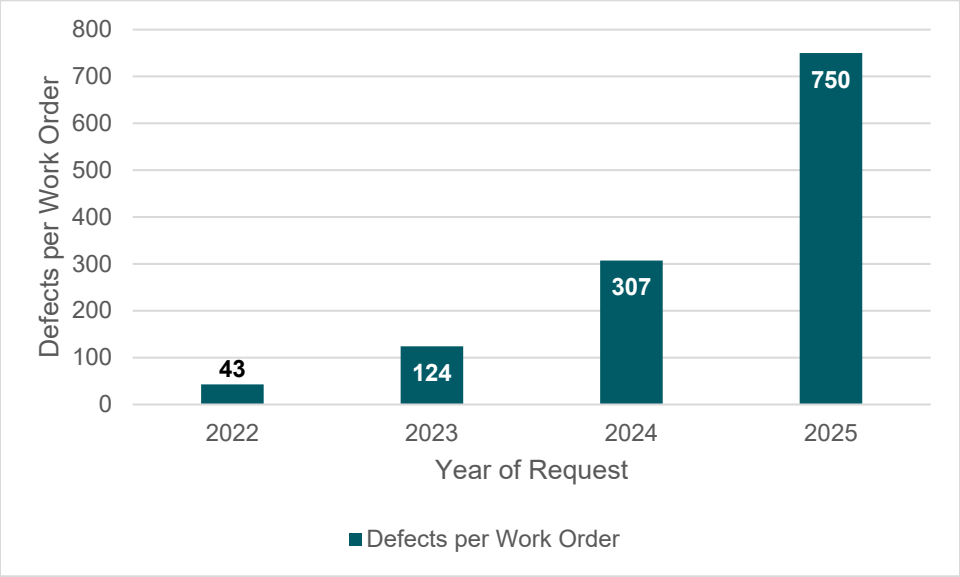

Figure 12: Defects per Off-Cycle Request (2022-2025)

Planned PS&R program

The Planned PS&R program enables off-cycle investments in Hydro One's ROWs to improve system reliability and address potential safety risks. The Outliers Program was introduced as part of planned work to proactively remove high-risk trees in areas most frequently impacted by severe weather.

OCP provides a system-wide framework for managing vegetation, while the Outliers Program identifies that certain locations are subject to local characteristics that result in materially different vegetation-related risks including exposure to prevailing wind corridors,

proximity to lakes, local forest conditions, storm exposure and other site-specific ecological factors.

Under the Outliers Program, Hydro One identifies distribution sections with elevated vegetation-related outage frequency and consequences. Specialized forestry personnel then use local knowledge and field assessments to identify additional vegetation treatment that may be warranted beyond the work prescribed through the cyclical program. Work is coordinated with OCP/OCP Flex schedules to avoid unnecessary duplication. Early program experience witnessed reductions in interruptions on treated sections during both blue-sky and storm days.

Brush Control activities also formed part of the Planned PS&R program during the 2023-2027 period. Beginning in 2028, these activities will transition to the OCP Flex framework, where brush requirements will be identified and prioritized using the same risk-based approach applied to other planned vegetation work. Brush condition data will also be collected concurrently with tree trimming and hazard tree assessments, creating a more integrated and efficient approach to planning and managing right-of-way vegetation.

2.4.5.2 PROGRAM EXPENDITURES

Table 32 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Vegetation Management, Public Safety & Reliability OM&A.

Table 32 - Distribution Sustainment Vegetation Management OM&A - Public Safety & Reliability Spend Breakdown ($M)

Program	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
CR & OCR Programs (Demand driven)	$13.0	$11.5	$12.7	$15.8	$16.1	$18.2
Outliers	$0.0	$1.2	$1.4	$1.4	$1.4	$1.4
DSC Safety Patrol	$0.2	$1.0	$4.2	$4.5	$4.6	$1.6
Total Actual Spend	**$13.2**	**$13.7**	**$18.3**	**$21.7**	**$22.1**	**$21.2**

The 2028 Test year PS&R expenditure is $21.2M, representing an increase of $8.0M over 2023 actuals and $3.4M above the average expenditure during the current rate period (2023-2027). The forecast reflects the higher number of defects identified through off-cycle requests, together with continued targeted mitigation through the Outliers Program.

The 2028 plan includes $18.2M for Customer Request (CR) and Off-Cycle Request (OCR) programs, $1.4M for Outliers, and $1.6M for DSC Safety Patrols. CR and OCR programs assume continued heightened defect densities into 2028 and remain steady from 2028 – 2032 as Hydro One expands its OCP and Brush Control program.

The 2028 Distribution System Code (DSC) Safety Patrol expenditure of $1.6M in 2028 reflects patrols that are required to maintain compliance with the Distribution System Code. The work in this program remains executed by Forestry Technicians. Beginning in 2028, ongoing Distribution Line Patrols will be managed under Lines Maintenance. As Lines Maintenance progressively increases their capacity to execute more, high-grade detailed pole inspections, and the need for just-in-time inspections to ensure compliance with minimum regulatory requirements will reduce. Accordingly, the vegetation management expenditure is transitional and does not duplicate the patrol activities funded through Lines Maintenance.

Also, as observed in Table 32, DSC patrol expenditures increased from 2023 to 2025 due to longer cycle lengths. As vegetation management cycle lengths increased, separate patrol activities became necessary to maintain inspection compliance, resulting in the establishment of the DSC Safety Patrol program.

2.4.6 QUALITY ASSURANCE (QA) AND QUALITY CONTROL (QC) PROGRAM

2.4.6.1 PROGRAM DESCRIPTION

The QA/QC program provides oversight, quality assurance, and continuous improvement for Hydro One's vegetation management activities. Assessments completed under this program are the primary mechanism through which Hydro One evaluates adherence to its vegetation management defect specifications and assesses the long-term effectiveness

of program investments. The program consists of two components - work quality assessments and innovation and program development initiatives.

As Hydro One transitions to OCP Flex, independent quality assessments, data validation, and program oversight will help ensure vegetation management activities are executed consistently, aligned with program specifications, and achieve the intended safety and reliability outcomes. These activities also support the continuous refinement of work practices, planning assumptions, and risk-based prioritization processes.

Work Quality Assessments

Annual third-party assessments are conducted to verify the accuracy of vegetation inspections and compliance with vegetation management specifications, clearance standards, and work quality requirements. Auditors independently assess feeder segments and compare identified defects and completed treatments against Hydro One's standards to identify discrepancies, determine root causes, support corrective actions, improve training and drive continuous improvement. In 2024, assessments covered 200km of inspected feeders and 470km of completed work, with results demonstrating strong compliance with OCP specifications and vegetation clearance standards, averaging 0.85 findings per km for inspections, and 0.40 findings per km for completed work.

Innovation and program development initiatives

Innovation and program development activities evaluate emerging technologies and practices that may improve the effectiveness, efficiency, and data quality of Hydro One's vegetation management programs. Recent initiatives have included pilots and assessments of remote sensing technologies, including satellite imagery, aerial-based LiDAR, drone inspections, mobile mapping and computer vision, as well as cloud-based vegetation management platforms. The learnings from these initiatives will inform the implementation and ongoing development of the Intelligent Grid Platform's Vegetation Management Module, discussed in ISD-SS-09, to enhance vegetation condition data and provide a more comprehensive view of vegetation risk across the distribution system. This

improved visibility will support more informed decisions about where, when, and how vegetation management resources are deployed, helping to reduce vegetation-related risk to ALARP (As Low As Reasonably Possible) and improve reliability and customer outcomes.

Hydro One also participates in industry research and benchmarking organizations, and utility vegetation management forums, including EPRI and CEATI, to evaluate emerging practices and incorporate lessons learned into its programs, as further described in Exhibit E-03-03. These activities support the ongoing evolution of Hydro One's risk-based vegetation management approach and help identify opportunities to improve the management of vegetation along distribution ROWs. As Hydro One expands its risk-driven approach beginning in 2028, the insights gained through these initiatives will support the identification of locations requiring specialized vegetation management activities, such as pest and disease surge control, storm preparation, post-storm weakness identification, post-storm clean-up, and wildfire prevention or post-wildfire restoration. Over time, these learnings will help establish standardized data collection processes, work practices, and corrective actions that can be integrated into vegetation management programs to further improve the effectiveness and consistency of vegetation management across Hydro One's rights-of-way.

2.4.6.2 PROGRAM EXPENDITURES

Table 33 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for the Vegetation Management, QA/QC program.

Table 33 - Vegetation Management - QA/QC ($M)

	Historical				Bridge Year	Test Year
Program	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
QA/QC	0.7	0.6	1.3	1.3	1.3	1.3

The 2028 Test year expenditure of $1.3M represents an increase of $0.6M relative to 2023 actuals and $0.3M above the average annual expenditure over the 2023-2027 period, which is consistent with 2025 actual and the 2026 and 2027 forecasts. The QA/QC expenditure forecast reflects the resources required to provide ongoing oversight of the vegetation management program, validate the accuracy of field and remote-sensing information, and support continuous enhancement of planning and execution processes. Expenditures increased beginning in 2025 with the introduction of remote-sensing quality control activities associated with LiDAR and satellite-based vegetation assessments. This level of expenditure is forecast to continue through the bridge and test years to support data-driven vegetation management practices, program governance, and continuous improvement initiatives.

2.4.7 EXPECTED OUTCOMES

The proposed Vegetation Management OM&A plan responds to a clear lifecycle requirement to maintain the safety, reliability and accessibility of Hydro One’s distribution rights-of-way.

OCP Flex, including enhanced brush management, targeted PS&R programs, and continuous improvement activities are expected to mitigate public safety risks related to tree contacts and wildfires, restore sustainable vegetation management cycles, improve ROW accessibility, reduce vegetation defect growth, and support improved reliability performance.

The proposed expenditures represent a prudent and cost-effective lifecycle investment that restores sustainable vegetation management cycles, mitigates growing safety and reliability risks, and avoids higher future costs that would result from continued deterioration of Hydro One's distribution rights-of-way.

2.5 SMART GRID INVESTMENTS

Hydro One’s Smart Grid Investments OM&A programs are designed to support the transition to a more flexible, intelligent, and distributed electricity system. The portfolio is

centered around three key program areas: Non-Wires Solutions (NWS), Battery Energy Storage Systems (BESS), and Smart Devices & DER Support. The NWS programs focus on identifying and deploying alternatives to traditional wires-based infrastructure through advanced planning studies, analytics, demand response initiatives, local energy efficiency programs, and Distributed Energy Resource Management Systems (DERMS). These investments enable Hydro One to leverage customer-owned and utility-owned distributed energy resources, such as smart thermostats, electric vehicle chargers, and battery storage, to address system constraints and reduce peak demand. The BESS program supports the ongoing operation, monitoring, and maintenance of both grid-scale and residential battery systems, ensuring these assets continue to provide reliability, resiliency, and operational benefits throughout their lifecycle.

The overall benefit of these programs is the creation of a more resilient, efficient, and customer-focused distribution system. By expanding the use of distributed energy resources, advanced grid management platforms, smart devices, and energy storage technologies, Hydro One can improve reliability, enhance outage response, increase operational flexibility, and defer or potentially avoid traditional infrastructure investments. Investments in DERMS, ADMS, communications infrastructure, and DER testing capabilities also provide the foundational technology required to integrate emerging energy resources safely and effectively. Collectively, these programs support grid modernization, improve Hydro One's ability to manage increasing electrification and customer participation, and position the utility to meet future energy needs at a lower overall cost while maintaining system reliability and resilience.

Table 34 below provides an annual breakdown of the programs within Hydro One's Smart Grid OM&A expenditures. Sections 2.5.1 to 2.5.3 provide more detailed descriptions of the work and expenditures in each program.

Table 34 - Summary of Smart Grid Investments OM&A ($M)

Smart Grid Investments OM&A	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Non-Wires Solutions	0.0	0.0	1.2	4.3	4.0	5.4
Battery Energy Storage Systems	0.0	0.0	0.3	1.1	1.3	3.0
Smart Device & DER Support	0.3	1.0	1.3	2.2	3.0	2.6
Total	**0.3**	**1.0**	**2.8**	**7.5**	**8.2**	**11.0**

The 2028 Test year expenditure for Smart Grid Investments OM&A is $11.0M, a $10.7M increase over 2023 actuals, and a $7.1M increase over the average of the last rate period (2023-2027). The increase is primarily attributable to investments in Non-Wires Solutions and Battery Energy Storage System programs, which are discussed below in sections 2.5.1 and 2.5.2, respectively.

2.5.1 NON-WIRES SOLUTIONS

2.5.1.1 PROGRAM DESCRIPTION

Hydro One has established two NWS programs that support the analysis and deployment of Non-Wires Solutions:

- **NWS System Planning & Analytics:** This program is focused on studies and analytics that support the identification of NWS opportunities. As detailed in DSP Section 3.6, Attachment 1, Hydro One performs its own screening of capital investments to determine which investments could potentially be addressed by an NWS. Following this initial assessment, a subsequent analysis is performed by a third party, using proprietary tools and industry experience, to determine the achievable potential of an NWS within a defined area. These third-party studies support decisions on whether to proceed with an NWS in place of a capital (wires) alternative.
- **NWS Operationalization**: This program focuses on operationalizing NWS by providing the tools and resources required to reduce system loading at peak times, to address a system need.

With respect to tools, the program includes costs related to software platforms that forecast peak events, and in response to peak events, coordinate the dispatch of distributed resources at a specific location, time, and duration. The primary software platform that underpins this coordinated dispatch is a Distributed Energy Resource Management System (DERMS), which is essential to effectively manage and scale a diverse set of DERs in support of NWS.

During the current rate period, DERMS is being implemented as a fully cloud-based standalone solution, with associated expenditures funded through the NWS Operationalization program. This approach will allow Hydro One to continue expanding its NWS capabilities while an on-premises DERMS solution is under development. Once the on-premises solution is deployed, these DERMS expenditures will transition out of the NWS Operationalization program. This transition is expected to occur in 2028.

With respect to resources, the NWS Operationalization program includes payments for end-use resources such as Mobile Battery Energy Storage Systems (MBESS), as well as incentive payments for residential dispatchable resources such as smart thermostats, and various C&I flexible resources. Hydro One was also successful in securing funding from NRCan to offset a portion of the program's costs, including DERMS Software as a Service (SaaS) fees and Original Equipment Manufacturer (OEM) device fees, thereby reducing the overall cost of building and operationalizing a residential Demand Response (DR) program. Anticipated NRCan contributions related to the NWS Operationalization program are detailed in Table 35 below.

2.5.1.2 PROGRAM EXPENDITURES

Table 35 below outlines 2023-2026 actuals/forecast year, 2027 bridge year, and 2028 test year expenditures for the Non-Wires Solutions component of the Smart Grid Investments OM&A program.

Table 35 - Summary of Non-Wires Solutions OM&A ($M)

Non-Wires Solutions OM&A	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
NWS System Planning & Analytics (Net)	**0.0**	**0.0**	**0.5**	**0.3**	**0.3**	**1.5**
NWS Operationalization (Gross)	0.0	0.0	0.7	5.8	5.0	4.9
Less NRCan Contribution	0.0	0.0	0.0	1.8	1.3	1.0
NWS Operationalization (Net)	**0.0**	**0.0**	**0.7**	**4.0**	**3.7**	**3.9**
Total NWS (Net)	**0.0**	**0.0**	**1.2**	**4.3**	**4.0**	**5.4**

The 2028 Test year expenditure for Non-Wires Solutions is $5.4M, a $5.4M increase over 2023 actuals, and a $3.5M increase over the average of the last rate period (2023-2027).

As can be seen from the table above, there are offsetting payments anticipated to be received from NRCan as part of Hydro One's successful application to deploy and grow a residential DR program for the benefit of the distribution system. Within the NWS Operationalization program, these offsetting payments are primarily applicable towards DERMS SaaS fees, averaging $1.2M per year (2026-2028), to maintain a platform for continued DER dispatch in support of NWS, and towards OEM and program management payments, averaging $1.1M per year (2026-2028), with an anticipated recovery amount of 50% towards both. Below is a description of the respective variances from 2025 Actual through to the 2028 Test year.

NWS System Planning & Analytics

For the NWS System Planning & Analytics program, annual expenditures are forecast to increase by $1.0M between 2025 actuals and the 2028 Test year. In 2025, 15 NWS studies were completed. 8 studies were completed in 2026, with an additional 8 studies forecast for completion. Study volume is not the sole driver of program costs. In both 2025 and 2026, the program also included investments to enhance and customize Hydro One's NWS modelling capabilities to address evolving planning needs. These investments included the quantification of peak demand reduction benefits associated with eDSM

activities and expanded model functionality to support Energy System Tests (ESTs) within the OEB's NWS Benefit-Cost Analysis framework.

The proposed increase in expenditures in the 2028 Test year is primarily driven by the introduction of third-party load disaggregation services. The insights gained through load disaggregation will improve Hydro One's understanding of residential electrification trends and end-use consumption patterns, supporting both system planning and NWS program design. For example, identifying electric vehicle charging as a contributor to overloaded service transformers would enable proactive mitigation before equipment performance issues or premature failures occur. Similarly, understanding the extent to which residential HVAC loads contribute to localized peak demand could improve customer targeting for Hydro One's thermostat demand response program, inform the design of future Stream 2 eDSM initiatives, and facilitate participation in existing IESO HVAC-related programs.

NWS Operationalization

For NWS Operationalization, annual net expenditures are forecast to increase by $3.2M between 2025 actuals and the 2028 Test year as the program matures and expands. In 2025, expenditures were primarily attributable to: (i) MBESS payments to a third party providing non-wires services; and (ii) incentive payments to Commercial and Industrial ("C&I") customers for reducing electricity consumption in localized areas during periods of peak system demand. These expenditures are expected to remain relatively consistent in 2026. The increase from 2025 to the 2028 Test year primarily reflects the following:

- **DERMS platform implementation:** The costs included in this program relate to a cloud-based DERMS solution, a portion of which is expected to transition to an on-premises solution, as described above in Section 2.5.1.1. Program costs are largely comprised of Software-as-a-Service (SaaS) fees associated with operating a DERMS, for a total of approximately $0.8M in 2028.
- **Acquisition of residential DERs:** Investments in the acquisition of distributed residential resources to support both specific NWS and broader demand response initiatives. These acquisition costs are forecast to be $0.7M in 2026 and will support approximately 6,000 new resource enrollments, including smart

thermostats, residential BESS, EVs and EV chargers. Enrollment levels are expected to remain consistent in 2027, before increasing in 2028 (as shown in Table 36 below) to support continued growth of dispatchable distributed resources that can be used either as an NWS to address specific system needs, or as a broader demand response program that provides operational capability and flexibility. The increased enrollments in 2028, at a forecast total cost of $1.5M, includes the introduction of a new Behavioural Demand Response (BDR) program that would incentivize customers to take specific demand response actions during peak periods through SMS and email notifications, rather than utility-driven direct load control (DLC).

- **DR Program Operating Costs:** Operating expenditures associated with the residential DR program, including OEM fees for the use of Application Programming Interfaces (APIs) to communicate directly with enrolled devices. These costs will total $1.1M in 2026, supporting approximately 30MW of demand response capacity, and are expected to increase to $1.2M in 2028, as capacity grows to 40MW. Historical and forecast annual device enrollments are shown in Table 36 below.

Table 36 - DR Program Device Enrollments

Device Type	Annual Enrollments					
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
HVAC Smart Thermostat	14,948	15,051	3,159	5,000	5,000	8,000
Baseboard Smart Thermostat	279	639	301	300	300	300
EV / EVSE	586	323	33	50	50	50
Powerwall	0	0	40	610	200	200
Behavioral Demand Response	0	0	0	0	0	8,000
Total	**15,813**	**16,013**	**3,533**	**5,960**	**5,550**	**16,550**

2.5.2 BATTERY ENERGY STORAGE SYSTEMS (BESS)

2.5.2.1 PROGRAM DESCRIPTION

This program primarily comprises sustainment expenses associated with the operation and maintenance of Grid Scale and Residential BESS deployed under the Energy Storage Solutions investment, DSP Section 3.11, D-SS-04. These expenditures secure preventative and corrective maintenance services as well as performance monitoring and warranties for both grid-scales and residential batteries. These expenditures are required to ensure safe and reliable operation of the assets and to sustain the benefits expected from the investment.

Grid-scale BESS

Grid-scale BESS consists of multiple components and subsystems that require ongoing performance monitoring, alarm management, preventative maintenance, and corrective maintenance to ensure reliable operation and optimal performance. Accordingly, each system is supported by a Long-Term Service Agreement ("LTSA") with a third-party vendor that provides the maintenance services required throughout the asset's life cycle. OM&A expenditure for the grid-scale BESS program is therefore primarily attributable to LTSA contract fees. These expenditures reflect both existing in-service assets and additional assets expected to enter service during the 2028-2032 period. As each new grid-scale BESS requires an LTSA, OM&A expenditures increase as additional assets are placed in service.

Residential BESS

Residential BESS comprises of units installed behind the meter for eligible residential customers. Their effective operation depends on ongoing monitoring, maintenance, and operational oversight. To support these activities, Hydro One has engaged a third-party vendor through a Support and Services Agreement. The vendor is responsible for monitoring individual systems and the aggregated fleet, identifying abnormal operating conditions, coordinating corrective actions, providing customer support, conducting remote diagnostics, and arranging field service activities where required. The agreement also includes operational reporting, performance data provision, monitoring platform

updates, and training to support Hydro One's ongoing management of the fleet. These services help ensure the availability of backup power for participating customers while maintaining the fleet's readiness to support system reliability needs.

2.5.2.2 PROGRAM EXPENDITURES

Table 37 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for the BESS component of the Smart Grid Investments OM&A program.

Table 37 - Summary of Smart Grid Investments OM&A ($M) - BESS

BESS Program	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Grid Scale BESS	0.0	0.0	0.0	0.3	0.5	0.5
Residential BESS	0.0	0.0	0.3	0.8	0.8	2.5
Total	**0.0**	**0.0**	**0.3**	**1.1**	**1.3**	**3.0**

Grid-scale BESS

Grid-scale BESS OM&A expenditures are forecast based on the first-year service fees specified in the most recent Long-Term Service Agreement ("LTSA"), escalated annually to reflect inflation and other economic factors. The resulting amount represents the annual OM&A cost per asset. Total annual OM&A expenditures are calculated by applying the escalated LTSA cost to the cumulative number of grid-scale BESS assets expected to be in service in each year. The forecast is based on the payment schedule in the most recent LTSA for a BESS project, which includes a first-year fee and an annual escalation factor of 2.5%. Based on this methodology, grid-scale BESS OM&A expenditures are forecast at approximately $0.5M in the 2028 Test year and are expected to increase to $7.4M by the end of the rate period as additional grid-scale battery systems are deployed under the proposed Energy Storage Solutions investment, DSP Section 3.11, D-SS-04.

Residential BESS

The Residential BESS OM&A expenditures are based on the annual OM&A cost per residential BESS under the vendor Support and Services Agreement. This agreement

covers costs to monitor, maintain, and support the safe and reliable operation of the residential BESS fleet. This cost is used along with the existing population of residential battery systems in service and the incremental systems expected to be installed during the 2028-2032 period to determine the forecasted annual OM&A required. OM&A expenditures begin once a system is placed into service and therefore increases over the forecast period as additional units are deployed. Residential BESS OM&A expenditures are forecast at approximately $2.5M in the 2028 Test year and are expected to increase to $8.8M by the end of the rate period.

2.5.3 SMART DEVICE SUPPORT

2.5.3.1 PROGRAM DESCRIPTION

Smart Device Support Investments support back-end integration costs such as platform hosting costs, and cellular data costs. These investments enable Hydro One to track, monitor, and control DERs and other distribution system monitoring & outage restoration devices. The expenditures in this program comprise the following:

Cellular Payments for Smart Devices & Related IT Expenditures

Modernization of the distribution system, including the use of remotely operable devices and communicating fault indicators, enables Hydro One to reduce the impact of customer interruptions. These technologies allow system operators and lines staff to quickly identify and isolate faulted sections of the distribution system. This investment covers the costs associated with maintaining cellular communications to remote switches, reclosers, communicating fault indicators and distribution stations. Other IT expenditures include expenses related to IED Remote Event Retrieval via SCADA Event Gateway. The installation of SCADA Event Gateways eliminates the current need for field staff to be manually dispatched by system control following a protection operation to retrieve fault information for analysis.

DERMS and ADMS Application Sustainment

Hydro One is migrating to the next version of its Advanced Distribution Management System (ADMS) which includes advanced analytics, consolidates the existing Outage

Management System (OMS) to a single platform, and centralizes the management of all distribution assets. In addition, Hydro One also requires specific software for DER Monitoring, aggregation and dispatch. Both are net new investments that comprise DERMS and ADMS OM&A. Details are provided below.

In 2028, Hydro One plans to implement Schneider Electric's suite of products that enable the latest version of ADMS. This is needed to harmonize several disparate systems currently utilized for Dx System Control and are nearing end of life. The upgrades are needed to support continued stable and reliable operations. The proposed version of ADMS will harmonize the following components: SCADA, DMS, OMS, and DERMS modules, Mobile Field Client, and WebDMD for corporate users.

This investment supports the continued use of DERMS in 2028 and beyond, which manages the dispatch of flexible resources (e.g. demand response). The expenditures in this program also includes internal resources providing first- and second-level support, vendor maintenance and support services, and activities required to maintain compliance with Hydro One's cybersecurity standards.

2.5.3.2 PROGRAM EXPENDITURES

Table 38 below outlines the 2023-2025 actuals, 2026-2027 bridge and 2028 test year expenditures for Smart Devices & DER Support in Smart Grid Investments OM&A.

Table 38 - Summary of Smart Grid Investments OM&A ($M) - Smart Devices & DER Support

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Cellular Payments for Smart Devices & Related IT Expenditures	0.3	1.0	1.1	1.3	1.4	1.5
DERMS / ADMS Sustainment	0.0	0.0	0.0	0.8	1.4	1.1
DER Testing Laboratory	0.0	0.0	0.2	0.2	0.2	0.0
Total	**0.3**	**1.0**	**1.3**	**2.2**	**3.0**	**2.6**

The 2028 Test year expenditure for Smart Devices and DER Support is $2.6M, a $2.3M increase over 2023 actuals, and a $1.0M increase over the average of the last rate period (2023-2027). This increase is primarily attributable to the DERMS sustainment investments. DERMS and ADMS sustainment is a new cost requirement, with no expenditures incurred from 2023 to 2025 as the platforms were not yet in service. Expenditures begin at $0.8M in 2026 and increase to $1.4M in 2027 as the new capabilities are implemented, before declining to a steady-state level of $1.1M in 2028. The 2028 forecast is approximately 72%, above the 2023–2027 annual average of $0.4M, reflecting the ongoing software, vendor support, internal support and cybersecurity costs required to sustain the operational platforms.

The 2028 Test year forecast for Cellular Payments for Smart Devices & Related IT Expenditures is $1.5M, which is $0.2M higher than the 2027 Bridge Year and $1.2M higher than 2023 historic actuals. Expenditures increased significantly in 2024, primarily due to consolidation of cellular and dark fiber charges previously managed by several maintenance programs, as well as investments in network infrastructure redundancy designed to mitigate the risk of a single contingency affecting Hydro One's fleet of grid modernization devices.

Furthermore, this program is largely driven by the number of devices requiring cellular connectivity and monitoring services. Hydro One has approximately 8,600 distribution devices equipped with remote monitoring capabilities as of Dec 31, 2025, including switches, reclosers, communicating fault indicators, and distribution station equipment. This is higher than roughly 6200 devices in 2023. Hydro One continues to expand the deployment of remotely monitored devices under its capital investment plan in Distribution Automation and Sectionalizing Program (DSP Section 3.11, D-SS-05), DER Hosting Capacity (DSP Section 3.11, D-SS-07), and Real Time Distribution Station and Feeder Monitoring Program (DSP Section 3.11, D-SS-10). As a result, the associated cellular communication and IT support costs are expected to increase. Based on the forecast number of connected devices, program expenditures are forecast at $1.5M in the 2028 Test Year.

DER Testing Laboratory expansion is expected to be completed by 2027 and therefore does not form part of the 2028 Test year.

DISTRIBUTION DEVELOPMENT OM&A

1.0 SUMMARY OF DEVELOPMENT OM&A

Distribution Development OM&A consists of expenditures required for Hydro One to meet its service commitments and regulatory obligations, including: the connection of load or generation customers, the effective monitoring of the impact of Distributed Energy Resources (DERs), and the overall safe, reliable and efficient operation of the distribution system.

Hydro One manages its Distribution Development OM&A expenditures in the following categories which are detailed below:

1. **Engineering and Technical Studies**: gathering and analyzing system data to identify capability and reinforcement needs.
2. **DER Connections**: studies, coordination, project estimating, and power quality monitoring to support the connection of distributed generation.
3. **Distribution Standards Program**: maintaining and developing distribution technical standards for power system assets.
4. **Research Development and Demonstration (RD&D)**: supporting Hydro One's evaluation and advancement of capabilities across early and growth stages of the technology innovation lifecycle, applicable to assets, methods and practices.
5. **Customer Power Quality Program**: addressing industrial customer power quality concerns through monitoring, audits and investigations.

Hydro One establishes expenditure levels for the Development OM&A work programs based on historical volumes and costs and future anticipated needs. Table 1 provides a summary of Hydro One's Distribution Development OM&A expenditures for the Historical Actuals (2023-2026),[1] Bridge Year (2027), and Test Year (2028).[2]

[1] Actual (2023-2025) and Forecast (2026).
[2] 2029 to 2032 OM&A is established mechanistically, using an index-based approach, in accordance with the Customer IR framework described in Exhibits A-04-01 and A-04-03.

Expenditure variance discussions throughout this exhibit rely on a comparison of the forecasted Test Year against 2023 actual expenditures and the average for the 2023-2027 rate period.

Table 1 - Summary of Development OM&A ($M)[3]

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Engineering and Technical Studies	2.3	2.4	2.6	2.5	2.5	3.1
DER Connections	2.3	2.1	2.4	2.9	3.0	5.9
Distribution Standards Program	0.9	1.2	0.7	1.7	1.7	2.9
Research Development & Demonstration	4.1	4.3	5.0	5.3	5.0	5.6
Customer Power Quality Program	0.0	0.0	0.0	0.1	0.1	0.1
Total	**9.5**	**10.0**	**10.6**	**12.4**	**12.4**	**17.6**

The 2028 Test Year expenditure for Distribution Development OM&A is $17.6M, an $8.1M increase over the 2023 actuals and a $6.6M increase over the average of the 2023-2027 rate period. Higher forecasted expenditures for 2028 are primarily due to increased expenditures for the DER Connections and Distribution Standards Program. Section 2.0 below provides detailed program descriptions and variance explanations for each of the Development OM&A programs.

The establishment of Development OM&A expenditures is guided by the planning process described in DSP Section 3.7 to ensure that expenditures are managed to meet customer, operational and regulatory requirements.

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

2.0 DEVELOPMENT OM&A PROGRAM DESCRIPTIONS AND VARIANCE DISCUSSION

2.1 ENGINEERING AND TECHNICAL STUDIES

PROGRAM INTRODUCTION

The Engineering and Technical Studies program involves the gathering and analysis of system data to identify capability and reinforcement needs. This program also sustains and supports the tools that are used to perform various technical studies.

Engineering and technical studies are critical to the effective management of the distribution system and are required to support capital investment decisions – both planned (e.g., system modifications, protection coordination) and unplanned (e.g., new connections, power quality complaints) as documented in DSP Section 3.7. These studies ensure Hydro One can effectively analyze the needs of the system to meet customer reliability and service quality requirements. They also ensure continued performance of the distribution system by mitigating the risks of electrically overloading system assets that can result in equipment failure, voltage degradation, and increased frequency of outages.

The Engineering and Technical Studies program also encompasses the ongoing support and maintenance of the distribution design tool, which performs design and estimating work to support customer and internally-driven Distribution Lines activities. These activities impact many System Service, System Access and System Renewal investments across Hydro One's Distribution System Plan (DSP Section 3.1). A list of the relevant Investment Summary Documents (ISDs) per DSP Section 3.11 are listed in Table 3 below.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for the Engineering and Technical Studies program based on historical study volumes, future study volume increases based on planned expenditures and vendor-specific estimates of design tool support activities. Table 2 provides a summary of the Engineering and Technical Studies OM&A

expenditures for the Historical Actuals (2023-2026), Bridge Year (2027), and Test Year (2028).

Table 2 - Summary of Engineering and Technical Studies OM&A ($M)

Program	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Engineering and Technical Studies	2.3	2.4	2.6	2.5	2.5	3.1

The 2028 Test Year expenditure for Engineering and Technical Studies OM&A is $3.1M, a $0.8M increase over the 2023 actual expenditures and a $0.6M increase over the average of the 2023-2027 rate period.

The 2028 Test Year expenditures are higher due to the additional data gathering, analysis, and technical studies required to support increasing investments in the following System Service, System Renewal and System Access areas:

- Load Growth (DSP Section 3.11, D-SS-01) and Demand Investments (DSP Section 3.11, D-SS-03): Load flow and short circuit studies to determine appropriate thermal rating of equipment, voltage performance, and protective device parameters. For Load Growth, such investments target distribution system capacity increases across a broader geographical area. For Demand investments, such investments typically target local system capacity.
- Reliability Improvement Investments (DSP Section 3.11, D-SS-02): Review of historical outage location and short circuit studies to determine suitable device parameters.
- Energy Storage Solutions (DSP Section 3.11, D-SS-04): Load flow, short circuit and historical outage location review to determine battery, inverter and protective device parameters.

- Distribution Automation & Sectionalization (DSP Section 3.11, D-SS-05): Review of historical outage location and short circuit studies to determine suitable device parameters.
- Power Quality and Stray Voltage (DSP Section 3.11, D-SS-06); Distribution Station Renewal (DSP Section 3.11, D-SR-04); New Load Connections, Upgrades and Cancellations (DSP Section 3.11, D-SA-02), Distribution Lines Sustainment (DSP Section 3.11, D-SR-10), and; Voltage Consolidation (DSP Section 3.11, D-SR-17): Load flow and short circuit studies to determine appropriate thermal rating of equipment, and protective device parameters. In the case of Line Sustainment, studies will also look at historical outage information

Table 3 compares the total capital expenditures for the investments supported by these studies from 2023-2027 actual/forecast/bridge to 2028-2032 forecast. As capital investment increases, corresponding increases in the technical studies budget are necessary to support that investment:

Table 3 - Comparison of Investments supported by the Technical Studies Program in 2023-2027 Compared to 2028-2032

Applicable ISDS (DSP Section 3.11, ISD)	2023-2027 Aggregate Expenditures ($M Forecast/Actual)	2028-2032 Aggregate Expenditures ($M Net)	% Increase 2028-2032 Vs 2023-2027
D-SS-01, D-SS-02, D-SS-03, D-SS-04, D-SS-05, D-SS-06, D-SR-04, D-SR-10, D-SR-17, D-SA-02	2,418.9	4,973.3	105.6%

2.2 DISTRIBUTED ENERGY RESOURCE (DER) CONNECTIONS

PROGRAM INTRODUCTION

The DER Connections program addresses the study, coordination, project estimating, and sustainment of power quality monitoring required for the connection of DERs.

The DER Connections program is required to comply with Hydro One's Distribution License obligation to make reasonable efforts to connect DERs in accordance with the

Distribution System Code. To ensure the reliable connection of DERs, this program includes:

- Development of connection impact assessment reports that identify system upgrades, if any, required to enable a DER connection and to mitigate any potential negative impacts to distribution customers prior to the connection being made;
- Development of cost estimates for the overall connection; and
- Required program coordination activities that are not directly related to individual connections, such as sustainment of power quality monitoring capability.

Following the termination of the Feed-in Tariff program in 2018, DER activity shifted to three main categories: (i) behind-the-meter load displacement DERs participating in the IESO's Industrial Conservation Initiative program; (ii) renewable DERs under the Ontario Net Metering program as regulated by Ontario Regulation 541/05 (O. Reg. 541/05); and (iii) refurbishment and upgrade of legacy non-utility generators using water as an energy resource.

Looking ahead, these DER activities are expected to continue, with additional DER activity expected, driven by the IESO's Long Term Procurement program under the Resource Adequacy Framework. The first phase (LT1) is now complete with projects coming into service between 2026 and 2028. Additional generation is expected under the second phase (LT2) to meet energy needs in 2030 and beyond. Most recently, in 2025, the province of Ontario announced solar photovoltaic incentives targeting participants who are interested in behind-the-meter solar installations to displace load.

Table 4 shows the number of DER projects for the 2023 to 2027 rate period and the forecast number of projects for 2028 to 2032, which incorporates the findings of 'Ontario's Distributed Energy Resources Potential Study' prepared for the IESO by Dunsky.

Table 4 - DER Project Volumes

Project Type		Act/Fcst[4] 23-27	2028	2029	2030	2031	2032	Fcst 28-32
Non-Renewable Energy Projects	**Mid/Large DER**	37	32	32	32	32	32	160
	Small DER	6	10	10	10	10	10	50
	Micro	40	20	20	20	20	20	100
Renewable Energy Projects	**Mid/Large DER**	18	16	16	16	16	16	80
	Small DER	277	285	285	285	285	285	1,425
	Micro	4,804	1,615	1,615	1,615	1,615	1,615	8,075

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for DER Connections based on historical study costs, and forward-looking estimates of anticipated DER connection volumes. Table 5 provides a summary of the DER OM&A expenditures for the Historical Actuals (2023-2026), Bridge Year (2027), and Test Year (2028).

Table 5 - Summary of DER OM&A ($M)

Program	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
DER Connections	2.3	2.1	2.4	2.9	3.0	5.9

The 2028 Test Year expenditure level for DER Connections OM&A is $5.9M, a $3.6M increase over the 2023 actual expenditures and a $3.3M increase over the average of the 2023-2027 rate period.

This increase is primarily driven by the expected rise in DER Connections volumes outlined in Table 4 above, a new need to assess constrained feeders and perform studies to increase DER Hosting Capacity, supporting the new DER Hosting Capacity map and improvements to the systems used to administer DER applications. These costs are

[4] "Actual" refers to Actual (2023-25) and Forecast (2026-27) volumes.

anticipated to be partially recovered through external revenues generated from applicants via Connection Impact Assessment fees.

2.3 DISTRIBUTION STANDARDS PROGRAM

PROGRAM INTRODUCTION

Hydro One maintains its Distribution technical standards and guidelines under the Distribution Standards program. This program supports the planning, design, installation, operations, and maintenance of Hydro One's distribution system.

The scope of the program includes: (i) maintaining and updating current standards for power system assets such as stations, transformers, lines, and other distribution equipment; (ii) developing new standards in support of new and evolving technologies and designs, such as 44kV Padmounted Distribution Stations; (iii) ensuring that distribution technical standards incorporate company policies and requirements necessary for compliance with regulations such as the Electrical Distribution Safety Regulation (O. Reg. 22/04) and the Electrical Safety Code (O. Reg. 164/99); and (iv) monitoring and influencing emerging industry standards through participation in standards development associations, including the CSA Group (formerly the Canadian Standards Association) and Institute of Electrical and Electronics Engineers (IEEE) Standards committees.

Hydro One's Distribution technical standards define suitable equipment and provide consistent design approaches. This provides clear direction for field employees to carry out work procedures that safeguard utility employees and the public where electrical equipment is installed, operated and maintained. The use of repeatable and consistent designs provide flexibility for resourcing work, standardizes maintenance approaches to avoid additional costs from design variations, and enables cost savings from bulk purchasing using standardized technical specifications.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for Distribution Standards activities based on historical standards volumes, historical costs, and forward-looking volume estimates based on anticipated priorities. Table 6 provides a summary of the Distribution Standards OM&A expenditures for the Historical Actuals (2023-2026), Bridge Year (2027), and Test Year (2028).

Table 6 - Summary of Distribution Standards OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Distribution Standards Program	0.9	1.2	0.7	1.7	1.7	2.9

The 2028 Test Year expenditure level for Distribution Standards Program is $2.9M, a $2M increase over the 2023 actual expenditures and a $1.6M increase over the average of the 2023-2027 rate period.

The increase is primarily required to update existing standards and guidelines. The expenditures are also driven by the need to develop additional standards to support the adoption of new and evolving technologies and designs, including power system assets, as well as sensing, protection, control, and telecommunication systems.

2.4 RESEARCH DEVELOPMENT AND DEMONSTRATION (RD&D)

PROGRAM INTRODUCTION

The RD&D program supports Hydro One's adoption of new technologies and industry practices to improve operational effectiveness, safety, and system reliability.

The RD&D program addresses:

i. operational needs by resolving technical challenges experienced by Hydro One to improve the management of existing distribution facilities to deliver safe and reliable supply to customers;
ii. strategic needs by engaging in research and demonstration of emerging technologies and understanding their impacts; and
iii. other electricity industry changes arising from innovation and policy initiatives, including grid modernization, and the OEB's Innovation Sandbox, including assessing flexibility initiatives.

The following examples are representative of distribution related initiatives supported through the RD&D program:

- Assessing and investigating the benefits and risks of future-oriented emerging technologies which are new to the industry or present material growth opportunities and/or risks. The main areas of emerging technologies that are a focus of current RD&D efforts are:
    - **Grid-edge resource integration:** This area focuses on technologies emerging at the interface between the grid and the customer, including DER, energy storage, advanced metering infrastructure, electric vehicles, and smart home devices. Hydro One is collaborating with industry and research partners to enhance capabilities in integrating these technologies, and assessing opportunities that support grid modernization, customer choice, and flexibility.

- Electrification: Hydro One is actively monitoring electrification trends and collaborating in a variety of industry forums on the subject, such as Electric Power Research Institute (EPRI) and CEATI International (originally the Centre for Energy Advancement through Technological Innovation). These activities support planning for electricity demand growth across various sources of electrification. For example, in anticipation of increased electrification of transportation, this program supports the development of electrical vehicle adoption forecasts and related planning tools to inform distribution system needs.

- Investigating better ways of doing current work, with the potential to improve efficiency, health, and safety for ongoing work and maintain the reliability of the distribution system. The main areas of "innovative" technologies that are a focus of current RD&D efforts are:
    - **Industry Engagement and Research:** Ongoing research into emerging issues related to technical impacts of public policy decisions.
    - **Reliability and Resiliency Practices:** Ongoing research to help develop capabilities and update the knowledge base used by utilities to achieve service reliability and resiliency goals to contribute to maintaining and improving distribution system reliability as well as system resiliency during major weather events.

- Asset Management Practices: Ongoing review with industry partners of Hydro One's asset management practices and tools used by other utilities and maintenance policies and practices to determine common practices and areas for improvement or further study.

Much of this research is conducted through partnerships with industry, including EPRI and CEATI on a subscription basis. This participation model is a cost-effective approach that allows Hydro One to leverage joint funding with other utilities, share risks, and access to the broader expertise and operational experience of companies with similar interests or challenges.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for RD&D activities based on historical research studies and engagements, and forward-looking estimates based on anticipated priorities as described above. Table 7 provides a summary of the RD&D OM&A expenditures for the Historical Actuals (2023-2026), Bridge Year (2027), and Test Year (2028).

Table 7 - Summary of RD&D OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Research Development & Demonstration	4.1	4.3	5.0	5.3	5.0	5.6

The 2028 Test Year expenditure level for RD&D OM&A is $5.6M, a $1.5M increase over 2023 actual expenditures and a $0.9M increase over the average of the 2023-2027 rate period.

The increase in expenditures is attributable to the further study and assessment of new technologies and industry practices, including with respect to grid-edge resource integration and electrification as described above, and to provide access to and facilitate industry research and engagement with organizations, including EPRI and the CEATI to obtain insights into new and emerging technologies and operational and strategic needs, and challenges associated with incorporating said technologies and needs.

2.5 CUSTOMER POWER QUALITY PROGRAM

PROGRAM INTRODUCTION

The Customer Power Quality program supports reliability for Hydro One's industrial customers, including automotive plants, manufacturing facilities, and material processing plants. Voltage sags due to faults occurring on power systems are a principal cause for many equipment and process disruptions experienced by industrial customers. This issue is common within the distribution industry at large, and an established mitigation approach involves the industrial customer making relatively minor retrofits and design changes to equipment controls, informed by system data and analysis provided by the utility.

Through this program, Hydro One provides industrial customers with detailed information about their power quality environment. This enables a coordinated approach to managing

power quality performance while recognizing the constraints and limitations of the power delivery system.

The Customer Power Quality program includes:

- expanding monitoring capability on the distribution system to enhance visibility of power quality at customer delivery points, and
- providing third-party audits to assist customers to identify ways to improve their equipment's tolerance of power quality events.

The expansion of power quality monitoring capability is achieved by leveraging customers' existing retail revenue meter functionality, to provide power quality data into Hydro One's power quality monitoring network. The benefits of this monitoring at customer's site include more efficient and faster power quality event investigations, as well as better understanding of plant equipment sensitivity to inevitable power quality disturbances to identify opportunities in the plant to improve power quality tolerance.

Third-party audits consist of an onsite inspection of customer facilities and equipment to identify the power quality resiliency weak links, analysis of available power quality data, and specific recommendations for targeted mitigating measures to improve equipment resiliency to such events. Improving power equipment resiliency reduces the frequency of equipment tripping and any associated production losses for companies.

EXPENDITURE FORECAST LEVEL

Hydro One develops forecast expenditure levels for the Customer Power Quality program based on historical work program volumes. Table 8 provides a summary of the Customer Power Quality OM&A expenditures for the Historical Actuals (2023-2026), Bridge Year (2027), and Test Year (2028).

Table 8 - Summary of Customer Power Quality Program OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Customer Power Quality Program	0.0	0.0	0.0	0.1	0.1	0.1

The 2028 Test Year for Distribution Development Customer Power Quality Program OM&A forecast is slightly higher relative to historic expenditures to support customers experiencing power quality concerns but is in-line with the test year forecast.

DISTRIBUTION CUSTOMER CARE OM&A

1.0 SUMMARY OF DISTRIBUTION CUSTOMER CARE OM&A

Hydro One's distribution system is among the largest in North America, providing approximately 1.5 million customers in many of Ontario's hardest-to-reach locales with safe and reliable connections to the electricity they need. This includes residential, seasonal, small business, large distribution-connected business customers, and customers in Indigenous communities across Ontario as described in SPF Section 1.6.3.2.

As customer expectations and the electricity sector continue to evolve, Hydro One adapts its customer service programs, processes and tools to support the needs of its customers. Distribution Customer Care OM&A funds the activities, resources, tools and programs required to deliver customer service, issue accurate bills, manage customer accounts and payments, support customer affordability, and enable customer participation in emerging energy and flexibility programs. It is organized into the following program areas:

- **Customer Relations Management** encompasses ongoing communications, frontline customer service and customer experience oversight. It also supports customers with increasingly complex billing, connection, load growth and energy management needs, and provides dedicated relationship management for large distribution customers to help advance their electrification and growth objectives.
- **Meter to Cash** manages the end-to-end revenue cycle, including meter reading, meter-data validation, billing, settlements, payment processing, collections, field support, third party support services, financial assistance and net bad debt management. These activities help ensure that customers receive timely and accurate bills and that customer accounts and payments are effectively managed and recovered.
- **Service Enhancements** include initiatives that improve customer service delivery and customer experience, including customer communications and education, customer research, workforce training, Indigenous engagement and targeted improvements to customer-facing digital channels and self-service tools.

- **Distributed Energy Resources (DER) and Customer Flexibility Enablement** covers value-added services, local energy-efficiency programs, DER customer engagement and the capabilities required to enable customer participation in DER and electricity market opportunities. These initiatives support customer affordability and choice while contributing to a more flexible, resilient and efficient electricity system.

Collectively, these programs provide customers with the following benefits:

- **Accessible and responsive service** through the customer Contact Centre, digital channels, self-service tools, and dedicated account support for large distribution customers.
- **Timely and accurate billing** supported by meter data collection, validation, settlements and billing processes.
- **Customer affordability support** through flexible payment arrangements, customer education and access to finance assistance programs, including Low-Income Energy Assistance Program (LEAP) and the Ontario Electricity Support Program (OESP).
- **Effective revenue management** that helps contain bad debt and reduce unpaid balances borne by customers.
- **Greater customer choice and participation** through billing and payment options, energy management information, and participation in energy-efficiency, DER and flexibility programs.
- **Continuous service improvement** informed by customer feedback, research, operational insights and targeted enhancements to customer-facing processes and tools.

Hydro One is also implementing complementary capital investments to address changing customer needs and expectations and improve customer satisfaction. These initiatives are described in GSP Section 4.11, G-GP-07.

Table 1 provides a summary of Hydro One's Distribution Customer Care OM&A expenditures for the Historical Period (2023-2026), Bridge Year (2027), and Test Year (2028).

Table 1 - Summary of Customer Care OM&A Allocated to Distribution ($M)[1]

	Historical				Bridge Year	Test Year
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Customer Relations Management	**28.5**	**30.1**	**31.4**	**38.8**	**39.7**	**41.3**
Call Centre Operations	25.2	26.6	28.0	32.7	33.5	34.2
Large Customer Care Staffing	3.3	3.5	3.4	6.0	6.2	7.1
Meter to Cash	**57.4**	**66.5**	**61.4**	**68.1**	**69.2**	**78.4**
Billing, Settlements and Meter Reading	24.5	25.8	21.8	25.6	26.0	29.6
Collections and Collections Support	24.0	31.3	30.1	31.5	31.0	35.4
Third Party Support	8.9	9.4	9.5	10.9	12.2	13.5
Service Enhancements	**7.7**	**8.1**	**8.1**	**8.4**	**8.1**	**7.9**
DER and Customer Flexibility Enablement	**1.2**	**1.9**	**1.1**	**0.7**	**3.0**	**12.0**
Total	**94.8**	**106.7**	**102.1**	**115.9**	**120.0**	**139.6**

The 2028 Test Year expenditure for Customer Care OM&A allocated to Distribution is $139.6M, a $44.7M increase over 2023 actuals, and a $31.6M increase over the average of the last rate period (2023-2027).

The increase over the 2023-2027 period reflects a combination of customer growth, increasing service complexity, workforce-related changes, vendor-driven cost increases and evolving customer and regulatory requirements. During this period, Hydro One continued to maintain customer service and revenue-cycle operations while responding to

[1] Figures presented in the table may not sum to the total shown due to rounding.

increasingly complex customer needs, supporting customer affordability initiatives, and preparing for future customer participation in emerging energy and flexibility programs. The 2028 forecast builds on these trends and includes targeted investments to support future customer and system needs. These investments include customer flexibility and DER enablement initiatives that support customer affordability, choice and participation in electricity markets, as well as temporary transition requirements associated with the implementation of AMI 2.0. At the same time, Hydro One continues to maintain customer service and revenue management activities to serve a growing customer base with increasing service complexity. Detailed descriptions and variance explanations for each program and subprogram are provided in the sections below.

Hydro One monitors customer feedback and several key operational and service performance measures, including service quality and customer satisfaction as described in DSP Section 3.5.2.1. These measures continue to provide insights into customer needs and service performance, helping Hydro One identify opportunities to improve business processes, service delivery, and customer experience.

2.0 CUSTOMER RELATIONS MANAGEMENT

The Customer Relations Management program supports Hydro One's interactions with mass market and large distribution customers through customer communications, customer service, customer experience oversight, and relationship management activities. The program is centered on engaging customers with relevant and timely information through channels that align with their preferences. This program enables efficient and responsive handling of inquiries, increasing awareness of service options (including billing formats and electricity pricing plans), promoting available financial assistance programs, and helping customers better understand and manage their electricity consumption.

The program comprises two subprogram areas: (i) Call Centre Operations and (ii) Large Customer Care Staffing.

The mass market portion of the Customer Relations Management program, Call Centre Operations, encompasses several core functions, including the Contact Centre, Escalations, Quality Assurance and Customer Experience. Together, these functions are designed to deliver consistent, high-quality customer service while improving operational efficiency through the monitoring and analysis of inbound inquiries, transactional surveys, and other customer feedback mechanisms.

The large customer portion of the Customer Relations Management program, Large Customer Care Staffing, includes dedicated relationship management and coordinated support for large distribution customers. It also supports the delivery of customer solutions, flexible market enablement, and choice. These functions enable electrification, decarbonization, resilience, and cost management objectives and transform large distribution customers into active system partners. Building strong relationships with large distribution customers enables Hydro One to proactively identify evolving customer needs, support customer growth and electrification initiatives, and identify opportunities to advance long-term system planning, grid modernization and flexibility solutions.

In addition to these operational functions, the program covers the design and oversight of technology-enabled initiatives that support ongoing engagement, business process assessment, and performance monitoring and measurement activities. These efforts drive continuous improvement in customer experience and service delivery efficiency.

As customer needs and expectations continue to evolve alongside broader societal and industry trends, Hydro One anticipates the need to further tailor services to individual customer preferences to enrich the customer experience. To remain responsive to customer expectations, policy requirements, and industry developments, the program supports activities that monitor emerging trends, adapt business processes, and leverage technology and process enhancements to manage costs. The program also supports initiatives to improve first-contact resolution and invest in workforce training and upskilling to ensure staff are equipped to meet changing service demands.

2.1 CALL CENTRE OPERATIONS

2.1.1 PROGRAM INTRODUCTION

Call Centre Operations includes the following functions (i) Contact Centre, (ii) Escalations, (iii) Quality Assurance, and (iv) Customer Experience. Each of these functions is described below.

i. Contact Centre

The Contact Centre reflects Hydro One's costs to deliver frontline customer-facing services and account support for call centre services and distributed energy resources (DER) services to Hydro One Customers. Customers communicate with Hydro One across multiple channels, including telephone, interactive voice recognition (IVR), digital, letters, email, social media platforms and through the company's website. In 2025, the call center handled over 2.1 million calls from customers, an increase from 1.7 million calls in 2023. The call center also responded to an average of over 500 emails per month over the 2023-2025 historical period.

ii. Escalations

The Customer Relations Centre (CRC) is responsible for administering Hydro One's Customer Complaint and Dispute Resolution process. The CRC receives, investigates, and resolves customer complaints in a fair, reasonable, and timely manner, working across business units to achieve customer-centric outcomes that are consistent with regulatory requirements and company policies. In fulfilling this role, the CRC ensures clear and transparent communication with customers and external stakeholders, analyzes complaint trends to support continuous improvement, and acts as an internal advocate for customers to promote service quality, accountability, and consumer confidence.

iii. Quality assurance

This function provides quality assurance oversight for Contact Centre operations by conducting systematic reviews of frontline customer interactions to assess compliance, accuracy, and service standards. It supports performance improvement through structured feedback, coaching, and training enablement, and oversees the

implementation of changes to systems and business processes. The function also designs and delivers training for new and continuing learning and development, analyzes operational and customer data to identify trends, risks, and improvement opportunities, and supports continuous improvement to promote consistent customer outcomes.

iv. Customer Experience

This function provides oversight of Customer Experience and drives continuous improvement through the integrated use of speech analytics, Voice of the Customer (VoC) data, and operational insights. It systematically analyzes customer interactions alongside VoC inputs, such as surveys, call monitoring, and outage related feedback, to identify emerging issues, root causes of customer dissatisfaction, and potential risks to service quality or compliance.

The function enables cross functional alignment by consolidating insights from multiple channels into centralized reporting and tracking frameworks, providing a comprehensive view of customer experience trends. It supports the connection between customer feedback and operational outcomes by identifying root causes, monitoring the effectiveness of corrective actions, and ensuring a consistent “closed loop” approach between insight and action. Outputs from this function are used to inform operational decision making, guide continuous improvement initiatives, and support transparent, consistent reporting.

Recent outcomes demonstrate impact across both employee and customer experience. Targeted employee engagement initiatives have contributed to improvements in employee experience from 2024 to 2025. In addition, the introduction of innovative training solutions, including virtual reality (VR), has enhanced onboarding and skill development by providing immersive, end to end exposure to customer and field processes. Hydro One’s VR training program has received industry recognition through a Chartwell Award.

From a service delivery perspective, enhanced analytics capabilities have been implemented across customer interaction channels, including phone, email, and webchat,

to systematically assess high volumes of interactions. These insights have strengthened visibility into customer needs and enabled targeted enhancements, including improved coaching and training programs, as well as the automation of quality assurance processes to evaluate 100% of non-subjective voice interactions within the Contact Centre.

Evolving Customer Service Requirements

As the electricity sector continues to evolve, new technologies, pricing options and service offerings are broadening the range and complexity of customer inquiries. Call Centre Operations must adapt its capabilities accordingly to support customers effectively, and provide timely, accurate and accessible information in response to increasingly sophisticated customer needs.

Increasing Complexity of Customer Interactions

Customer inquiries now require greater judgement, system navigation, and technical knowledge than in the past, including:

- analyzing high-bill inquiries across multiple pricing structures (e.g., Tiered, Time-of-Use, Ultra-Low Overnight pricing);
- supporting customers with technologies such as electric vehicle (EV) chargers, heat pumps, and net metering; and
- addressing customer matters the involve coordination across multiple business areas, including billing, connections, and DERs.

This shift contributes to longer average handle time (AHT) and more complex decision-making, requiring enhanced frontline support, training, and performance monitoring.

Growth of DER

Previously niche services such as net metering, load displacement, and battery storage are becoming more prevalent. Net-metered billing, for example, introduces additional complexity, where errors carry higher financial, reputational, and rework impacts.

As adoption of these technologies increases, the Contact Centre requires enhanced training, tools, knowledge management and oversight to enable accurate and consistent customer interactions.

Omni-Channel Expansion and Operational Implications

Over the past five years, Hydro One has expanded from a limited number of channels to a broader omni-channel model, including:

- Voice;
- Live chat;
- Mobile application; and
- Digital self-serve capabilities (e.g., eBilling, move transactions, tree trimming, temporary disconnections, underground cable locates and service upgrades).

Each channel introduces distinct workflows and systems, different skill sets and training needs, and unique quality and customer experience risks. Traditional, call-centric support models are no longer sufficient. The Contact Centre requires integrated operational support, cross-channel performance visibility, and consistent governance to ensure alignment across all engagement points.

2.1.2 EXPENDITURE LEVELS

Call Centre Operations OM&A expenditures for historical, bridge and test years are provided below in Table 2.

Table 2 - Call Centre Operations OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Call Centre Operations	25.2	26.6	28.0	32.7	33.5	34.2

The 2028 Test Year expenditure for Call Centre Operations OM&A is $34.2M, a $9.0M increase over 2023 actuals, and a $5.0M increase over the average of the last rate period (2023-2027).

Call Centre Operations expenditures were largely consistent from 2023 to 2025, with slight increases due to inflation. From 2025 actual ($28.0M) to 2026 forecast ($32.7M), expenditures increase by $4.7M (17%), and forecast expenditures then remain largely consistent between 2026 and the Test Year, 2028.

The increase from 2025 actual expenditures to the 2026 forecast is attributable to a combination of operational, labour, project-related, and external factors. These include the need to replace vacant positions to maintain appropriate staffing levels and sustain reliable service delivery.

In light of growing and sustained customer service workloads, Hydro One has utilized more regular employees to increase internal expertise and knowledge retention. Overall staffing levels remained relatively stable, however, the transition to a greater proportion of regular employees resulted in higher compensation costs. Hiring hall resources continue to provide operational flexibility to address seasonal, peak, project-based and leave replacement requirements.

Temporary resourcing is also required to support major transformation initiatives, including the Advanced Metering Infrastructure (AMI 2.0) program over the 2026-2031 period and the Customer Information System (CIS) program over the 2028-2031 period, as well as to support the transition of project deliverables into sustained operational processes and capabilities.

Forecast expenditures are largely consistent from 2026 to 2028, subject to inflationary growth. This forecast reflects Hydro One’s continued emphasis on prudent cost control and productivity while sustaining service delivery and responding to incremental demands.

2.2 LARGE CUSTOMER CARE STAFFING

2.2.1 PROGRAM INTRODUCTION

Large Customer Care Staffing provides dedicated account management and customer service for Hydro One's large distribution customers. These customers typically have more complex operational, billing, connection, load growth and energy management requirements than mass market customers, often requiring ongoing engagement and coordinated support managed by the Key Accounts Management group as described in SPF Section 1.6.4.2.1.

Funding is required to:

i. Manage Rising Volume and Complexity in the Large Customer Segment

- Address sustained growth in large customer connections, expansions, and DER-related inquiries across an increasingly complex industry framework.
- Maintain service levels by ensuring sufficient resourcing for proactive, end-to-end account management.

ii. Deliver Customer Solutions, Flexible Market Enablement, and Choice

- Support tailored energy solutions that address electrification, decarbonization, resilience, and cost management objectives of large customers.
- Enable customer participation in flexibility markets and innovative programs, transforming customers into active system partners.

iii. Improve Customer Experience and Regulatory Outcomes

- Provide clear accountability and consistent engagement for complex customer projects and initiatives.
- Position Hydro One as a trusted partner, reducing complaints and escalations through early issue identification and improved communication.

2.2.2 EXPENDITURE LEVELS

Large Customer Care Staffing OM&A expenditures for historical, bridge and test years are provided below in Table 3.

Table 3 - Large Customer Care Staffing OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Large Customer Care Staffing	3.3	3.5	3.4	6.0	6.2	7.1

The 2028 Test Year expenditure for Large Customer Care Staffing OM&A is $7.1M, a $3.9M increase over 2023 actuals, and a $2.6M increase over the average of the last rate period (2023-2027).

Large Customer Care Staffing expenditures stayed essentially flat between 2023 and 2025. Forecast expenditures increase in 2026-2028.

In 2026, forecast expenditures increase from $3.4M to $6.0M. During the 2025-2026 period, Hydro One reorganized its customer teams to better serve large customer needs. As part of this reorganization, expenses were reallocated from Transmission to Distribution to ensure appropriate alignment. This expenditure reallocation, coupled with the filling of pre-existing vacancies, results in the above increase of expenditures in 2026.

Expenditures are forecast to increase from $6.2M in 2027 to $7.1M in 2028 to support growth and evolving service requirements within the large distribution customer segment. Over the 2023-2025 period, the large distribution customer population has grown approximately 5-6% annually, and distribution load growth is forecasted to continue as set out in Exhibit D-05-01 Table 1. The scope of account management activities is also expanding as customers seek guidance on electricity Demand Side Management, local energy efficiency programs, and emerging DER flexibility and electricity market opportunities as described in Section 5.0 below. To maintain effective customer support

and relationship management, Hydro One plans to add resources across its Key Accounts Management team in 2028. Apart from normal inflationary impacts, the increase in expenditures in 2028 reflects these additional staffing requirements.

3.0 METER TO CASH

The Meter to Cash program is the full end-to-end revenue cycle turning energy usage into revenue; from meter reading, data validation, billing, invoicing and collection of payment. This is all achieved in accordance with Hydro One's tariff of rates and charges, the Ontario Energy Board (OEB) rate orders, and applicable legislative and regulatory requirements.

The program is organized into three subprogram areas: (i) Billing, Settlements, and Meter Reading, (ii) Collections and Collections Support, and (iii) Third Party Support.

Accountabilities within this program include meter reading, metering infrastructure administration, the validation and management of meter data, customer billing and billing-related exceptions, payment processing and refunds, and the administration of collections activities, including the recovery of outstanding accounts receivable and the delivery of financial assistance to eligible low-income customers through the OEB's LEAP program. It also includes third-party services supporting the billing, metering, payment processing and collections activities.

Automated data collection and billing processes support high levels of accuracy, efficient payment receipt, effective customer communications, and strong cash-flow management, while providing customers with a range of billing and payment options aligned with their needs and preferences.

3.1 BILLING, SETTLEMENTS, AND METER READING

3.1.1 PROGRAM INTRODUCTION

The core functions within the Billing, Settlements and Meter Reading subprogram are described below.

BILLING

The Billing function is responsible for the timely and accurate billing of all customers. Hydro One produces and delivers over 16.7 million bills annually, offering both paper and electronic billing. Additional accommodations are provided to support accessibility requirements, such as enhanced-format bills with larger text.

As the electricity sector continues to evolve, driven by increased electrification and the growing adoption of technologies such as electric vehicles, EV charging infrastructure, and DERs, billing processes must continue to adapt. This includes ensuring billing practices can effectively address increasing complexity, changing consumption patterns, and evolving customer expectations with respect to clarity, flexibility, and accessibility.

SETTLEMENTS

The Settlements function ensures that electricity usage, generation and market transactions are accurately calculated, reconciled, and financially settled among customers, generators, the Independent Electricity Systems Operator (IESO) and other market participants.

The function administers settlement and compliance activities across transmission, generation, and retail customer segments, ensuring accurate financial transactions with the IESO and transmission customers' meter service providers. Responsibilities include administering transmission and wholesale market settlements as a Market Participant, supporting and settling payments for approximately 16,000 embedded generators (microFIT and non-microFIT), and performing retail settlement activities for approximately 11,000 Commercial and Industrial (C&I) customers, including Local Distribution Companies (LDCs) and Large Distribution Accounts (LDAs).

The function also maintains compliance with IESO Market Rules, Codes, and rate structures, while supporting short term and long-term load transfers, embedded LDC declarations, and regulatory proceedings. Hydro One must continuously implement pricing changes, which includes annual generator price changes for non-microFIT, as prompted

by the IESO, as well as from regulator decisions and government policy, while meeting evolving settlement obligations and compliance requirements. These obligations include those set by the Market Rules, Measurement Canada and external audit standards.

In addition, the function supports process improvements, system design and testing, and data analysis associated with settlements activities.

METER READING

The Meter Reading function is responsible for the collection, validation, and processing of meter data for billing and settlement purposes across a large and geographically diverse service territory. Hydro One has approximately 1.47 million meters deployed across the province, the majority of which are read via over-the-air communications. A small subset of customers require manual meter reads due to the limited geographical reach of the network in certain locations.

The Meter Data Management (MDM) team supports both automated meter data collection and manual meter reading processes, for hard-to-reach customers, and utilizes multiple meter data collection and management systems to accommodate different meter types and customer classes. Meter data is validated for completeness, consistency, and accuracy to ensure readiness for billing, with estimation routines applied where required and manual review performed for unresolved exceptions.

Ongoing investments in metering infrastructure, communications, and system modernization support improvements in automation, billing accuracy, outage response, data security, and analytical capability.

3.1.2 EXPENDITURE LEVELS

Billing, Settlements and Meter Reading OM&A expenditures for historical, bridge and test years are provided below in Table 4.

Table 4 - Billing, Settlements and Meter Reading OM&A ($M)[2]

	Historical				Bridge Year	Test Year
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Billing and Settlements	9.2	9.7	9.8	10.6	10.8	11.0
Meter Reading	15.3	16.1	12.0	15.0	15.1	18.5
Total Billing, Settlements and Meter Reading	**24.5**	**25.8**	**21.8**	**25.6**	**26.0**	**29.6**

The 2028 Test Year expenditure for Billing, Settlements and Meter Reading OM&A is $29.6M, a $5.0M increase over 2023 actuals, and a $4.8M increase over the average of the last rate period (2023-2027).

From 2023 to 2025, Billing and Settlements expenditures increased from $9.2M to $9.8M. These increases continue into the forecast period to manage the increase in demand and complexity discussed above, with forecast expenditures of $11.0M in the Test Year, 2028.

From 2023 to 2025, Meter Reading expenditures decreased from $15.3M to $12.0M due to a temporary reduction in meter read frequency, which was done to manage OM&A envelope spending at the time but is not sustainable, and the read frequency was therefore adjusted in 2026 to achieve appropriate billing accuracy. This results in the 2026 forecast returning to historical levels ($15.0M). From 2027-2028, the Meter Reading expenditure forecast increases from $15.1M to $18.5M. This $3.4M increase is driven by the transition to AMI 2.0 and related integration costs. There is additional work to support this transition, including the resources required relating to the technology and supporting the AMI 1.0 and 2.0 meters during the transition period. There will be a reduction in resources subsequently required in outer years of the rate period, once the transition has been fully completed.

[2] Figures presented in the table may not sum to the total shown due to rounding.

In the forecast years, expenditures in the above functions are expected to increase to maintain the resourcing capacity and capabilities required to support the increased volume and complexity of work discussed above, in addition to the following:

- Improvement of online self-service capabilities through our myAccount portal, which can include expanded online billing and payment capabilities, conservation and usage management;
- Increase in paperless versus paper correspondence with customers such as via email, text and customer service myAccount portal;
- Increase paperless billing enrolments, relying less on postage and paper costs;
- Integrated smart grid technology with update of infrastructure; and
- Improved network communication ability to increase the number of meters to be read over-the-air. It is expected that Field Support activities will continue around manual meter reading in more remote areas. Meter validation checks will continue, such as with high bills, off-cycle reads and rate checks, as well as with meter investigations due to communication failure and resolution.

3.2 COLLECTIONS AND COLLECTIONS SUPPORT

3.2.1 PROGRAM INTRODUCTION

The core functions within the Collections and Collections Support subprogram include (i) Collections, (ii) Field Support, (iii) Regulatory Compliance (LEAP), and (iv) Net Bad Debt. Each of these functions are described below.

COLLECTIONS

The Collections function includes activities related to monitoring and recovering amounts owing on customer accounts, as well as administering financial assistance programs such as the LEAP and the OESP. Hydro One's collections program is designed to balance effective revenue recovery with customer support by providing flexible payment arrangements and access to assistance program, while minimizing bad debt expense.

To support customers with collections related inquires, Hydro One provides access to dedicated Customer Service Representatives on business days from 7:30 a.m. to 8:00

p.m. In addition, customers have 24/7 access to collections information through an interactive voice response (IVR) system, Hydro One Mobile application, and the myAccount Customer Self-service portal. These channels provide customers with the ability to make and report payments and view their account balances.

In addition to the activities described above, the Collections function undertakes the following ongoing responsibilities to encourage timely payment, identify at-risk accounts, and support the recovery of arrears:

- managing and monitoring approximately 11,427 commercial accounts with security deposits, including conducting annual security deposit reassessments;
- referring approximately 18,000 accounts annually to external collection agencies;
- establishing arrears payment agreements, equal payment plans, and customized payment arrangements tailored to individual customer circumstances; and
- educating customers on financial assistance programs, including LEAP and OESP.

FIELD SUPPORT

The Field Support function consists of customer care activities in the field, including disconnection of electricity due to non-payment, reconnection when payment is received, door hanger deliveries, investigation of high bill inquiries, and other services that require an on-site field visit.

The use of remote disconnection functionality reduces the need for field visits, lowers operational costs, and mitigates the risk of further bad debt accumulation. Remote reconnection capabilities also support compliance with the OEB performance standard requiring reconnection within two business days of payment receipt. In many cases, reconnection can be completed almost immediately upon payment, without the need for a site visit, thereby improving the customer experience. As additional smart meters are upgraded to include remote control functionality, the use of remote disconnections and reconnections is expected to increase.

REGULATORY COMPLIANCE (LEAP)

The Regulatory Compliance function supports compliance with regulatory requirements associated with customer affordability and access to financial assistance. In accordance with OEB requirements set out in EB-2008-0150[3], Hydro One contributes 0.12% of its Distribution revenue requirement annually to LEAP, which provides emergency relief to eligible low-income customers. The United Way of Greater Simcoe manages this fund as Hydro One's lead agency. Depending on customer demand and volume of LEAP applications that meet the eligibility criteria, Hydro One provides funding in excess of this amount.

In partnership with the IESO, the OEB and other utilities, Hydro One supports customers who are sensitive to cost increases, advancing a fair, inclusive and affordable electrified future for Ontario. Hydro One continues to engage with customers to foster transparency and build trust.

Hydro One delivers practical, sustainable solutions that balance business objectives with customer needs, including:

- Providing eligible income-qualified customers with free baseboard smart thermostats, in partnership with the OEB Innovation Sandbox, to participate in demand response programs;
- Funding low-income customers through the LEAP;
- Providing personalized education offerings on affordability through LEAP and OESP;
- Supporting on-reserve customers in First Nations communities through the IESO's Save on Energy programs; and
- Enhancing Get Local visits with First Nation community members to provide information on, and assistance with, various support programs and directly address any concerns.

[3] Report of the Board on Low Income Energy Assistance Program, EB-2008-0150, March 10, 2009, p.10

Hydro One continues to strengthen its Customer Assistance Program through proactive education and outreach with social and community-based organizations while advocating for vulnerable customers and those who may face greater challenges in the future.

NET BAD DEBT

The Net Bad Debt function supports the prudent management of uncollectible accounts by forecasting expected credit losses and monitoring customer payment performances. Hydro One is focused on helping customers stay current with their bills and providing a variety of payment options to minimize arrears and support customer affordability. The associated expenditure reflects bad debt expense, net of recoveries.

Hydro One's Net Bad Debt forecast is based on its Expected Credit Loss (ECL) methodology, which estimates the portion of overdue accounts receivable that is expected to be uncollectible and ultimately written off. The methodology incorporates aging of accounts receivables, probability of default assumptions, historical write-off experience, customer payment behaviour, and forward-looking economic indicators.

3.2.2 EXPENDITURE LEVELS

Collections and Collections Support OM&A expenditures for historical, bridge and test years are provided below in Table 5.

Table 5 - Collections and Collections Support OM&A ($M)[4]

	Historical				Bridge Year	Test Year
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Collections	8.3	8.9	9.1	10.4	10.5	11.3
Field Support	4.1	4.6	6.3	2.8	2.8	6.0
Regulatory Compliance (LEAP)	2.3	2.8	3.5	2.2	2.3	2.7
Net Bad Debt	9.2	15.0	11.2	16.1	15.5	15.4
Total Collections and Collection Support	**24.0**	**31.3**	**30.1**	**31.5**	**31.0**	**35.4**

The 2028 Test Year expenditure for Collections and Collections Support OM&A is $35.4M, an $11.4M increase over 2023 actuals, and a $5.8M increase over the average of the last rate period (2023-2027).

Collections expenditures increase by $3.0M from 2023 ($8.3M) to 2028 ($11.3M). The increase is attributable to the changes in workforce composition as discussed in Section 2.1.2, reflecting a shift in employment status for a portion of existing resources rather than an increase in overall staffing levels.

Field Support expenditures increase by $1.9M from 2023 ($4.1M) to 2028 ($6.0M). In 2025, through an application for redirection, this program received an influx of funding to complete more disconnects and reconnects for collections purposes, leading to a $1.7M increase in spending compared to 2024. In 2028, due to implementation of AMI 2.0, Hydro One will be able to shift costs to remote disconnects and reconnects. While the expenditure forecast is consistent with 2025, this shift will allow more disconnects and reconnects, reducing Net Bad Debt.

Increases in spending in these programs drive a corresponding decrease in Net Bad Debt. Specifically, reductions in Net Bad Debt are driven by increases in Field Support spending.

[4] Figures presented in the table may not sum to the total shown due to rounding.

The Net Bad Debt forecast is stable from 2026-2028 due to expenditures in the Field Support program. Absent these expenditures, it is expected that Net Bad Debt would otherwise continue to increase.

In respect of Net Bad Debt, it was lower in 2023 compared to 2022, primarily due to a reduction in provisioning requirements following the restart of collections and dunning activities and the reversal of a $6.0M manual provision established in 2022 for a population of high-risk customer accounts. The reversal reflected improved collectability and a significant reduction in arrears associated with those accounts, with balances declining from $27.2M to $15.8M.

In 2024, Hydro One completed a comprehensive ECL study to update its Allowance for Doubtful Accounts (AFDA) methodology. The study incorporated both historical write-offs and additional indicators of customer credit risk, including overdue balances, disconnection notices, and First Nation arrears. Economic conditions at the time, including elevated unemployment, declining per-capita GDP, weak household consumption, and persistent post-pandemic customer credit indicators, supported the application of a 30% risk factor adjustment within the ECL framework. Customer arrears metrics remained above pre-pandemic levels, reflecting ongoing affordability pressures and elevated collection risk.

Net Bad Debt remained elevated in 2024 as customer payment pressures continued and overdue accounts receivable balances increased. Collections performance was further challenged by the Canada Post labour disruption, which affected bill delivery and customer payment behaviour, resulting in a significant increase in delinquent accounts and overdue balances. These factors contributed to higher collection risk, despite the implementation of the enhanced ECL methodology.

In 2025, Net Bad Debt improved relative to 2024, reflecting the continued application of the ECL framework and Hydro One’s proactive collections strategy. While the Canada Post labour disruption continued to create pressure on customer payment behaviour and

overdue accounts receivable balances, Hydro One mitigated these impacts through targeted customer outreach, increased collections efforts, payment arrangements, customer assistance programs, and enhanced field support activities. As a result, collections performance improved despite ongoing affordability pressures and elevated arrears levels.

The Net Bad Debt forecast reflects Hydro One's ECL methodology and assumes continued improvement in customer credit quality and collections performance over the forecast period. The forecast is supported by declining overdue accounts receivable balances, gradual improvements in AFDA ratios, and decreasing write-offs as aged arrears are reduced. These improvements are expected to be driven by operational efficiencies, enhanced collections activities, continued customer outreach and assistance programs, and the benefits of AMI 2.0 capabilities, which will improve collections effectiveness and support earlier intervention on delinquent accounts.

Regulatory Compliance expenditures have remained relatively consistent from 2023 ($2.3M) to 2028 ($2.7M) at a compound annual growth rate of 3%.

The overall volume and effectiveness of the Collections and Collections Support program are influenced by several external and operational factors that are largely outside of Hydro One's direct control. These factors include, but are not limited to:

- the level of customer engagement and interaction volumes;
- the proportion of customers eligible for low-income assistance and the availability and scope of financial assistance programs;
- the availability of effective collections tools, including the ability to disconnect service for non-payment in accordance with regulatory requirements;
- customer mobility, including the number of customers closing accounts and receiving final bills;
- prevailing economic conditions;
- industry-wide disruptions, including bankruptcies, labour disruptions; and

- regulatory or policy changes that affect customer behaviour or limit available collections mechanisms.

Hydro One actively monitors these factors and adapts its strategies to mitigate bad debt exposure and minimize impacts on ratepayers.

The proposed funding supports the effective management of accounts receivable, recovery of distribution revenues and other applicable rates and charges, and containment of bad debt costs, while allowing Hydro One to continue providing customers with flexible and meaningful payment options and financial assistance. It also supports Hydro One's response to evolving customer needs, public policy objectives, and ongoing improvements to business processes and technology.

Without the proposed funding, Hydro One would face increased financial, operational, and customer service risks, including:

- Higher volumes and balances of unpaid accounts, placing upward pressure on rates for all customers;
- Reduced capacity to offer flexible, individualized arrears payment arrangements;
- Constrained ability to develop and deploy innovative service offerings, including enhanced self-service payment options;
- Diminished effectiveness in developing, delivering, and communicating financial assistance programs, potentially resulting in increased customer financial hardship, higher disconnection rates, and reduced customer satisfaction; and
- Limited flexibility to adapt collections tools and practices in response to changing customer needs and behaviours.

Overall, the forecast demonstrates a strengthening credit and collections profile, with declining arrears and improved bad debt outcomes driven primarily by AMI 2.0 implementation and continued optimization of collections processes.

3.3 THIRD PARTY SUPPORT

3.3.1 PROGRAM INTRODUCTION

The Third Party Support function supports the procurement of third-party services essential to Customer Care operations including postage, services for paper, electronic billing and communication. The funding also supports the continued use of third party collection agencies to assist managing accounts receivable balances, maximizing recovery of revenue. Leveraging third party collection agencies enables Hydro One to scale collection efforts, reduce bad debt exposure. The majority of these costs are externally driven and established through market-based pricing and competitive procurement processes, with limited opportunity for direct cost control.

3.3.2 EXPENDITURE LEVELS

Third Party Support OM&A expenditures for historical, bridge and test years are provided below in Table 6.

Table 6 - Third Party Support OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Third Party Support	8.9	9.4	9.5	10.9	12.2	13.5

The 2028 Test Year expenditure for Third Party Support OM&A is $13.5M, a $4.6M increase over 2023 actuals, and a $3.3M increase over the average of the last rate period (2023-2027).

From 2023 to 2025, actual spend increased from $8.9M to $9.5M. The increase was primarily driven by higher Canada Post postage fees and increases in other vendor charges associated with collection and payment processing activities. The 2026 ($10.9M), 2027 ($12.2M) and 2028 ($13.5M) forecasts are higher than 2025 actuals ($9.5M), reflecting the continued need for paper billing and mailing services, together with anticipated increases in postage fees and vendor pricing. While Hydro One will continue

to pursue paperless billing enrolment and other process improvements to mitigate these pressures, the forecast reflects the portion of expenditures that remains necessary to support required customer communications, billing, payment processing and collections activities.

4.0 SERVICE ENHANCEMENTS

4.1 PROGRAM INTRODUCTION

The Service Enhancements program supports customer communications, customer research, Indigenous engagement, workforce training, and targeted improvements to customer-facing digital service channels. The program funds marketing and customer education initiatives, customer feedback surveys and research memberships, and Contact Centre agent training programs aimed at strengthening customer service capabilities and supporting continuous improvement. It also funds minor enhancements to digital customer self-service tools to improve customer experience. In addition, the program supports early and ongoing engagement with First Nations and Métis communities on current and future projects.

This funding supports the continuation of activities designed to enhance customer service, including:

- developing and delivering customer communications and marketing campaigns to promote awareness of Hydro One's services and customer assistance offerings;
- conducting customer surveys and providing research services to better understand customer needs, expectations, and the key drivers of customer experience, and to identify opportunities for service improvements, with additional support from an experience management software subscription to enable cost-effective in-house digital experience surveys and related research activities;
- supporting workforce training and development initiatives that enhance customer service capabilities, strengthen employee knowledge and skills, and enable customer-facing staff to respond effectively to evolving customer needs;

- implementing minor enhancements to customer-facing digital channels and self-service tools, including the myAccount platform, to improve customer experience; and
- undertaking early engagement with Indigenous communities, including relationship agreements and related funding mechanisms, to support meaningful participation in project matters that may affect their communities.

4.2 EXPENDITURE LEVELS

Service Enhancements OM&A expenditures for historical, bridge and test years are provided below in Table 7.

Table 7 - Service Enhancements OM&A ($M)

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Service Enhancements	7.7	8.1	8.1	8.4	8.1	7.9

The 2028 Test Year expenditure for Service Enhancements OM&A is $7.9M, a $0.2M increase over 2023 actuals, and a $0.2M decrease over the average of the last rate period (2023-2027).

Expenditures remained relatively stable over the 2023 – 2027 period, ranging from $7.7M to $8.4M. Minor year-over-year fluctuations primarily reflect the timing and scope of workforce training initiatives, Indigenous engagement activities, customer research programs, and communications efforts.

The 2028 forecast ($7.9M) remains in line with historical expenditure levels and reflects the continued need to support customer research, engagement, workforce training, and targeted service improvement activities. These activities provide insights into customer needs and expectations, including those of Indigenous communities, support workforce

capability development, inform service enhancements and improvements to customer-facing channels and tools.

Absent this funding, Hydro One would have reduced ability to obtain customer insights necessary to inform service improvements, maintain customer service levels, enhance digital customer service channels, and support effective engagement with Indigenous communities. This could limit Hydro One's ability to respond to evolving customer needs, reduce opportunities for continuous improvement in customer experience, and increase risks to future project planning and engagement activities.

5.0 DER AND CUSTOMER FLEXIBILITY ENABLEMENT

In alignment with various policy instruments including the Minister of Energy's "Energy for Generations" Integrated Energy Plan (IEP) directive, the OEB's Non-Wires Solutions Guidelines, the Electrification and Energy Transition Panel Report (2023), and the IESO's DER Roadmap and Enabling Resource Project (ERP) which considers the role of DER Coordinator for LDCs, Hydro One is planning to invest in DER Customer Flexibility Enablement program.

Hydro One recognizes that customer flexibility and DERs are becoming increasingly valuable system resources. Technologies such as energy-efficient equipment, demand response, battery storage, smart controls, electric vehicles, and distributed generation can provide meaningful flexibility to both customers and the electricity system. When appropriately enabled, these resources can reduce peak demand, defer or avoid traditional wires investments, improve system utilization, and allow customers to manage their electricity costs more effectively.

Developing customer flexibility capabilities today is critical to achieving these outcomes at the lowest long-term cost for customers. Importantly, these investments are fundamentally driven by customer affordability. Customer flexibility creates new opportunities for customers to reduce electricity costs, earn value from existing energy assets, and make informed choices about how they use and manage energy. At a system level, flexibility

can reduce future infrastructure requirements, improve asset utilization, and moderate the long-term cost of serving growing demand. By enabling customers to become active participants in the electricity system rather than solely consumers of electricity, Hydro One can help deliver a more affordable, resilient, and efficient electricity system for all customers.

For these reasons, Hydro One is proposing targeted investments in Electricity Demand Side Management (eDSM), DER customer engagement, and DER market enablement. Together, these initiatives establish the foundation for a more flexible and customer-centric electricity system, while supporting the provincial objectives of affordability, electrification, reliability, and customer choice.

DER and Customer Flexibility Enablement investments produce benefits beyond non-wires solutions in constrained areas. Electricity demand-side management programs reduce customer energy costs. Customer education and DER enablement increase customer awareness and participation in available programs and markets. Enabling DER market participation provides customers with new opportunities to monetize existing assets such as batteries, controllable loads, and distributed generation. These benefits support customer affordability irrespective of whether specific forecasted growth materializes.

The proposed investment is not predicated on a single forecast outcome. Rather, it is a measured investment in foundational capabilities that improve customer affordability, increase system adaptability, and preserve future planning options under a wide range of potential electricity demand scenarios. Given the significant uncertainty associated with electrification and energy transition pathways, Hydro One believes that establishing these capabilities represents a prudent and cost-effective approach consistent with the OEB's objectives of customer protection, economic efficiency, and long-term affordability.

5.1 PROGRAM INTRODUCTION

The DER and Customer Flexibility Enablement program includes value-added services for customers offering energy audits and energy conservation solutions which will continue from the 2023-27 rate period into the 2028-2032 rate period.

In addition to this service, Hydro One will be investing in three net new areas:

i. Flexibility through electricity Demand Side Management (eDSM)
ii. DER customers engagement
iii. Enabling DER electricity market participation

I. FLEXIBILITY THROUGH LOCAL ENERGY EFFICIENCY

The Local Energy Efficiency program focuses on reducing energy consumption and shifting demand to off-peak periods through various measures and incentives. This program is divided into two streams: (i) Stream 1 electricity Demand Side Management (eDSM), which is recoverable by the IESO, and (ii) Local Energy Efficiency programs, funded by Hydro One, with potential for IESO co-funding through Stream 2.

- Stream 1 eDSM programs include a comprehensive portfolio of programs for residential, C&I customers, offering incentives for implementing energy efficiency measures, IESO's demand response initiatives and energy management for Industrial customers.
- Local Energy Efficiency programs will target energy efficiency offerings that provide incentives for energy-saving upgrades. At the outset, this is expected to include a Retrofit Incentive Adder program targeted to C&I customers.

Both streams aim to reduce overall energy consumption, lower peak demand, enhance grid reliability through peak demand savings, and provide energy affordability support for customers.

The Minister of Energy and Electrification recognized the value of LDCs in their customer's eDSM and energy transition journeys in establishing dedicated LDC funding to promote Stream 1 and deliver Stream 2 programs. Hydro One entered into an eDSM Agreement

with IESO's Stream 1 program in 2025, to begin to promote and engage customers on "Save on Energy" Programs, driving higher levels of awareness and participation. Hydro One's customer engagement activities to promote Stream 1 programs are fully recoverable from the IESO and funded by Global Adjustment. As such, Hydro One is not seeking incremental investment in this application related to these activities.

Hydro One also intends to develop local energy efficiency programs as NWS, which are Hydro One led and funded with potential for IESO co-funding in future, to help address distribution system needs. These are expected to include incentive adder programs where Hydro One would offer increased incentives, power factor correction and other energy efficiency offerings for customers located in an area where distribution system needs exist. Hydro One will market Stream 1 and local energy efficiency programs with a particular focus on areas identified for NWS opportunities. By increasing adoption of energy efficiency measures in these areas, the baseline peak demand can be reduced which reduces the amount of peak demand reductions needed from Demand Response, flexible resources and other NWS measures.

As system demand and energy costs rise, investing in these customer programs empowers customers to make smarter choices to manage energy affordability, contribute to grid stability, and support the transition to a more sustainable and resilient energy system.

II. DER CUSTOMER ENGAGEMENT

As Ontario's electricity system increasingly relies on distributed energy resources (DERs) to provide flexibility and capacity, effective customer engagement is foundational to enabling participation in these programs and markets. Value from NWS cannot be realized without informed, prepared, and willing customers who understand how their resources can be enrolled, dispatched, and compensated. In addition, DER customers need to be properly engaged and educated for them to provide services to the IESO's Enabling Resources Program (ERP).

Investment in DER Customer Engagement is therefore critical to supporting customer participation in Hydro One's DER programs, meeting OEB regulatory expectations, and unlocking the full value of DERs for IESO-administered markets. Without deliberate engagement, customer awareness and readiness will remain limiting factors, constraining participation levels and reducing the effectiveness of DERs as planning and operational resources.

This investment is justified on three interconnected grounds:

1. **Regulatory necessity under the OEB's NWS and DER frameworks**
   The OEB's NWS policy direction and DER connection expectations increasingly assume that customers and aggregators can participate in flexibility- and capacity-based solutions as alternatives to traditional wires investments. Proactive customer engagement is necessary to ensure broad, equitable participation, transparent access to programs, and the practical feasibility of DER-based capacity solutions across Hydro One's service territory.

2. **Operational and system-planning necessity**
   Flexibility and capacity programs require DERs that are not only technically connected, but operationally ready and reliably available when called upon. Customer engagement and education are essential to aligning customer capabilities, operating constraints, and expectations with Hydro One's system needs and broader IESO service needs. This ensures that DERs can be planned for and relied upon as credible capacity and flexibility resources at both the bulk and local grid levels.

3. **Customer participation and value realization**
   Customers will only participate in flexibility and capacity programs if they understand the value proposition, operational requirements, and trade-offs involved. Targeted engagement enables customers to make informed choices about enrolling DERs, managing impacts to their operations, and capturing value from participation. Over time, this builds customer confidence, increases participation rates, and strengthens

overall customer engagement with Hydro One as DERs become a more prominent part of the electricity system.

III. ENABLING DER ELECTRICITY MARKET PARTICIPATION

The IESO has been clear that enabling DER participation in Ontario's wholesale electricity markets will require an expanded role for distributors. Through the Enabling Resources Program (ERP) and related engagement, the IESO has identified LDCs as critical facilitators of wholesale market participation for their customers, often described as the role of "DER coordinator" or market facilitator. Fulfilling this role requires changes to distributor operating models to support customer and aggregator participation while ensuring local system reliability and coordination with bulk system needs. To meet this expectation, Hydro One must invest in foundational capabilities that enable wholesale market facilitation for DER customers.

At the same time, the OEB has directed distributors to evaluate and pursue NWS where they provide net benefits. Increased participation of DERs in wholesale markets can expand the pool of resources available to support NWS, creating additional opportunities to address local distribution system needs through non-wires alternatives. This enables greater coordination between wholesale market participation and distribution system planning, allowing DERs to deliver value to both the bulk and local electricity systems while maintaining safety, reliability, and planning efficiency.

The participation of DER customers in electricity markets increases electricity affordability and empowers customers to play an active role in supporting system needs. Hence, Hydro One is planning to invest in developing these capabilities to procure and coordinate DER provided flexibility and capacity from residential, commercial, and industrial customers for both bulk and local system needs. The technology systems required to manage the market, and to plan, forecast, and operate DERs are described in DSP Section 3.11 D-SS-09 Intelligent Grid Platform.

These investments are necessary to:

- Enable Hydro One to fulfill the IESO envisioned role of DER coordinator under its ERP development;
- Support effective coordination between wholesale market participation and local system constraints; and
- Enable the practical procurement of DER based flexibility and capacity as NWS, consistent with OEB direction.
- Co-develop the design and implementation of shared protocols and procedures between the IESO and Hydro One for coordinated real-time operation of DERs for bulk and local needs.

By establishing these foundational capabilities, Hydro One positions itself as a critical partner in Ontario's DER goals while creating a scalable pathway to support customer participation in flexibility and capacity markets. Enabling DER participation through coordinated wholesale facilitation and local flexibility capabilities supports system efficiency, electricity affordability, and customer empowerment as DERs become an increasingly important component of Ontario's electricity system.

5.2 EXPENDITURE LEVELS

DER and Customer Flexibility Enablement OM&A expenditures for historical, bridge and test years are provided below in Table 8.

Table 8 - DER and Customer Flexibility Enablement OM&A ($M)[5]

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Value-added services	0.3	1.1	0.4	0.7	0.7	0.8
Flexibility through Energy Efficiency	0.9	0.8	0.8	0.0	2.3	7.0
DER Customer Engagement	0.0	0.0	0.0	0.0	0.0	1.0
Enabling DER electricity market participation	0.0	0.0	0.0	0.0	0.0	3.2
Total DER and Customer Flexibility Enablement	**1.2**	**1.9**	**1.1**	**0.7**	**3.0**	**12.0**

The 2028 Test Year expenditure for DER and Customer Flexibility Enablement OM&A is $12.0M, a $10.7M increase over 2023 actuals, and a $10.4M increase over the average of the last rate period (2023-2027).

The increase in expenditures is primarily driven by the new OM&A programs planned for flexibility through electricity demand side management, for DER customers engagement, and for enabling DER electricity market participation.

Expenditures from 2023 ($1.2M) to 2027 ($3.0M) include resource costs for the Conservation & Demand Management (CDM), residential demand response program, and other customer initiatives. No costs for supporting IESO programs funded under the eDSM Framework are included in revenue requirement. Reductions in actual expenditures in 2025 ($1.1M) and forecast expenditures in 2026 ($0.7M) reflect recovery from the IESO.

In 2028, the expenditure forecast ($12.0M) is $9.0M higher than the 2027 bridge year ($3.0M), reflecting the introduction of the Local Energy Efficiency and DER programs. Of the $9.0M increase, approximately $3.0M is attributable to the additional labour costs required to establish capabilities, processes and change management activities

[5] Figures presented in the table may not sum to the total shown due to rounding.

necessary to support the delivery activities of these new programs. Further details regarding the 2028 expenditures for these programs are provided below.

Local Energy Efficiency

The local energy efficiency budget was developed with an aim to achieve a total of 36 MW of incremental peak demand savings by 2032. In all, approximately 90% of the proposed budget is estimated to be spent on customer incentives. The remaining 10% of budget would be spent on administrative items including LDC labour, third party support, marketing, overhead and program evaluation. The Retrofit Incentive Adder was selected for its relatively high incentive to administration ratio, as existing administrative infrastructure can be leveraged. As future opportunities are identified, net-new programs which are unable to leverage an existing program administration structure may require a higher share of program expenditures for administration.

In 2028, the total local energy efficiency programs are estimated to deliver 5 MW of peak demand savings at a total cost of $7.0M, of which $5.6M would be customer incentives. The remaining $1.4M[6] would be spent on administrative costs, including internal labour ($500k), third party support services such as technical review ($500k), marketing ($250k), overhead ($100k) and program evaluation ($50k). Peak demand savings achieved through customer participation in these areas will contribute to the overall peak demand reduction targets for these assets. A larger portion of the local energy efficiency budget will be directed to broader regions of Hydro One's service territory where significant load growth has been forecasted. This investment enables Hydro One to build longer-term customer flexibility to support growth, provide customer affordability solutions and enable Hydro One to more quickly deploy energy efficiency solutions when and where system needs emerge.

[6] The higher administrative share in 2028 reflects the initial program costs. The administrative cost is expected to be on average 10% of the total budget over the 2028–2032 planning period.

DER Programs

In 2028, Hydro One will spend $1M in DER customer engagement activities designed to improve customer awareness, readiness and participation in DER programs and electricity market opportunities:

- Approximately $300k will support the development of a customer engagement strategy focused on DER adoption, including defining priority customer segments and engagement approaches;
- Approximately $100k will be used to design and build a digital platform to provide information, education, and onboarding support for customers interested in DER participation.
- Approximately $300k will be used to deliver structured educational initiatives, establish a robust DER engagement forum, and conduct targeted readiness outreach to DER owners, aggregators, businesses with DERs, and municipalities and Indigenous communities.
- Approximately $300k will be spent on labour to support these initiatives.

These activities will prepare customers to participate in Hydro One's DER programs, support long term system planning, and enable sustained customer participation as reliance on DER-provided capacity continues to grow.

In 2028, Hydro One will also spend $3.2M to establish the capabilities required to facilitate DER participation in wholesale electricity markets. As the market facilitator role is new to Hydro One and the broader industry including the IESO, approximately $2.2M will be spent on labour to define and implement a DER coordinator function in collaboration with the IESO and cross-functional staff, develop the processes and systems to coordinate DER participation, and integrate these new functions into planning, operations, and customer-facing workflows through targeted change management. An additional $1.0M will support the development of the operating model, organizational design, solution architecture, and implementation documentation. Without these operating model changes, Hydro One would be unable to effectively support customer participation in wholesale flexibility and capacity markets as envisioned by the IESO.

6.0 DISTRIBUTION CUSTOMER CARE OM&A COST PER CUSTOMER

Hydro One is striving to respond to our customers' desire for increased customer service while maintaining or reducing Customer Care OM&A expenditure per customer in the test year and over the term of the plan period. Hydro One's performance against this metric from 2023 to 2028 is set out in Table 9 below.

Table 9 - Customer Care OM&A Allocated to Distribution Cost per Customer

Customer Service	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total OM&A ($M)	$94.8	$106.7	$102.1	$115.9	$120.0	$139.6
Number of Customers (Million)	1.49	1.51	1.52	1.47	1.48	1.49
Customer Care OM&A Cost per Customer	**$64**	**$71**	**$67**	**$79**	**$81**	**$94**

The 2028 forecast Distribution customer care OM&A cost per Distribution customer is $94, a $30 increase over 2023 actuals, and a $22 increase over the average of the last rate period (2023-2027). The compound annual growth rate is at 7%, which is slightly higher than OEB inflation factor less the applicable stretch factor. This reflects the above-market cost increases Hydro One has experienced, as described in SPF Section 1.8, indicating that external cost pressures are increasing at a rate that exceeds general inflation. The increase also reflects the need to respond to growing customer expectations, increasing service complexity, and evolving regulatory and system requirements, while continuing to provide customers with reliable service, affordability support, and opportunities to participate in emerging energy and flexibility programs.

DISTRIBUTION O&M WORK EXECUTION STRATEGY

1.0 INTRODUCTION

This Exhibit outlines how Hydro One can efficiently deliver a large and complex distribution Operations and Maintenance work program within approved expenditure levels.

The distribution maintenance portfolio consists of discrete planned and demand programs within the Forestry, Lines, and Stations lines of business. The majority of Hydro One's distribution maintenance portfolio is comprised of planned work. Planned maintenance programs are driven by the need for Hydro One to safely and cost effectively manage reliability, sustain assets over the long term and comply with regulations. Demand maintenance programs are driven by customers who are connected to Hydro One's distribution network, unplanned internal requests and trouble calls related to equipment failures.

To succeed in its variable and complex operating environment, Hydro One employs a flexible process to plan, execute and as needed, reprioritize and transition between planned and demand maintenance work. Planning, execution and reprioritization also involves balancing priorities between capital and maintenance activities as discussed in DSP Section 3.10 Distribution Capital Work Execution Strategy.

This Exhibit discusses the methodologies that Hydro One uses to effectively plan and execute distribution maintenance work within the distribution Forestry, Lines and Stations lines of business. The subsequent sections discuss how distribution Forestry, Lines and Stations perform effective oversight and governance of its maintenance portfolios, details the primary factors impacting work execution, and outlines the resourcing strategy and safety culture. Finally, the Exhibit discusses distribution Forestry, Lines and Stations' continuous improvement efforts which are expected to improve the execution of the maintenance portfolio through the 2028-2032 planning period.

2.0 PROGRAM DELIVERY METHODOLOGIES

This section details the methodologies used by Hydro One to execute its distribution Forestry, Lines and Stations maintenance portfolios. These maintenance portfolios of work consist of both planned and demand programs. Planned and demand maintenance work represent approximately 60% and 40% of Distribution's maintenance expenditures, respectively.

Hydro One uses a formal work acceptance and release process for both planned and demand distribution maintenance work programs. The workflow process attempts to minimize impacts to planned programs resulting from the unpredictable nature of demand work.

Hydro One's planning, monitoring, and reprioritization process is a cross-functional process as discussed in SPF Section 1.7, which combines asset management and investment planning processes to identify, select, prioritize, optimize, and pace investments over the planning period. Asset condition data, regulatory requirements and reliability metrics drive initial prioritization, while real-time operational events and resource constraints inform adjustments. All changes during execution undergo risk assessment and budget validation to maintain reliability, safety, and cost-effectiveness. This structured approach ensures that preventive maintenance remains aligned with system needs and regulatory obligations, even in a dynamic operating environment.

2.1 PLANNED PROGRAM METHODOLOGIES

Distribution planned maintenance work is executed using a programmatic methodology. The programs are driven by more predictable factors including the need for Hydro One to safely and cost effectively manage reliability, sustain assets over the long term, and remain compliant with regulatory requirements.

2.1.1 FORESTRY PLANNED PROGRAM METHODOLOGY

Most of Forestry's planned work consists of the Optimal Cycle Protocol (OCP) line clearing and brush maintenance programs. Planned work also includes the safety patrol and test

and treat programs to inspect poles within regulatory timeframes and test for quality, along with applying herbicide to distribution stations. In addition, Forestry's Quality Assurance and Quality Control (QA/QC) program is in place to measure adherence to its vegetation management program and analyze long-term impacts of program investments through work quality assessments, audits, outage investigations and innovation and program development initiatives.

Forestry's planned maintenance methodology begins when a scope of work is issued from Planning. Planning assesses data to identify high risk feeders or feeder sections requiring inspection. Based on this information, Forestry Work Management schedules Technicians to attend the site to inspect feeders, and identify brushing, tree trimming and removal work that will be required. In some cases, inspection work may be completed through remote sensing technology.

Once the inspection work is complete, Planning reviews the defect inventory on a quarterly basis and selects high risk to safety and reliability feeder sections that need to be addressed by execution crews. The Forestry Work Management Planning team then becomes involved – the planning process accounts for several factors, including the time required to contact landowners who will be impacted by the execution work to notify them, seasonality, and regulatory requirements including notifying the public of herbicide spraying, municipal requirements and the half-load season.[1] Seasonality is key for certain planned vegetation work, such as brush control, because it needs to be executed once snow is gone to ensure roots are accessible and effectively addressed. This is true regardless of vegetation treatment. As a result, this scope is typically executed between spring and fall.

Once all permits and obligations are satisfied, the work is geographically bundled and scheduled to Forestry crews for execution. This step will identify any available execution

[1] The half-load season means the period from approximately March to May when thawing conditions result in vehicle weight restrictions under the *Highway Traffic Act* to protect certain roads and highways.

efficiencies by scheduling maintenance work within proximity to other planned and demand work (e.g. pole testing and treating, pole replacement, capital projects, transmission and customer request vegetation management programs), to minimize travel and costs for temporary work headquarters. Upon completion of the work in the field, Forestry Work Management teams ensure the work orders are reviewed for accuracy and are closed and that statistical key figures to track unit accomplishments are claimed.

At an execution level in Forestry, decisions to shift priorities at an operational level are at times required to meet customer request and off-cycle work impactive to public safety and/or reliability in a timely manner while considering cost constraints and opportunities for scheduling efficiencies.

2.1.2 LINES AND STATIONS PLANNED PROGRAM METHODOLOGY

Lines and Stations both follow the same planned maintenance work execution methodology. Planned maintenance programs within distribution Lines include programs such as Defect Correction, Distribution Lines Underground Patrols, and Distribution Lines Submarine Cable Patrols. Planned maintenance work within distribution Stations includes activities performed annually to maximize equipment performance, increase the lifespan of assets, and maintain reliability. Examples include Preventative and Corrective Recloser Maintenance, Stations Inspections, Transformer Diagnostics, Switch Maintenance, Oil Sampling and Batteries Maintenance & Inspection.

The Lines/Stations planned program methodology begins when a scope of work is issued annually from Planning to Distribution Work Management. The patrol scope of work identifies specific units to be patrolled within the cycle, and the defect correction scope identifies the number of units to be completed based on priority ranking of the defects. As discussed in SPF Section 1.7, work is planned by Planning to address asset condition and anticipated system needs using a risk-based approach. The Work Management teams within Distribution including Program and Project Managers, as well as the execution teams, are leveraged as stakeholders by Planning during scope development. These stakeholders play a key role in providing cost estimates and construction execution

considerations. Once the scope of work is developed, and the work is released to Distribution Work Management, planned maintenance programs can begin to be planned.

The Field Business Centres (FBC) within the Distribution Work Management teams are responsible for the planning and scheduling of work for the execution resources. The FBCs review the high-level requirements and determine the most efficient way to plan and schedule the work programs across the respective regions. Technology such as Geographic Information System (GIS) mapping in the upfront planning process enables improved cross-program planning and execution efficiencies. This geographical map enables the FBC to bundle the work into execution packages. These packages take into consideration the coordination of capital and maintenance work, optimization of the work for outage coordination to reduce the impact on customers and SAIDI, and the optimal execution timing based on site conditions.

Once the work has been geographically mapped, the FBC coordinates with technical and execution resources to ensure any required pre-construction obligations are met, required material is ordered and equipment and fleet requirements are secured. After the pre-construction obligations are coordinated, the work is completed in the field by the execution resources. Upon completion of the work in the field, the FBC close work orders and input data which is used to inform future forecasting and program performance.

2.2 DEMAND PROGRAM METHODOLOGIES

Demand programs are also executed using a programmatic methodology. The programs are driven by inherently unpredictable factors including distribution customer requests, internal unplanned work and trouble calls related to equipment failures.

The unpredictable nature of demand maintenance work can result in actual work volumes deviating from program forecasts. This reality requires Distribution to have execution methodologies in place (as described below) that allow for work reprioritization across its entire maintenance portfolio and to accommodate the associated changes to resourcing and other execution factors.

Maintenance demand programs, like capital demand programs, are forecasted based on a variety of factors including historical trends, scope changes and external factors that may impact demand. On a monthly basis, Program Managers review how the program actuals are trending to budget for both dollars and units and make any forecast adjustment recommendations. This information allows Planning to evaluate reprioritizing planned work as per the investment planning process described in SPF Section 1.7, and ensures Distribution can meet customer commitments and delivers safe and reliable electricity by correcting equipment failures.

2.2.1 FORESTRY DEMAND PROGRAM METHODOLOGY

Trouble Calls are the main scope of Forestry's demand maintenance activities. Weather events often result in tree-related incidents that require the expertise of Forestry crews to clear downed trees and other unwanted vegetation. Forestry's demand maintenance portfolio also includes the Public Safety and Reliability program, which addresses various internal and external requests that require immediate action before the next regular maintenance cycle.

Forestry demand work is either customer-initiated or initiated internally. Customer inquiries are assessed by Support Clerks and Field Technicians to ensure they meet requirements for Hydro One to perform work execution (e.g. ensure vegetation proximity to conductors, confirm requestor owns the property) and confirm whether crews are not already scheduled to attend the location to complete planned work, and if they are, bundle the request with other planned work for efficiencies. Demand work initiated internally is typically requested by the Field when they discover access, safety or reliability concerns. In these scenarios, requests are submitted to the Forestry Work Management department for assessment and approval to proceed with execution, often through consultation with Planning.

Once a demand work request is approved, the FBC will plan and schedule the Forestry crews to attend the site to ensure all hazards are addressed and customer satisfaction is maintained. When deemed appropriate, a Field Technician will be engaged to attend the

site and assess the request. If deemed acceptable for execution, a crew will be scheduled by the FBC to complete the execution work. During the planning of demand work, time is allocated to coordinate with other capital or maintenance work to allow for the bundling of Forestry customer requests with Forestry planned maintenance work. This results in efficiencies regarding mobilization and demobilization. During planning, optimal site conditions must also be considered. For example, scheduling work during frozen conditions to avoid the challenges of working in a swamp.

Once demand maintenance work is planned, pre-construction obligations such as obtaining regulatory permits are completed and resources are secured, the design/inspection and/or field execution begins. Crews are mobilized to site to complete the work. Upon completion of the work in the field, the FBC proceeds to ensure work orders are reviewed for accuracy and closed, and key statistical figures are claimed to track unit accomplishments.

2.2.2 LINES DEMAND PROGRAM METHODOLOGY

The main scope of Lines demand maintenance work is Trouble Calls. These trouble calls are driven by weather events or equipment failures where there is a need to restore customer's power. This includes the locating, assessment, and restoration of these power outages, as well as the resolution of immediate safety issues. Response to trouble calls is initiated by the Integrated System Operating Center (ISOC) which dispatches assigned trouble crews.

Lines demand maintenance also includes addressing various requests directly from customers, contractors, or the Electrical Safety Authority. Examples include disconnect and reconnects (so work can be safely performed near electrical infrastructure) and requests for unscheduled meter reads (which involve move-in, move-out or priority reads). These requests also have specific Service Quality Indicator measures to ensure customer inquiries are addressed in a timely manner and appointment commitments are upheld as described in Exhibit A-05-01. Adherence to the standards requires the ability to adjust priorities and execution crews accordingly.

For Distribution Lines demand work that is requested by a customer, the program delivery process begins when the FBC reviews the customer's request for completeness. Once reviewed, the FBC can start to plan the work. The FBC identifies available resources to complete the field execution. If local execution resources are not available, resources within the region or across the province are sourced. If resources across the region or province are not available, alternative resources will be leveraged such as contractors, or work will be reprioritized to ensure the demand work is completed, and customer commitments are met.

Once execution resources are secured, bundling opportunities are optimized to minimize reliability impacts and ensure efficient use of crews. Crews are then mobilized to the site to complete the work. Upon field completion, the FBC closes work orders and inputs data which is used to inform future forecasting and program performance.

2.2.3 STATIONS DEMAND PROGRAM METHODOLOGY

Stations demand maintenance work includes trouble call response and corrective maintenance of distribution equipment at stations. Trouble calls are generated by system events, alarms, or equipment operations requiring attention and staff deployment. These situations may require urgent corrective maintenance and repairs to ensure system reliability, safety of workers and the public, and to maintain the health of power system equipment. Corrective maintenance may also be performed on station assets because of inspection findings, equipment operations, or asset health analytics. Corrective maintenance is prioritized using a robust methodology which identifies and quantifies risks to reliability, health and safety, and to the environment.

For demand programs that are initiated by equipment failures, the defect is identified and field staff create a notification with priority and repair timelines. The work centre validates priority, estimates repair costs, and the Planning Scheduling Technician issues a work order. Complex defects may involve other lines of business such as distribution Lines or Engineering. Field crews are responsible for accurately assigning priority (Emergent, High, Medium, Low).

2.3 EXECUTION STRATEGY

Hydro One's distribution maintenance strategy requires coordinated planning and execution. This coordinated approach allows the organization to remain focused on its commitment to safety and efficiency. Detailed job planning and frequent communication between crew members and supervisors is emphasized for incident prevention and operational efficiency. Ensuring that frontline distribution workers and supervisors are well informed of potential risks and are actively engaged in safe work planning helps improve workplace health and safety, optimize resource deployment, and minimize execution delays where possible. Focusing on upfront strategic planning and scheduling also improves efficiency. Scope bundling by geographic area is a key driver of execution efficiency, as described above.

2.3.1 EXECUTION FACTORS

Due to the non-discretionary nature of Hydro One's distribution Forestry, Lines and Stations demand maintenance expenditures, emergent demand obligations must generally be prioritized over planned activities to maintain a safe and reliable distribution network and meet customer commitments while ensuring DSC obligations are met. Effectively responding to and executing reprioritized work requires leveraging flexible resource options, implementing governance oversight to monitor risks and opportunities, and continuously seeking opportunities to become more efficient in planning, scheduling and executing reprioritized work within the maintenance programs.

Key factors affecting the execution of planned and demand maintenance include:

- equipment and fleet accessibility;
- outage scheduling; and
- site conditions.

These factors are summarized in the following sub-sections.

2.3.1.1 EQUIPMENT & FLEET ACCESSIBILITY

Identifying necessary equipment and fleet requirements (including associated regular maintenance needs on these assets) to complete various maintenance programs is an important part of distribution's execution planning. During the planning process, the distribution execution resources consider the scope of work, site conditions, access requirements and seasonal factors to secure suitable equipment. As specialized fleet and equipment are often stored in central locations, it is critical that this is factored into the planning process to ensure appropriate coordination and timing.

For example, in some work locations with remote access, Forestry crews access feeders and bring equipment to site by helicopter. Helicopter accessibility must be planned well in advance of execution (typically six to nine months) due to significant fleet demands. To help ensure that specialized equipment is effectively shared across the organization, Hydro One's execution strategy requires that Planning, Distribution Work Management and Fleet Services collaborate on the strategic release of work for execution providing sufficient time to plan and schedule the use of specialized and shared equipment as detailed in GSP Section 4.7, 4.7.2.2.1.

2.3.1.2 OUTAGE SCHEDULING

There are circumstances where maintenance activities require parts of the system to be electrically isolated while work is being performed. Obtaining the required planned outages becomes increasingly difficult as the distribution system grows larger and more complex with the addition of distributed energy resources, smart technology, and supplied load increases. Planned outages are also susceptible to cancellation, which is often due to storm activity, customer demands or system constraints. When planned outages are cancelled, crews must be demobilized and rescheduled for a future date. To mitigate the possibility of increased program costs and limited work accomplishment due to these unforeseen issues, Hydro One has made improvements to planning and bundling of work. For example, the coordination of distribution Lines planned maintenance work during planned Station outages. This allows Distribution to better utilize system outages, plan resources more efficiently, and minimize customer interruptions.

2.3.1.3 SITE CONDITIONS

Varying terrain and seasonal factors across the province impact site conditions, affecting resource needs and equipment and material requirements. The upfront planning process takes into consideration the optimal season to complete work, urban and rural environments, on- and off-road access points, required equipment, and optimal crew size. Site conditions such as soil type, water table, seasonal influences, site disturbance, previous tree failures and future uses for the site are also important considerations that can impact execution strategies. This also includes the use of any herbicide applications which require permission to use, provision of public notice and must account for weather conditions such as wind and rainfall. Finally, the organization leverages environmental conditions to complete work more efficiently. For instance, frozen surface conditions are ideal for access across swamp-like environments and accessing challenging access points can be easier with the use of snowmobiles or off-road equipment.

3.0 PROGRAM OVERSIGHT AND GOVERNANCE

Hydro One maintains oversight over its distribution maintenance work portfolio. Program Managers review the maintenance programs monthly. Similar to the approach applicable to the distribution Capital Programs and Projects portfolio, data is collected and analyzed to inform decision making and forecasts. This routine and ongoing analytical review process enables Distribution to respond to changes that naturally occur within a program lifecycle.

Further, Hydro One employs a reprioritization process to address emerging business needs or to seize opportunities related to the planning and execution of Hydro One's Investment Plan.

4.0 RESOURCING STRATEGY

Distribution's resource strategy is designed to ensure that the organization safely and efficiently delivers its work program within approved expenditure levels, while maintaining service levels for Hydro One customers.

Distribution maintains resource flexibility to efficiently execute the maintenance program by using regular, casual, temporary and contract staff. Regular employees are represented by the Power Workers Union (PWU) and Society of United Professionals (Society) or are non-represented members of management. The resource strategy includes using Hydro One's apprenticeship and training programs where under the guidance of experienced tradespersons and technicians, apprentices develop skills while supporting the maintenance programs. Forestry resources are also shared between the distribution and transmission portfolios leveraging the organization's integrated vegetation strategies to drive efficient planning and work execution.

There are mechanisms in place to minimize resource impacts, which include scheduling of dedicated crews for demand work (such as Trouble Calls) to minimize interruptions to planned work, while maintaining flexibility to address emergent and demand related requests. Dedicated crews are also a strategy that is used for planned program work as well, as some programs such as Distribution Lines Underground Patrols, and Distribution Lines Submarine Cable Patrols have seen higher success in data collection with the use of dedicated crews.

Distribution Stations and Lines do not plan to materially increase their workforce during the planning period to support distribution maintenance work. Forestry plans a minor increase of both regular and casual staff throughout the planning period to execute planned increases to maintenance work volumes. Distribution and Forestry will also pursue third party contractor resources for scalability on an as needed basis which will allow for more flexibility. See Exhibit E-06-02 Workforce Planning for more details of Distribution's resource plans for the 2028-2032 period.

To execute planned maintenance work efficiently, Hydro One Distribution expects to continue strategically balancing staffing levels with the optimized use of overtime (OT) hours to manage demand. Distribution uses OT primarily to meet work requirements that bear a limited degree of predictability. Most OT within distribution is classified as "demand overtime" and is associated with customer demand and emergency work such as Trouble

Calls. This is distinct from “planned overtime” which is the planned scheduling of additional work to meet project or work-related completion schedules while managing the size of the workforce or to perform work outside of regular working hours to minimize outage impact to customers. Demand overtime is necessary to address trouble calls, equipment failure, high priority defect corrections. The Station and Lines work execution plan for the 2028-2032 period assumes OT usage percentages will remain static. These planning assumptions are based on an analysis of types of work that result in overtime hours as well as the average observed over the four-year period prior to the filing of this Application.

Workforce flexibility is a fundamental aspect of distribution’s resource model, while maintaining alignment within the parameters of the applicable collective agreements. Hydro One may utilize contractors when it is recognized that a specific skillset required on a non-regular basis is not available internally or there is an influx of work with a short-term need for additional resource support. Distribution and Forestry have a pool of pre-qualified service providers for certain scopes and uses a competitive Request for Proposal (RFP) process to select the best service provider for specific work assignments. Externally delivered work also adheres to the execution methodologies and contractors are subject to the same governance, tracking and reporting as internally delivered work.

Forestry continues to strengthen relationships with First Nation and Métis communities by exploring opportunities to offer vegetation management and cleanup work within right of way corridors for Hydro One distribution assets on and adjacent to Indigenous lands (e.g. reserve lands). Hydro One has continued to focus on its outsourcing options using Purchased Service Agreements (PSAs) with the Power Workers’ Union, where required, and Request for Proposals (RFPs). By stipulating the business requirements and necessary skillset, Forestry maintains control of the scope of work while driving price transparency and efficiency among proponents. For safety reasons, all work offered to First Nation and Métis communities will be outside of the proximity limits of approach to electrical circuits.

5.0 SAFETY CULTURE

As part of its commitment to becoming the safest and most efficient utility, Hydro One's goal is to reduce and eliminate life-altering injuries. The company's refreshed Health and Safety Plan builds on the strong foundation established through the 2020-2024 Safety Improvement Plan and reflects input from across the organization, including frontline employees, survey results and focus groups. This is supported by the introduction of the Safety Absolutes: a set of guiding principles focused on the most critical hazards that could lead to a life-altering injury.

The company continues to adopt the philosophy that a safe utility is also an efficient utility. Hydro One continues to improve workplace health and safety through its Human Performance program. The overall goal of Human Performance is to ensure that frontline workers and supervisors are well informed of potential risks and are actively engaged in safe work planning. The program recognizes that people make errors and therefore seeks to determine root causes of human errors and then implement tools, processes, and coaching techniques for improvement.

Weekly safety bulletins are distributed and shared with staff at Monday morning tailboard sessions to ensure planning discussions are relevant. Onsite planning meetings are carried out at the start of each day and after breaks to refocus staff and reinforce safe work practices. The use of open-ended questions is encouraged to generate good discussion and to ensure that everyone's viewpoints are heard.

In addition, Hydro One is advancing psychological safety through leadership presentations and programs designed to foster a consistent and supportive environment, promote proactive measures that protect employee wellbeing, and establish clear accountability mechanisms to ensure program effectiveness.

Further details regarding Distribution's safety initiatives and performance are outlined in DSP Section 3.10.

6.0 CONTINUOUS IMPROVEMENT

Distribution continues to implement changes that are expected to improve the execution of its maintenance program. The company seeks to equip its employees with modern tools and opportunities that drive field productivity, improve safety and reliability outcomes, and better integrate the organization.

Forestry has implemented initiatives throughout the current rate period that are expected to drive efficiency. The SAP Service Asset Manager (SSAM) application allows Field staff to identify and complete work requirements from the field by interfacing with the SAP system and allows for reporting and data management tasks by the Work Management teams. SSAM is improved from the previous Work Manager application because it operates on IOS devices and is directly connected to the cloud through mobile carriers to enhance the interactions between field and office workers and improve deployment of resources to safely and efficiently collect, plan and execute work programs. The improvement simultaneously improves reporting and analytics of program accomplishments.

As is further outlined within Exhibit E-03-02, different pilots to remotely sense vegetation for assessment purposes were initiated in 2025, with plans to expand the activities into 2026 and 2027 to benefit strategic planning and risk mitigation efforts. This early work enabled benchmarks of service providers and technologies. The acquired experience enables Hydro One to optimally select the data acquisition alternative (e.g., LiDAR, Satellite imagery, mobile mapping, field-based inspections), based on parameters such as data acquisition costs, time to capture data, level of insights provides by the different alternatives – among others. The integration of remote sensing as part of regular inspection processes is planned to be executed at scale in 2028 for certain feeders. To modernize communications methods with customers, Forestry also piloted electronic notifications to inform customers of upcoming work through use of an auto dialer, with plans to expand its use to other digital communication channels through the 2028-2032 planning period.

Within the distribution Lines organization, productivity improvements have been realized through outsourcing of the PCB Transformer Testing and Inspection program. This initiative resulted in significant savings during the 2022-2025 period and helped put the company in a good position to meet the 2026 PCB removal deadline.

The outsourcing program allowed Hydro One, in working directly with its prequalified contractors to leverage new procedures and technology to efficiently complete PCB transformer inspection and testing. For example, for PCB Transformer inspection, a contractor resource would attend the site location and use digital tools to photograph the transformer and obtain the name plate data. While onsite, the contractor would upload the pictures as well as any additional pertinent information into the mobile application so that it can be validated in real time. Where the results require transformer testing, a contractor crew would be dispatched to efficiently test the transformer using live line methodologies and recording pertinent data into the mobile application onsite. Hydro One plans to continue using this solution for contractor-executed work to achieve efficiencies through the real-time collection and processing of field data.

In addition, Hydro One has focused on improving resource utilization to manage costs within its trouble calls program, which is a major driver of maintenance expenditures. Historically, two distribution Lines staff were dispatched to every trouble call. In addition, most trouble calls occur outside core business hours, which increases program costs. Following extensive consideration and field assessments, Hydro One determined that certain after-hours trouble calls could be safely executed by a single person.

To drive further efficiency, distribution introduced a new approach to reduce the cost per trouble call by adjusting shift schedules, and expanding core business hours coverage. As a result, the average execution time per trouble call fell from 7.9 hours in 2022 to 6.9 hours in 2025, saving approximately one hour of labour and transportation and work equipment costs per call. This model is only used when it does not compromise safety, increase recordable incidents, or materially affect customer satisfaction or restoration times.

7.0 SUMMARY

Distribution Forestry, Lines and Stations follow comprehensive maintenance execution methodologies to deliver a large and complex work program within approved expenditure levels, while maintaining the necessary flexibility to adjust to non-discretionary demand work volumes safely and effectively. The organization remains focused on continuous improvement to drive efficiencies, while leveraging its flexible workforce to support inevitable fluctuations in demand-based work. Maintaining robust oversight over the distribution maintenance portfolio and continuing to identify safe, efficient and cost-effective ways to execute work will remain at the forefront for distribution Forestry, Lines and Stations.

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SUMMARY OF COMMON AND OTHER OM&A

1.0 INTRODUCTION

This Exhibit summarizes Hydro One Common and Other Operations, Maintenance and Administrative (OM&A) expenditures over the 2023 to 2028 period including comparisons between 2023 to 2026,[1] the 2027 bridge year, and the 2028 test year.[2] The Common and Other OM&A expenditures are shared between Hydro One Networks, HOSSM and Hydro One affiliates.

Common and Other OM&A expenditures play a critical role in enabling the safe, reliable and efficient delivery of Hydro One's capital and maintenance work programs and customer services. The Common and Other OM&A plan includes the following services: (i) Common Corporate Function and Services (CCF&S), (ii) Planning, (iii) Digital and Technology Services (DTS) and (iv) Operations. Centralizing these services supports efficient work execution across Hydro One's business segments and its affiliates using the methodology set out in Exhibit E-04-08.

The Common and Other OM&A plan also includes Cost of Sales – External Work, which represents costs directly associated with work performed for regulated and unregulated external revenues across both the Transmission and Distribution businesses, and Other OM&A, which comprises corporate level adjustments and cost recoveries that are direct charges incurred by Hydro One.

As discussed in Exhibits E-02-01 and E-03-01, during 2023 and 2024, Hydro One faced market cost pressures, increasing mandatory compliance requirements, higher demand-driven work volumes, extreme weather, and evolving security needs. These conditions required the company to make business decisions about where and when to spend the overall OM&A funding available for the custom incentive rate-making (IR) term.

[1] Includes actual expenditures for 2023-2025 and forecast expenditures for 2026.
[2] 2029 to 2032 OM&A is established mechanistically, using an index-based approach, in accordance with the Custom IR framework described in Exhibits A-04-01, A-04-02 and A-04-03.

To mitigate the challenges experienced in the early years of the current rate period, Hydro One implemented productivity and cost control measures, including a company-wide cost optimization program, as discussed in SPF Section 1.4.3.2, and reduced or deferred certain planned work where doing so would not create unacceptable near-term reliability, compliance or customer service risk. These measures supported the management of cumulative OM&A expenditures over the five-year rate period.

The 2028 Common and Other OM&A plan establishes the sustainable corporate and operational platform necessary to execute Hydro One's expanded system plans in a more digital, risk-intensive, and highly regulated operating environment, after the temporary reprioritization measures used during the current rate period have reached their practical limit. This represents the level of funding required to support the safe and reliable delivery of Transmission and Distribution services for customers.

1.1 BACKGROUND FOR VARIANCE EXPLANATIONS

Hydro One provides variance explanations relative to the 2023 to 2027 annual average, as this provides a more representative basis for assessing variances relative to the Company's historical OM&A cost base. As discussed in Section 1.0, Hydro One incurred higher costs in 2023 and 2024 to address demand-driven work, market cost pressures, and mandatory requirements. Through productivity initiatives, cost control measures, and the selective deferral or re-pacing of certain planned activities, Hydro One subsequently reduced spending where prudent. The annual average therefore reflects Hydro One's management of OM&A over the full five-year rate period and provides a more appropriate basis for assessing 2028 variances than any individual year.

1.2 COMMON AND OTHER OM&A FORECAST OVERVIEW

The Corporate Common and Other OM&A forecast for the 2028 test year aligns with the needs and drivers identified in the Business Plan (Exhibit A-03-01, Attachment 1). Hydro One's Common and Other OM&A expenditures for the historic, bridge and test years are provided in Table 1 below.

Table 1 - Summary of Total Common and Other OM&A Costs ($M)[3]

Description	Historical					Bridge	Test
	2023	2023	2024	2025	2026	2027	2028
	OEB Approved	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Corporate Functions & Services (CCF&S)		230.3	242.9	237.1	276.6	272.8	303.2
Planning		44.3	47.4	46.6	49.9	51.0	66.9
Digital & Technology Services (DTS)		180.7	164.9	168.7	174.7	184.2	322.4
Operations		90.6	98.1	94.5	107.2	106.4	137.8
Cost of Sales - External Work		14.0	28.0	31.7	14.6	18.7	12.7
Other OM&A		-142.7	-149.9	-186.8	-228.3	-246.3	-291.0
Total[4]	**N/A**	**417.2**	**431.3**	**391.7**	**394.6**	**386.7**	**551.9**

Hydro One is proposing Corporate Common and Other OM&A funding of $551.9M for the 2028 test year, a $147.6M increase above average annual expenditures during the 2023-2027 period. This increase is primarily driven by DTS, CCF&S, Operations, and Planning, as explained in Sections 3.1 and 3.2 and is partially offset by reductions in Other OM&A, as described in Section 2.6, resulting from higher overhead capitalization and lower corporate level adjustments.

The 2028 Common and Other OM&A proposed spending of $551.9M includes $219.1M allocated to Transmission, $271.1M allocated to Distribution and $1.2M allocated to HOSSM. The remaining $60.5M relates to other affiliates and non-regulated segments. Tables 2 through 5 summarize Hydro One's portion of the Common and Other OM&A Costs allocated to Transmission, Distribution, HOSSM, and Affiliate and Non-Regulated Segments over the 2023 to 2028 period, respectively. Costs associated with HOSSM are discussed in Exhibit E-02-06.

[3] Rounded figures within tables may not sum precisely due to rounding.
[4] Total Common and Other OM&A costs include the cost of Common OM&A services provided on a shared basis to Hydro One Transmission, Distribution, HOSSM and other non-regulated segments/affiliates.

Table 2 - Summary of Total Common and Other OM&A Costs Allocated to Transmission ($M)[5]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Corporate Functions & Services (CCF&S)	99.9	102.1	104.5	115.8	113.3	139.0
Planning	26.5	28.3	28.4	33.1	33.3	39.1
Digital & Technology Solutions (DTS)	69.1	63.1	63.8	66.6	72.2	118.4
Operations	49.6	53.9	51.0	57.5	55.8	72.9
Cost of Sales - External Work	8.5	9.9	13.3	10.1	14.0	9.9
Other OM&A	-78.4	-94.9	-112.4	-104.4	-101.3	-160.3
Total	**175.1**	**162.4**	**148.7**	**178.7**	**187.3**	**219.1**

Table 3 - Summary of Total Common and Other OM&A Costs Allocated to Distribution ($M)[5]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Corporate Functions & Services (CCF&S)	97.1	102.0	96.8	113.7	113.0	115.5
Planning	17.7	18.2	17.4	16.0	16.9	19.8
Digital & Technology Solutions (DTS)	109.3	98.5	99.9	105.6	109.7	201.8
Operations	39.2	42.9	42.2	48.5	49.9	62.1
Cost of Sales - External Work	5.5	18.1	18.4	4.5	4.7	2.7
Other OM&A	-68.7	-59.0	-80.7	-123.9	-145.0	-130.7
Total	**200.1**	**220.7**	**193.9**	**164.4**	**149.3**	**271.1**

[5] Rounded figures within tables may not sum precisely due to rounding.

Table 4 - Summary of Total Common and Other OM&A Costs Allocated to HOSSM ($M)[6]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Corporate Functions & Services (CCF&S)	0.6	0.4	0.6	0.7	0.7	0.9
Planning	0.2	0.2	0.1	0.3	0.3	0.1
Digital & Technology Solutions	0.0	0.0	0.0	0.0	0.0	0.0
Operations	0.2	0.3	0.2	0.3	0.3	0.3
Cost of Sales - External Work	0.0	0.0	0.0	0.0	0.0	0.0
Other OM&A	0.0	0.0	0.0	0.0	0.0	0.0
Total	**0.9**	**0.9**	**0.9**	**1.3**	**1.3**	**1.2**

Table 5 - Summary of Total Common and Other OM&A Costs Allocated to Affiliate and Non-Regulated Segments ($M)[6]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Corporate Functions & Services (CCF&S)	32.8	38.4	35.2	46.4	45.8	47.8
Planning	0.0	0.7	0.7	0.5	0.5	8.0
Digital & Technology Solutions	2.3	3.3	5.0	2.5	2.3	2.2
Operations	1.6	1.0	1.1	0.9	0.3	2.5
Cost of Sales - External Work	0.0	0.0	0.0	0.0	0.0	0.0
Other OM&A	4.4	4.0	6.2	0.0	0.0	0.0
Total	**41.0**	**47.4**	**48.2**	**50.3**	**48.9**	**60.5**

[6] Rounded figures within tables may not sum precisely due to rounding.

2.0 DESCRIPTION OF CATEGORIES

This section summarizes the OM&A categories that comprise the Common and Other OM&A. Further detail for each category is provided in the accompanying exhibits identified in Table 6.

Table 6 - Breakdown of Common and Other OM&A Exhibits

Category	Exhibit Reference	Exhibit Title	Witness
CCF&S	E-04-02	Common Corporate Functions and Services and Other OM&A	Anthony Nava
Planning	E-04-03	Planning	Alex Jackson
Digital & Technology Solutions	E-04-04	Digital & Technology Solutions	Kevin Marcotte
Operations	E-04-05	Operations	Lorraine Gray; Kevin Marcotte
Cost of Sales – External Work (Tx)	E-04-06	Cost of Sales – External Work (Transmission)	Scott Vicary; Julie Ricketts Daniel
Cost of Sales – External Work (Dx)	E-04-07	Cost of Sales – External Work (Distribution)	Gianni DiFilippo
Other OM&A	E-04-02	Common Corporate Functions and Services and Other OM&A	Anthony Nava
Cost Allocation Methodology	E-04-08	Common Corporate Costs & Allocation Methodology	Anthony Nava

2.1 COMMON CORPORATE FUNCTIONS AND SERVICES (CCF&S)

CCF&S provide centralized corporate services that support Hydro One's affiliates and business units on a shared basis, enabling consistent service delivery and avoiding duplication of key functions and roles. As described in Exhibit E-04-02, CCF&S includes several program areas that provide the governance, financial stewardship, workforce capability, stakeholder and Indigenous engagement, legal and regulatory support, security, assurance, facilities, real estate and enterprise transformation capabilities required to plan, manage and operate Hydro One's businesses.[7] Together, these CCF&S functions support the corporate infrastructure Hydro One needs to deliver transmission and distribution services safely, reliably, efficiently, and effectively, including maintaining legal and

[7] Corporate Management, Finance, Human Resources, Corporate Affairs, General Counsel, Regulatory Affairs, Security Management, Internal Audit, Facilities and Real Estate

regulatory compliance and ensuring appropriate oversight and governance of the enterprise.

2.2 PLANNING

Planning is responsible for identifying and managing transmission and distribution system planning needs, coordinating customer and stakeholder planning, developing investment strategies and governance, and advancing continuous improvement and industry alignment to support safe, reliable, and compliant system operations. Planning also leads the integrated system planning processes that support Hydro One's annual investment plans and multi-year rate application investment plans as described in SPF Section 1.7. The planning activities are outlined in Exhibit E-04-03.

2.3 DIGITAL AND TECHNOLOGY SOLUTIONS

Digital & Technology Solutions (DTS) manages the enterprise hardware, software, applications, data and voice communications systems, and security services that enable Hydro One's employees and business processes to operate efficiently, effectively, and securely. DTS OM&A expenditures are organized into five program areas, as described in Exhibit E-04-04.[8] Together, these expenditures primarily support Hydro One's IT environment, as well as common communications and security services that support business and operational technology environments. DTS OMA funding supports business continuity and operational resilience by maintaining vendor-supported systems, addressing aging technology and accumulated technical debt, protecting critical systems and data, reducing the risk and impact of technology outages, cyber incidents, and recovery challenges. The funding also enables the technology and data driven delivery of work programs across Hydro One's transmission and distribution systems.

Digital systems are now embedded in Hydro One's day-to-day operations and support essential functions such as customer service and billing, outage and asset management, engineering and work execution, system monitoring, telecommunications, regulatory

[8] Sustainment, Business Telecom, IT Development, Security, Technology Management and Project Controls

reporting, financial management, and security operations. For example, the meter-to-bill process supports the collection of meter data, billing calculations, and bill generation to ensure customers are billed accurately and on time. The continued availability, integrity, recoverability, and security of these systems and their data are therefore essential to reliable utility operations and customer service.

Hydro One's technology landscape is also expanding and becoming more integrated as new systems, cloud-based platforms, connected devices, and data-driven capabilities are introduced. Capital and prepaid investments planned for 2028-2032 will address legacy systems and technical debt, but each system placed into service creates ongoing OM&A obligations for licensing, subscriptions, hosting, vendor support, monitoring, maintenance, cybersecurity management, upgrades, testing, and operational support. As more investments are made towards cloud-based technologies, a greater share of technology expenditures is reflected in OM&A through recurring subscription, licensing, hosting, support, and maintenance costs. These requirements, together with vendor pricing increases, changing licensing and consumption models, growing data volumes, and increasing cyber and physical security demands are driving higher ongoing OM&A needs. The requested funding is necessary to maintain a secure, supportable, recoverable, and resilient technology environment and avoid further accumulation of operational risk. Further details are described in Exhibit E-04-04.

2.4 OPERATIONS

Operations OM&A expenditures support the safe, reliable and efficient day-to-day operation of Hydro One's transmission and distribution systems by funding the people, tools, systems, infrastructure, and safety programs required for 24/7 real-time grid operations, consistent with applicable requirements, including the IESO Market Rules, NERC and NPCC reliability standards, and good utility practice. These systems and tools enable Hydro One to monitor and control transmission and distribution assets, manage customer outage information, coordinate and dispatch crews, plan for and respond to contingencies, schedule planned outages, provide customer notifications, monitor system performance, and integrate smart devices into distribution operations. As described in

Exhibit E-04-05, Operations OM&A expenditures are organized into four program areas[9] to manage increasing operational workload and complexity, support the realization of grid modernization capabilities, support DER integration, and respond to the evolving reliability and resiliency needs and expectations of the customers and communities Hydro One serves.

2.5 COST OF EXTERNAL SALES

Cost of External Sales includes costs directly associated with work performed for regulated and unregulated external revenues across the Transmission and Distribution businesses. For the Transmission business, external work includes station maintenance activities, engineering and construction work, and other competitive services requested by customers. This category also includes costs directly attributable to administering and supporting Hydro One's Secondary Land Use program. For the Distribution business, external work includes costs associated with regulated revenues, such as customer new connections and service upgrades, street light maintenance, and forestry work based on OEB-approved specific service charges. It also includes costs associated with unregulated revenues, such as storm restoration, Hydro One Remotes transport work equipment used for emergency services, and Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) training and development. Details regarding the Transmission and Distribution cost of sales are provided in Exhibit E-04-06 and Exhibit E-04-07, respectively.

2.6 OTHER OM&A

Other OM&A primarily consists of a credit for capitalized overheads, which represents the portion of allocated common corporate and business unit functions and services that support capital work execution. Other OM&A expenses are therefore reduced by these capitalized amounts and may fluctuate from year to year based on the mix of capital and maintenance work completed. Additionally, Other OM&A includes adjustments for the non-service cost component of other post-employment benefits (OPEB), environmental provisions, indirect depreciation, and other costs, which are further described in Exhibit E-04-02, Section 3.0.

[9] Operations, Operations Support, Health, Safety and Environment, DER Technology Sustainment

3.0 COMMON AND OTHER OM&A EXPENDITURES – VARIANCE ANALYSIS

The following sections discuss the key variances and expenditure trends that apply to the Common and Other OM&A programs across the 2023 to 2027 historical and bridge years, and the 2028 test year. As the 2023 OM&A OEB-approved amounts were established at the Transmission and Distribution envelope level, variances between 2023 actuals and 2023 OEB-approved amounts are explained at the envelope levels in Exhibits E-02-01, Section 3.1 (Transmission) and E-03-01, Section 3.1 (Distribution).

3.1 CURRENT RATE PERIOD: 2023 ACTUALS TO 2027 BRIDGE YEAR

As described in Exhibits E-02-01 and E-03-01, Hydro One managed its OM&A expenditures as a five-year funding envelope, balancing the execution of the Transmission and Distribution plans over the rate term against the total OM&A funding available in rates at the envelope level. Over the current 2023-2027 rate period, Total Common and Other OM&A expenditures are expected to decrease modestly, from $417.2M in 2023 to $386.7M in 2027. Since 2023, Hydro One has incurred higher costs to support its growing capital and OM&A work programs. However, these higher costs have been substantially offset by increased overhead capitalization associated with the expanding capital plan, resulting in a 2027 total envelope that is expected to remain relatively stable compared to 2023 levels. This is illustrated in Figure 1 below, which presents Common and Other OM&A expenditures from 2023-2027, broken down by category.

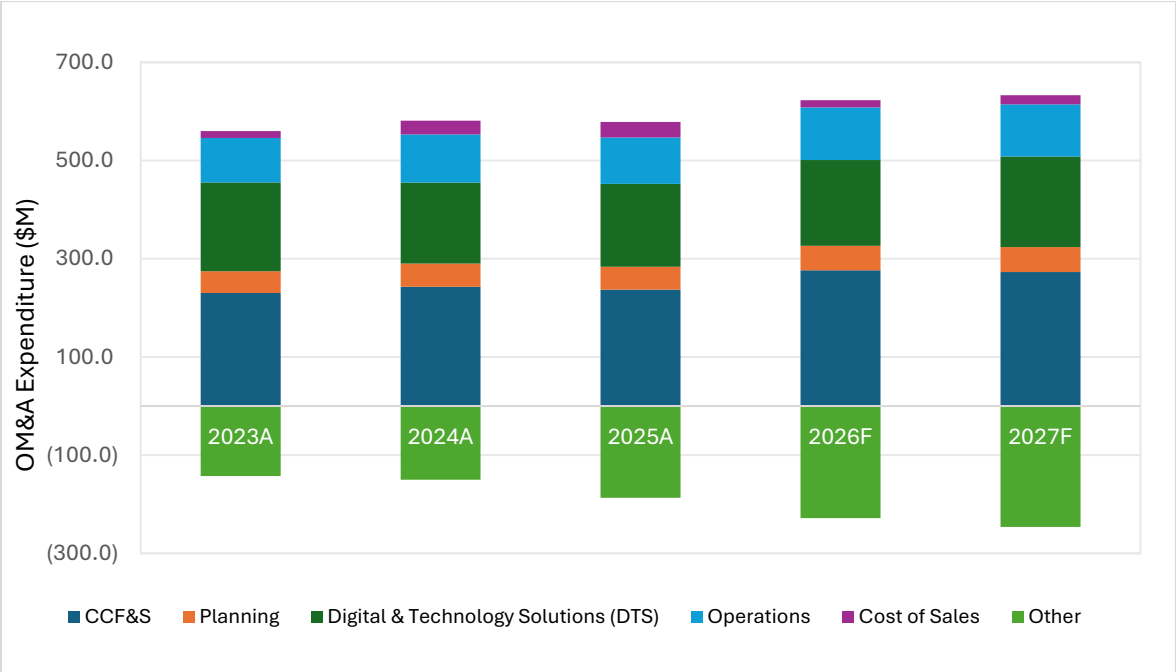

Figure 1: 2023 to 2027 OM&A Expenditures by Major Category of Common and Other OM&A

Over the 2023-2027 period, Hydro One directed Common and Other OM&A funding to the areas of greatest need to support business continuity, maintain compliance, and respond to evolving business and regulatory conditions. These trade-offs are discussed in greater detail below. The following summarizes key trends and expenditure drivers for Hydro One's largest Common and Other OM&A spending categories: CCF&S, DTS and Operations.

- **CCF&S** - Over the 2023-2027 period, CCF&S costs are forecast to increase from $230.3M in 2023 to $272.8M in 2027, reflecting incremental work requirements in Human Resources, Corporate Affairs, General Counsel and Regulatory Affairs. These increases are driven by growth in workforce and work program requirements; expanded customer, stakeholder and Indigenous engagement needs; increased legal, governance and secretariat support; and evolving regulatory and legislative requirements. These increases are largely offset by mitigation measures, including work prioritization in Finance, Internal Audit, and Real Estate and Facilities.

- **DTS** - Over the 2023–2027 period, DTS costs are forecast to increase moderately from $180.7M in 2023 to $184.2M in 2027. In 2023, Hydro One increased OM&A spending to strengthen its ability to monitor, detect and respond to potential vulnerabilities across its IT and OT environments, and to maintain the resilience and security of critical systems that support business and grid operations. Following the completion of these activities, OM&A spending declined to $164.9M in 2024, before gradually increasing through 2027, primarily due to increased adoption of cloud-based technology solutions, the associated subscription costs, and inflation driven increases in vendor pricing, and hardware and memory costs. Hydro One employed cost containment and control strategies to moderate expenditure growth over the 2023-2027 period. As described in Exhibit E-04-04, these strategies included formal processes to optimize third-party contracts, such as early renewal reviews, licence rationalization, vendor consolidation and strategic vendor roadmaps, and the ongoing review of third-party technology expenditures. These strategies helped offset a portion of the underlying technology cost pressures while maintaining the reliability, security and vendor supportability of Hydro One's technology environment.
- **Operations -** Over the 2023–2027 period, Operations costs are forecast to increase from $90.6M in 2023 to $106.4M in 2027. This increase reflects the continued expenditures necessary to maintain Hydro One's core operational capabilities across its transmission and distribution systems, including 24/7 real-time monitoring and control, outage planning and execution, crew coordination, emergency response, customer outage communications, and compliance with applicable reliability and market requirements. These expenditures support Hydro One in managing a more complex operating environment and sustaining the systems, tools and operational support required to maintain safe and reliable service. The forecasted increase through 2027 is driven by the need to sustain existing operational readiness in response to growing distribution demand. This represents a compound annual growth rate of 4%, in line with average OEB inflation over the same period.

3.2 2028 TEST YEAR INCREASES

The 2028 Common and Other OM&A expenditure establishes the sustainable corporate and operational platform necessary to execute Hydro One's expanded system plans in a more digital, risk-intensive, and highly regulated operating environment, after the temporary reprioritization measures used during the current rate period have reached their practical limit.

In the 2028 Test Year, planned expenditures within Common and Other OM&A total $551.9M, which is $147.6M above the 2023 to 2027 annual average. As illustrated in Figure 2 below, the key drivers of this variance are DTS, CCF&S, Operations and Planning OM&A programs. Further details on the 2028 Test Year expenditures for these categories are provided in this section.

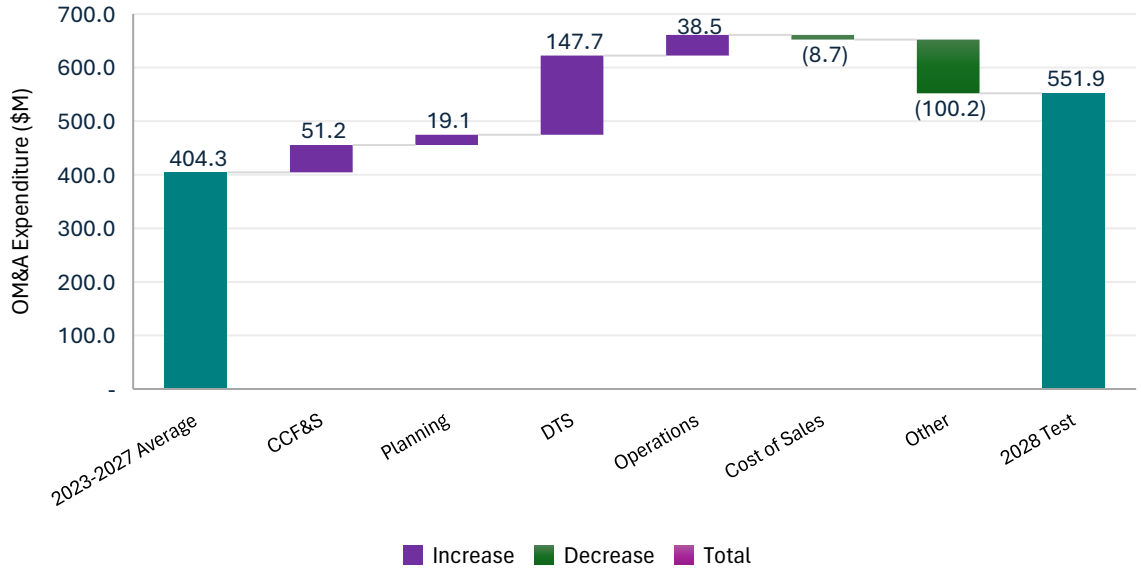

Figure 2: 2028 Increase in Common and Other OM&A relative to the 2023-2027 Average

3.2.1 DTS

Hydro One's Transmission and Distribution businesses rely on technology, telecommunications, security, and technology governance capabilities, to support system operations, asset management, outage response, customer service, and the delivery of an expanding work program. As the scale, complexity, and reliance on these capabilities continue to increase, additional funding is required to sustain and modernize Hydro One's technology environment. This includes maintaining reliable and vendor supported systems across Hydro One's dispersed operating footprint, expanding cyber and physical security capabilities, and strengthening technology management, planning, and project controls.

These requirements are reflected in higher third-party vendor licensing, cloud subscription, and support costs; the realignment of certain OT security sustainment costs; and non-capitalized activities required to implement and adopt new capital and cloud technologies. The increase in 2028 also reflects the costs for DTS cloud implementation and subscription costs that were recorded or forecast through the Incremental Cloud Computing Implementation Costs DVA during the 2023-2027 period (see exhibit G-01-01 for details). Together, these expenditures support business continuity, operational resilience, compliance, secure and reliable system operations, and delivery of Hydro One's expanded transmission and distribution work programs.

Accordingly, Hydro One is proposing $322.4M in DTS expenditures for the 2028 Test Year, a $147.8M increase above average annual expenditures during the 2023-2027 period. The largest drivers of the increase are Sustainment, IT Development, and Security, as follows:

- **Sustainment ($81.4M increase):** The increase is driven primarily by growth in third-party technology contracts and cloud subscription fees as major cloud initiatives transition into steady-state operations and costs previously recorded or forecast through the Incremental Cloud Computing Implementation Costs DVA are reflected in DTS OM&A beginning in 2028. Funding will support recurring licensing, maintenance, and vendor support requirements, including those associated with S/4HANA One-Core and AMI 2.0, while maintaining approximately 600 business

software applications and supporting infrastructure. These activities help maintain service continuity, support field and outage response systems, and reduce operational risk. Further details are provided in Exhibit E-04-04, Section 2.1.

- **IT Development ($27.4M increase):** The increase reflects the OM&A costs required to support a larger capital and cloud implementation portfolio, including application upgrades, infrastructure modernization, business process redesign, training, change management, and data migration activities that cannot be capitalized. The funding also supports lifecycle upgrades, security patching, and decommissioning activities required to maintain vendor support, performance, reliability, and compliance. Further details are provided in Exhibit E-04-04, Section 2.3.
- **Security ($22.3M increase):** Approximately $13M of the increase reflects the realignment of OT security sustainment costs previously recorded under NERC Security into the General Security category. The remaining increase supports expanded cyber and physical security monitoring, additional security tools, labour and external expertise, and enhanced compliance activities associated with evolving NERC CIP requirements. It also responds to a more complex threat environment, including AI-enabled attacks, drone threats, and quantum-related risks, and funds integrated security operations, improved situational awareness, and specialized internal expertise. Further details are provided in Exhibit E-04-04, Section 2.4.

Hydro One is also proposing a DTS Operations Variance Account for both its transmission and distribution businesses to address the risk that third-party cloud subscription and licensing costs may grow faster during 2029–2032 than the OM&A funding provided through the proposed custom incentive rate-setting framework described in Exhibit A-04-01. For details on the DTS Operations Variance Account, refer to Exhibit G-01-03, sections 5.3 and 9.3, and Exhibit E-04-04, Section 1.1.1.

3.2.2 CCF&S

Hydro One's Transmission and Distribution businesses rely on CCF&S to provide enterprise governance, regulatory support, workforce services, corporate infrastructure, and other corporate capabilities necessary to support system operations and deliver expanding capital and maintenance work programs. As the scale of work programs expand, additional funding is required to support growing workforce requirements, enterprise governance, regulatory obligations, and critical corporate infrastructure.[10]

Hydro One is proposing $303.2M in CCF&S expenditures for the 2028 Test Year, representing an increase of $51.3M above average annual expenditures during the 2023-2027 period. The proposed funding will provide the people, tools, systems, and governance required to manage higher work volumes, address additional requirements, and support reliability and customer service.

The increase primarily reflects expenditures in Real Estate and Facilities, Human Resources, Corporate Affairs, and Regulatory Affairs to support evolving business, operational, regulatory, and stakeholder requirements. Real Estate and Facilities is the largest driver, accounting for $16.2M of the total CCF&S increase. This increase is driven by Hydro One's expanding operational footprint, lease renewals, inflationary pressures, and new or expanded facilities required to support workforce growth and the execution of Hydro One's capital and business plans.

Collectively, the proposed CCF&S expenditures support Hydro One's expanded work programs, legal and regulatory obligations, and safe and reliable delivery of transmission and distribution services. Further details are provided in Exhibit E-04-02.

[10] For details on the Transmission, Distribution, and General Plant capital work programs, refer to TSP 2.1, DSP 3.1 and GSP 4.1, respectively. For details on the Transmission and Distribution OM&A work programs, refer to Exhibits E-02-01 and E-03-01, respectively.

3.2.3 OPERATIONS

Hydro One's Transmission and Distribution businesses rely on Operations and Operations Support capabilities to provide real-time system operations, outage coordination, control centre services, operating tools, applications, and technology platforms that support the safe and reliable operation of the electricity system. The Operations program delivers core operational functions, including operations system monitoring and control, outage scheduling and coordination, emergency response coordination, and system performance monitoring. The Operations Support program maintains and enhances the operations technology platforms, integration services, and supporting infrastructure that enable these functions. As Hydro One's capital and work programs continue to expand in scale and complexity, additional funding is required to support higher operating workloads, outage coordination requirements, new technology capabilities, and growing compliance obligations.

Accordingly, Hydro One is proposing $137.8M in Operations expenditures for the 2028 Test Year, an increase of $38.4M above average annual expenditures during the 2023-2027 period. The increase is primarily driven by Operations and Operations Support expenditures. Operations expenditures are increasing by $21.0M, reflecting higher real-time operating workload, outage coordination, and control-room requirements associated with the growth of Hydro One's capital and maintenance work programs. Operations Support expenditures are increasing by $14.5M to sustain operating tools, integration platforms, Oracle infrastructure, operating applications and grid technology project management.

Collectively, these expenditures support the reliable operation of Hydro One's transmission and distribution systems and the effective delivery of its expanding capital and maintenance work programs. Further details on Operations OM&A are provided in E-04-05.

3.2.4 PLANNING

Planning supports Hydro One's transmission and distribution businesses by assessing future system needs and identifying the investments required to meet Ontario's growing demand, maintain the grid through asset renewal and sustainment, improve distribution reliability and resiliency, support grid modernization and maintain compliance with regulatory requirements. While Planning absorbed increasing work volumes during the 2023-2027 period through efficiencies and reprioritization, the scale, complexity, and increasingly mandatory nature of system planning requirements now exceed what can reasonably be managed through further efficiency efforts alone.

The proposed 2028 Test Year spending is $66.9M, representing a $19.1M increase above average annual expenditures during the 2023-2027 period. The increase reflects a larger and more complex planning workload driven by significant growth in transmission and distribution investment programs, customer connections, regional and bulk system planning activities, and asset renewal requirements. Hydro One is forecasting transmission System Access investments at approximately three times the level of the prior rate period, along with significant growth in Transmission Regional and Bulk Plan investments, resulting in a more than six-fold increase in investments driven by Transmission Regional Planning and Bulk Planning compared to the prior rate period.

Across transmission and distribution, Planning will undertake a greater volume of specialized studies and advanced modelling and analytics to support system planning and compliance with new and evolving regulatory expectations, including the OEB's Vulnerability Assessment and System Hardening requirements (EB-2024-0199), Non-Wires Solutions requirements (EB-2024-0118) and Reliability and Power Quality requirements (EB-2021-0307). The proposed plan will establish the planning capabilities required to support Hydro One's expanding investment plans, respond to evolving regulatory requirements, and enable the next phase of system growth and modernization.

4.0 REASONABLENESS OF PROPOSED EXPENDITURES

Hydro One's proposed Common and Other OM&A expenditures are reasonable because they are grounded in integrated investment planning and business planning processes, informed by customer and system needs, and paced to balance operational requirements with customer rate impacts. The plan supports the continued safe and reliable operation of the Transmission and Distribution system while addressing the accumulated impacts of work reprioritization, cost pressures, evolving customer expectations, cyber and physical security requirements, and sector transformation.

The 2028 Test Year plan establishes a sustainable operating baseline for the next rate period. It provides the corporate, technology, planning, and operational capabilities required to deliver Hydro One's expanded capital and maintenance programs and maintain safe, reliable, and resilient service for customers.

Hydro One's 2028 Common and Other OM&A plan of $551.9M was developed through a bottom-up planning process grounded in the operational requirements to support and execute Hydro One's work programs. It reflects customer needs and preferences, promotes the OEB's Renewed Regulatory Framework (RRF) outcomes, and is supported by Hydro One's demonstrated capability to effectively prioritize and deliver OM&A programs. The planning context, customer engagement, alignment with RRF outcomes, and Hydro One's ability to execute the plan are described in the subsections below.

The reasonableness of the proposed expenditures is also supported by an external benchmarking analysis of Common Corporate Costs, which assessed the efficiency and effectiveness of Hydro One's centralized corporate functions. Further details on the analysis are provided in Exhibit E-04-02, and the study is included as Attachment 1.

4.1 PLANNING CONTEXT

As described in SPF Section 1.7, Hydro One's 2028 Common and Other OM&A plan was developed on a bottom-up basis, informed by asset condition, customer needs, and the operational requirements of the Transmission and Distribution businesses. It supports the

capital investments identified in the Transmission System Plan (TSP), the Distribution System Plan (DSP) and the General System Plan (GSP), as well as the Transmission and Distribution OM&A work programs.

The plan was developed through a risk assessment of candidate maintenance and operational activities based on safety, reliability and environmental risk, while also considering customer input, management insight, and the company's strategic priorities and objectives. Common and Other OM&A activities such as investment planning, technology sustainment and development, system operations and outage coordination, health and safety programs, corporate governance, regulatory compliance, security management, and facilities management provide the capabilities required to execute and sustain work programs across all business segments and help ensure customers realize the benefits of Hydro One's investment plan.

4.2 CUSTOMER ENGAGEMENT

As detailed in SPF Sections 1.6 and 1.7, feedback from customer engagement directly informed the development of the investment plan. The customer priorities identified through the Innovative Research Group (IRG) Study, including system reliability, asset stewardship, service quality, and operational efficiency, are outcomes that depend on the shared corporate functions and services funded through Common and Other OM&A.

The IRG Study found strong support across customer types for spending at or above Hydro One's draft investment plans. Customers supported expenditures related to system reliability, managing severe weather, targeted reliability improvements, asset renewal, facilities and information technology. Common and Other OM&A supports these priorities through system operations, planning, technology, security, health and safety and facilities capabilities.

4.3 ALIGNMENT WITH RRF OUTCOMES

In alignment with OEB requirements, the proposed Common and Other OM&A plan supports the achievement of each of the OEB's four RRF outcomes:

- **Customer Focus:** Supports customer priorities relating to reliability, resiliency, technology, and facilities through customer-facing systems, real-time grid operations, outage coordination, planning, engagement and governance.
- **Operational Effectiveness:** Provides the people, tools, systems and governance required for safe and efficient work execution, including continuous real-time operations, IT and OT infrastructure, cybersecurity, investment planning, workforce management, and financial stewardship.
- **Public Policy Responsiveness:** Supports compliance with applicable legislation, licence conditions, market rules, reliability standards, environmental requirements, security obligations, and regulatory filing and reporting requirements.
- **Financial Performance:** Supports manageable and stable rate impacts by pacing and prioritizing expenditures over the forecast period, while continuing to address the highest-priority safety, reliability, compliance, and customer needs. In addition, using centralized shared services, rather than duplicating corporate functions across business segments, avoids unnecessary overhead and enables consistent, scalable support for a materially larger work program.

4.4 ABILITY TO EXECUTE THE PLAN

Hydro One has demonstrated its ability to manage Common and Other OM&A expenditures effectively through the 2023 to 2027 rate period. As discussed in Section 3.0 of this Exhibit, Hydro One prioritized expenditures to support business continuity, maintain compliance, and respond to evolving business and regulatory conditions. This included strengthening its ability to monitor, detect and respond to potential vulnerabilities across its IT and OT environments and maintain the resilience and security of critical systems that support business and grid operations.

Hydro One has the capability, processes and governance to deliver the proposed 2028 to 2032 plan. The 2028 Test Year proposed funding will establish a sustainable operating plan that supports safe, reliable, resilient and secure service for customers.

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CHAPTER 2 APPENDIX 2-N: SHARED SERVICES AND CORPORATE COST ALLOCATION

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COMMON CORPORATE FUNCTIONS AND SERVICES (CCF&S) AND OTHER OM&A

1.0 INTRODUCTION

Hydro One has common corporate functions that provide service on a shared basis to all business units within Hydro One Networks, as well as to affiliates: corporate management, finance, human resources, corporate affairs, general counsel, regulatory affairs, security management, internal audit, and facilities and real estate. Hydro One determined that these functions could be shared effectively by all business units and affiliates, thereby avoiding costly and unnecessary duplication and benefiting customers. These functions are referred to as Common Corporate Functions and Services (CCF&S).

The allocation of CCF&S costs between Hydro One Transmission, Hydro One Distribution, HOSSM, its shareholders and other affiliates is determined by using the common cost allocation methodology described in Exhibit E-04-08. The allocation of these costs between Hydro One Networks and its affiliates is governed by affiliate level service agreements, which are described in Exhibit D-02-03.

This Exhibit describes Hydro One’s CCF&S and Other OM&A costs. Other OM&A costs, discussed in Section 3.0 below, are comprised of credits (offsets to OM&A) associated with capitalized overheads, environmental provision, and indirect depreciation, as well as the non-service cost component of other post-employment benefits (OPEBs) and other costs.

Hydro One continues to benchmark its common corporate costs to assess the efficiency and effectiveness of centralized corporate functions. In 2026, E Source completed a refresh of the common corporate cost benchmarking study using the analytical framework established in the original 2020 assessment and updated cost and operational data. The study found that Hydro One's common corporate costs compare favourably to a peer group of comparable Canadian and U.S. utilities. Overall, four of the nine benchmarked functions were at or near first quartile performance, four were at or near median

performance, and one was near third quartile performance. The E Source benchmarking study is provided as Attachment 1 to this exhibit.

1.1 OVERVIEW OF CCF&S COSTS

Hydro One continues to manage CCF&S costs prudently while making targeted investments to support the growing Transmission and Distribution OM&A envelopes, as outlined in Exhibits E-02-01 and E-03-01, through an increase in workforce requirements, enterprise governance, regulatory obligations, and critical corporate infrastructure. Hydro One continues to pursue efficiencies and disciplined cost management while ensuring these functions are appropriately resourced to support the safe and reliable delivery of transmission and distribution services.

Table 1 below sets out Hydro One's planned expenditures for the 2028 test year, along with the forecast and actual spending level for the bridge and historical years, for each of the CCF&S OM&A categories.

Table 1 - Summary of Total Common Corporate Functions and Services OM&A ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Corporate Management	29.6	36.3	29.6	37.3	36.7	35.7
Finance	25.9	23.3	22.7	23.9	24.5	25.9
Human Resources	33.1	38.7	41.3	53.1	53.5	58.6
Corporate Affairs	20.8	20.7	21.3	27.3	27.4	31.6
General Counsel	11.0	11.6	11.7	18.8	17.0	16.8
Regulatory Affairs	22.8	24.7	30.2	34.5	31.3	35.4
Security Management	8.9	7.9	7.5	9.0	9.2	9.2
Internal Audit	9.3	8.9	7.8	8.5	8.5	9.1
Facilities and Real Estate	69.0	70.9	65.1	64.3	64.7	80.9
Total	**230.3**	**242.9**	**237.1**	**276.6**	**272.8**	**303.2**
Allocated to Transmission	**99.9**	**102.1**	**104.5**	**115.8**	**113.3**	**139.0**
Allocated to Distribution	**97.1**	**102.0**	**96.8**	**113.7**	**113.0**	**115.5**
Allocated to HOSSM	**0.6**	**0.4**	**0.6**	**0.7**	**0.7**	**0.9**
Allocated to Other[1]	**32.8**	**38.4**	**35.2**	**46.4**	**45.8**	**47.8**

The 2028 test year expenditure for CCF&S OM&A is $303.2M, a $72.9M increase over 2023 actuals, and a $51.3M increase above average annual expenditures during the 2023-2027 period.

From 2023 to 2027, total CCF&S costs increased by approximately $42.5M, reflecting an annual growth rate of approximately 4.3%. Over this period, Hydro One managed material cost pressures, including inflationary increases, growing workforce requirements, and an expanding regulatory environment, through deliberate trade-offs, reprioritization of activities, and productivity improvements that supported the management of cumulative OM&A expenditures over the five-year rate period. However, operating within these constraints has required the deferral or limitation of investments in key corporate

[1] As discussed in Exhibit E-04-08, Section 3.0, the amounts allocated to “Other” in Table 1 above reflect costs allocated to Hydro One Network’s affiliates

capabilities, including technology enablement, planning and analytical capacity, compliance support, and workforce development. As business requirements have continued to evolve, incremental investments in Common and Other OM&A functions are now required beginning in 2028 to sustain effective corporate services, meet increasing regulatory and operational requirements, and support the organization's growing needs.

In the upcoming 2028–2032 period, Hydro One is scaling its Transmission and Distribution capital and OM&A plans to meet growing and changing customer and system investment needs as outlined in the System Plans, Section 2.0 and 3.0. CCF&S expenditures must also increase to support the effective planning, execution and oversight of these expanded work programs, and maintain compliance with Hydro One's legal and regulatory obligations. Incremental CCF&S costs are required to ensure Hydro One has the people, tools, systems, governance and processes needed to manage higher work volumes, address incremental work requirements, and deliver improved reliability and service outcomes for customers.

The 2028 test year Expenditure is $30.4M over the 2027 bridge year forecast. The largest drivers of the increase in CCF&S OM&A spend are additional targeted investments to support evolving business, operational, and regulatory requirements. The following are the main contributing factors:

- Higher Facilities and Real Estate costs due to lease renewals and fixed operating costs for new facilities;
- Higher Human Resources costs owing to investments to support Hydro One's People Strategy, workforce requirements, and enterprise transformation initiatives;
- Higher Regulatory Affairs costs driven by increased regulatory activities and obligations associated with supporting Hydro One's business and rate application requirements; and
- Higher Corporate Affairs costs related to investments in stakeholder, customer, and external engagement activities.

As outlined in Table 1 above, $139.0M or 46% of CCF&S expenditures are allocated to Transmission and $115.5M or 38% are allocated to Distribution. Transmission and Distribution funding is discussed in Sections 1.2 and 1.3, respectively. As discussed in Exhibit E-04-08, Section 3.0, the amounts allocated to "Other" in Table 1 above reflect costs allocated to Hydro One Network's affiliates. Costs allocated to other Hydro One businesses increase from $32.8M in 2023 to $45.8M in the 2027 bridge year and $47.8M in the 2028 test year, reflecting the continued allocation of corporate support costs to non-regulated businesses and reducing the amount recovered from transmission and distribution customers.

1.2 ALLOCATION TO TRANSMISSION

The allocation of program level costs to Transmission is shown in Table 2.

Table 2 - CCF&S Costs Allocated to Transmission ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Corporate Management	3.4	4.2	5.9	3.9	3.8	3.9
Finance	9.6	8.8	9.1	8.5	8.6	10.8
Human Resources	16.3	18.8	20.5	23.4	23.4	34.2
Corporate Affairs	8.6	8.1	7.4	9.7	9.6	12.6
General Counsel	5.4	5.8	5.9	10.1	9.6	6.3
Regulatory Affairs	11.4	12.4	15.1	17.8	15.8	22.5
Security Management	4.3	3.8	3.6	4.8	4.8	5.0
Internal Audit	4.5	3.9	3.4	3.4	3.4	3.9
Facilities and Real Estate	36.4	36.3	33.5	34.3	34.3	39.6
Total CCF&S Costs Allocated to Transmission	**99.9**	**102.1**	**104.5**	**115.8**	**113.3**	**139.0**

The 2028 test year expenditure for CCF&S allocated to Transmission is $139.0M, a $39.1M increase over 2023 actuals, and a $31.9M increase above average annual expenditures during the 2023-2027 period. These increases are driven by the same factors impacting the overall amounts in Table 1: specifically, between 2023 and 2028, Human Resources and Regulatory Affairs grew by 110% and 97%, respectively, acting as

the primary drivers of the 39% growth in CCF&S costs allocated to Transmission over the same period.

1.3 ALLOCATION TO DISTRIBUTION

The allocation of program level costs to Distribution is shown in Table 3.

Table 3 - CCF&S Costs Allocated to Distribution ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Corporate Management	3.4	4.5	4.3	6.2	6.3	6.2
Finance	11.0	10.3	9.9	11.1	11.5	12.1
Human Resources	16.1	18.6	18.8	24.6	25.1	18.6
Corporate Affairs	9.9	10.7	8.2	12.0	12.1	14.2
General Counsel	4.4	4.1	3.3	6.6	5.4	5.7
Regulatory Affairs	10.6	11.4	13.6	15.3	14.1	10.0
Security Management	4.5	4.0	3.6	4.1	4.2	3.9
Internal Audit	4.7	4.3	3.5	4.3	4.3	4.0
Facilities and Real Estate	32.5	34.2	31.5	29.6	30.0	40.8
Total CCF&S Costs Allocated to Distribution	**97.1**	**102.0**	**96.8**	**113.7**	**113.0**	**115.5**

The 2028 test year expenditure for CCF&S allocated to Distribution is $115.5M, an $18.4M increase over 2023 actuals, and an $11.0M increase above average annual expenditures during the 2023-2027 period. These increases are driven by the same factors impacting the overall amounts in Table 1: specifically between 2023 and 2028, Facilities and Real Estate and Corporate Affairs grew by 26% and 43%, respectively, acting as the primary drivers of the 19% growth in CCF&S costs allocated to Distribution over the same period.

2.0 CCF&S PROGRAM DESCRIPTIONS AND EXPENDITURES

2.1 CORPORATE MANAGEMENT

Corporate Management represents those functions responsible for providing overall strategic direction to Hydro One. Corporate Management costs relate to the Board of Directors, the Chief Executive Officer (CEO) Office, the Treasurer, the Chief Financial Officer (CFO) Office, the Ombudsman Office, the General Counsel, and the Corporate Secretary as advisors to the Board of Directors and corporate officers on overall strategic matters. Table 4 presents the details of Hydro One's total Corporate Management costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 4 - Summary of Allocated Corporate Management Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
CFO Office	2.1	3.0	2.1	1.9	2.1	2.4
Board	4.4	4.8	4.9	5.3	5.3	5.3
Corporate Development	2.2	2.7	7.1	9.5	9.0	8.2
VP General Counsel, Chief Ethics Officer and Corp. Secretary	2.2	2.7	2.7	1.8	1.8	1.9
Strategy & Innovation	4.8	5.6	3.8	7.1	6.9	6.9
Treasurer's Office	0.0	0.0	0.0	0.0	0.0	0.0
Chair	0.2	0.2	0.4	0.0	0.0	0.0
President/CEO Office	4.2	6.2	4.7	5.5	5.3	5.4
Ombudsman Office	1.1	1.2	1.3	1.7	1.7	1.5
Investor Relations	2.0	2.1	0.8	2.3	2.3	2.4
Corporate Common LTD	4.4	5.4	1.6	2.1	2.2	1.7
Pension	2.2	2.5	0.2	0.1	0.1	0.1
Total Corporate Management Costs	**29.6**	**36.3**	**29.6**	**37.3**	**36.7**	**35.7**
Allocated to Transmission	3.4	4.2	5.9	3.9	3.8	3.9
Allocated to Distribution	3.4	4.5	4.3	6.2	6.3	6.2
Allocated to HOSSM	0.0	0.0	0.0	0.0	0.0	0.1
Other	22.8	27.6	19.4	27.3	26.6	25.5

The E Source benchmarking study provided as Attachment 1 to this Exhibit found that Hydro One's Corporate Management costs are slightly below the median level relative to the comparator group on a normalized basis. The study also notes that the benchmarked costs are evaluated on a pre-allocation basis and include costs that are ultimately borne by entities other than Hydro One Transmission and Distribution, as well as certain shareholder-borne costs.

The 2028 test year expenditure for Corporate Management is $35.7M, a $6.1M increase over 2023 actuals and a $1.8M increase above average annual expenditures during the 2023-2027 period. As demonstrated in Table 4 above, the majority of Corporate Management costs are not recoverable from Transmission or Distribution customers. In the 2028 test year, of the total Corporate Management costs of $35.7M, only $3.9M and $6.2M are allocated to Transmission and Distribution, respectively, while $25.5M is allocated to Other.

The costs allocated to Other include activities such as Strategy & Innovation, Corporate Donations, Investor Relations, and certain Corporate Management costs that are borne by Hydro One's shareholders rather than customers. Although the Hydro One Accountability Act, 2018 (Bill 2), which established this treatment for certain costs, was repealed in 2023, Hydro One has continued to exclude these costs from rate recovery. This treatment is consistent with the E Source study's observation that not all benchmarked corporate management costs are ultimately recovered through Transmission and Distribution rates.

2.2 FINANCE

Hydro One's Finance division provides strategic advice and services related to the planning, processing, recording, reporting, and monitoring of financial transactions across the Hydro One group of companies. The Finance division performs the following functions: corporate controller services, corporate tax services and treasury services. Table 5 presents the details of Hydro One's total Finance costs and their allocation to Hydro One

Transmission, Hydro One Distribution, HOSSM, and other business segments and affiliates.

Table 5 - Summary of Allocated Finance Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Finance Costs	**25.9**	**23.3**	**22.7**	**23.9**	**24.5**	**25.9**
Allocated to Transmission	9.6	8.8	9.1	8.5	8.6	10.8
Allocated to Distribution	11.0	10.3	9.9	11.1	11.5	12.1
Allocated to HOSSM	0.4	0.2	0.1	0.2	0.2	0.1
Other	4.9	4.1	3.6	4.1	4.2	2.9

The E Source benchmarking study provided as Attachment 1 to this Exhibit benchmarked Hydro One's Finance costs at slightly below first quartile levels relative to its peer group, indicating that Hydro One's Finance function compares favourably with similar utilities. The study found that Hydro One's Finance costs per million dollars of revenue were below first quartile benchmark levels when compared to the comparator group.

The 2028 test year expenditure for Finance is $25.9M, no material increase over 2023 actuals, and a $1.8M increase above average annual expenditures during the 2023-2027 period. Total Finance costs declined from $25.9M in 2023 to $22.7M in 2025, reflecting organizational efficiencies and cost optimization initiatives implemented across the Finance function, and remained relatively stable through the 2027 Bridge year. Finance costs increase to $25.9M in the 2028 test year to support Hydro One's expanding work program and the increasing scale and complexity of the regulated business, including rate application activities, regulatory reporting, regulatory account management, business planning, compliance requirements, and insurance and risk management activities.

The Finance division performs multiple functions, each of which is described in the subsections below.

2.2.1 CORPORATE CONTROLLER

The Corporate Controller function provides leadership and direction with respect to financial reporting, corporate and regulatory accounting, business planning, budgeting, forecasting, accounting and internal control policies, and procedures to ensure statutory and regulatory compliance and consistency with U.S. GAAP. The group is also accountable for expense management functions, ensuring the automated expense reporting tool operates as designed.

This group oversees the development of actual and forecast financial information and manages reporting processes for appropriate audiences and stakeholders. It leads Hydro One's annual business planning, budgeting, forecasting, and financial analysis processes, and supports strategic decision-making through business case reviews, business valuations, transaction support, and financial modelling. The group is also responsible for managing and providing direction to the Company on internal financial control matters, employing measures such as organization authority registers and financial policies and procedures. In addition, it ensures the Company's compliance obligations pursuant to Ontario securities laws, including the Multi-Jurisdictional Disclosure System rules for a foreign issuer registered with the U.S. Securities and Exchange Commission are met.

The Corporate Controller group manages increasingly complex statutory, regulatory, and external reporting requirements, including financial reporting, regulatory reporting, debt and equity financing activities, and financial planning and performance reporting. These requirements continue to evolve and require timely and accurate execution. Timely compliance helps maintain the Company's positive standing within the capital markets, which supports access to cost-effective financing. The group is also responsible for ensuring adherence to regulatory and accounting principles and maintaining the integrity, accuracy, and reliability of Hydro One's financial reporting and forecasting processes.

2.2.2 CORPORATE TAX

Corporate Tax group manages the tax affairs (i.e., compliance, audits, and planning) for each corporate entity, partnership and trust within the Hydro One group of companies. This includes matters related to corporate income taxes, excise tax, land transfer tax, and non-resident withholding tax. Corporate Tax services ensure that internal and external tax compliance requirements are met. Moreover, tax consulting services are provided to other departments with respect to payroll tax, taxable benefits, agreements, financing, and all transactions and information related to tax costs for regulatory purposes.

2.2.3 TREASURY

Treasury costs are associated with the following activities:

- Executing on borrowing plans and issuing commercial paper and long-term debt;
- Ensuring compliance with securities regulations, banks and debt covenants;
- Managing the Company's daily liquidity position, controlling cash and managing the Company's bank accounts;
- Settling all transactions and managing relationships with creditors; and
- Communicating with debt investors, banks and credit rating agencies.

A portion of the Treasury budget is recovered through the cost of long-term debt, as described in Exhibit F-01-02 and outlined in Exhibit F-01-04.

Included in Treasury costs are expenses for the negotiations and purchases of insurance policies, and claims management and settlement. These expenses cover premiums paid for Corporate Functions and Services insurance coverage and the cost to self-insure against liability exposures that are either not covered by insurance policies or fall below the specified deductibles.

Table 6 below shows the premiums for all of Hydro One Inc.'s Corporate Functions and Services insurance policies and the cost of self-insurance for the 2023-2028 period. Corporate Functions and Services Insurance Policies are liability policies that cannot be readily assigned to a specific line of business. Self-insurance costs for the 2027 and 2028

period reflect the Company's risk exposures, its long-term history of claims, the deductible on the liability policies, and liability payments to third parties. The main contributors to self-insurance costs are third-party claims, which can fluctuate from year to year.

Table 6 - Summary of Allocated Insurance Costs ($M)[2]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Premiums paid for Corporate Functions and Services Insurance Policies	3.0	2.9	2.9	2.9	3.1	3.3
Self-Insurance Cost	3.2	0.7	0.6	1.1	1.0	1.2
Total Insurance Costs	**6.2**	**3.6**	**3.5**	**4.0**	**4.1**	**4.5**
Allocated to Transmission	2.8	1.6	1.6	1.8	1.9	1.9
Allocated to Distribution	3.4	2.0	1.9	2.2	2.2	2.6

2.3 HUMAN RESOURCES

The Human Resources ("HR") function is responsible for the development, delivery, and administration of Hydro One's people strategies, programs, and services. Through Hydro One's People Strategy, HR supports the attraction, development, engagement, compensation, health and well-being, and retention of employees, while ensuring compliance with legislative requirements, collective agreements, corporate policies, and governance requirements.

HR works in partnership with business leaders across the organization to align workforce strategies with Hydro One's operational and strategic objectives. The function plays a critical role in ensuring Hydro One has the workforce, leadership capability, organizational structure, and employee programs necessary to safely and effectively deliver its operating and capital programs.

[2] The cost of other insurance coverage that applies to only certain lines of business is captured and reported by the lines of business where coverage is applicable

The HR function provides centralized expertise and services in workforce planning and analytics, talent acquisition, talent management, compensation, employee engagement, pension, benefits and wellness, disability management, employee and labour relations, and HR technology and operations. HR is also responsible for supporting organizational design, succession planning, collective bargaining, employee wellness programs, regulatory compliance, and the administration of employee programs throughout the employee lifecycle.

As Hydro One continues to execute a significant capital investment program and manage an increasingly complex operating environment, HR supports the recruitment and development of skilled employees across both represented and non-represented employee groups. The function also supports workforce renewal initiatives, leadership development, succession management, employee retention, labour relations, and organizational effectiveness programs that enable the Company to maintain a skilled, safe, and productive workforce.

Table 7 presents the details of Hydro One's total HR costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 7 - Summary of Allocated Human Resources Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Human Resources Costs	**33.1**	**38.7**	**41.3**	**53.1**	**53.5**	**58.6**
Allocated to Transmission	16.3	18.8	20.5	23.4	23.4	34.2
Allocated to Distribution	16.1	18.6	18.8	24.6	25.1	18.6
Allocated to HOSSM	0.0	0.0	0.0	0.1	0.1	0.0
Other	0.7	1.3	2.0	5.0	5.0	5.8

The E Source benchmarking study provided as Attachment 1 to this Exhibit benchmarked Hydro One's HR costs slightly above the median relative to its peer group. The study noted that HR costs include the policies, systems, and programs required to attract, manage,

engage, and retain a workforce, including recruiting and development, HR services, health and wellness, diversity initiatives, and employee and labour relations activities.

The 2028 test year expenditure for HR is $58.6M, a $25.5M increase over 2023 actuals, and a $14.7M increase above average annual expenditures during the 2023-2027 period. These increases over the current rate period that continue into the 2028 test year reflect investments required to support Hydro One's growing workforce, evolving business needs, and long-term talent strategy as outlined in Exhibit E-06-02. These investments strengthen workforce planning, recruitment, employee development, leadership capability, labour relations, employee wellness, HR technology, and other people-related services and capabilities required to support Hydro One's operations and capital investment plans.

The Human Resources department performs multiple functions, which are described in the subsections below.

2.3.1 BUSINESS HR

Business HR serves as the primary interface between the business and the Human Resources function, translating business priorities into workforce strategies and facilitating access to specialized HR expertise. The team plays a key role in supporting organizational effectiveness, workforce readiness, leadership capability, and the successful implementation of enterprise initiatives that affect Hydro One's workforce. This function is delivered through Human Resource Business Partners who work closely with business leaders to align workforce strategies with operational and corporate objectives. HR Business Partners support workforce planning, succession planning, organizational design, talent management, leadership effectiveness, advice on employee and labour relations matters, and the execution of enterprise-wide people initiatives. The team acts as a conduit between the business and specialized HR centers of expertise, helping leaders address workforce challenges, manage organizational change, and build the capabilities required to support Hydro One’s long-term business objectives.

2.3.1.1 HR SHARED SERVICES

The HR Shared Services team is a centralized hub for HR administrative activities and services related to employee life-cycle events, such as hiring, leave of absence, promotion, and retirement, focused on streamlined processes and consistent service delivery for employees, managers, and pensioners. This team encompasses the HR Service Centre (HRSC), Workforce Acquisition (WFA), HR Technology and Effectiveness groups.

The HRSC is typically the first point of contact for all regular status employees and pensioners on HR issues, and performs nearly all administrative activities related to employee life-cycle events, such as hiring, leaves of absence and promotion.

The WFA team works in coordination with the Lines of Business to manage the casual trades staff across Hydro One. This team performs tasks related to the life cycle of the casual workforce. Casual trades employees represent nearly a third of Hydro One's workforce (CUSW, EPSCA groups, PWU HH) and are retained and deployed with minimal lead time to support time-sensitive and project-based work programs.

The HR Effectiveness and Technology teams manage HR processes, policies, and systems with the objective of supporting and enhancing HR capabilities while ensuring corporate and legislative compliance. This team manages and maintains the existing HR technology systems and leading implementation of new technologies.

2.3.2 TALENT ACQUISITION

The Talent Acquisition team is responsible for attracting and recruiting qualified candidates to meet Hydro One's workforce requirements. The team supports hiring across represented and non-represented employee groups, including regular, temporary, student, and executive or specialized positions, and works closely with business leaders to address current and future workforce needs.

In addition to recruitment delivery, the team leads workforce attraction initiatives, including campus recruitment programs, Indigenous talent attraction strategies, apprenticeship

recruitment, and diversity, equity and inclusion-focused hiring initiatives. The team also supports employment branding, workforce sourcing strategies, and labour market intelligence to help Hydro One attract and secure qualified talent in a competitive labour market.

The Talent Acquisition team plays a critical role in supporting the delivery of Hydro One's investment plans by ensuring the timely recruitment of qualified employees to fill new positions, backfill attrition, and address emerging workforce requirements. Effective recruitment is particularly important in specialized labour markets where qualified candidates are limited and competition for talent is significant.

2.3.3 TALENT MANAGEMENT

The Talent Management team delivers core programs relating to performance management, succession planning, and organizational learning and development. Given Hydro One’s performance-based pay structure for management employees, this team is focused on ensuring the standards for performance are aligned with market and Hydro One’s strategic objectives, as well as providing the skills and tools required to set goals and track performance. Performance-based compensation requires enhanced rigour and tracking, accountability, and mature judgement and leadership. Although performance-based compensation results in a best-in-class utility, it creates additional responsibilities and accountabilities for managers, directors, and VPs in order to maintain this program’s effectiveness and integrity, hence the active role the Talent Management team (and Compensation team) plays in its oversight and delivery.

The Talent Management team is also focused on addressing retention and leadership succession within the non-unionized workforce. As this segment of the workforce is not eligible for compensation programs that are correlated with retention (such as the Defined Benefit pension plan), this group is at even greater risk of turnover.

Talent Management programs enable Hydro One to: maintain a performance and safety oriented culture, minimize disruption due to turnover within the management segment,

empower leaders to drive productivity and efficiency, and diversify its talent pool to create a representative and inclusive workforce.

2.3.4 EMPLOYEE ENGAGEMENT

The Employee Engagement team is responsible for Hydro One's employee listening strategy, including the design, administration, and analysis of employee surveys and feedback mechanisms. The team oversees the annual employee engagement survey, pulse surveys, and other employee feedback channels to measure workforce sentiment, identify emerging trends, and assess the effectiveness of organizational initiatives.

Employee Engagement analyzes and interprets employee feedback and engagement data and works in collaboration with Business HR to provide insights to leaders, support evidence-based decision-making, and inform action planning across the organization. The team works with business leaders and Human Resource Business Partners to translate survey results into targeted actions aimed at strengthening employee engagement, improving the employee experience, and supporting organizational effectiveness.

2.3.5 COMPENSATION

The Compensation team is responsible for the administration of the broad-based and executive compensation programs for management and represented employees including job evaluation, salary administration, the annual compensation cycle and supporting the collective bargaining process. This team is also responsible for the management and administration of all equity programs at Hydro One for both management and represented employees in addition to managing the administration of the long-term incentive plan. The team also supports the annual disclosure components detailed above, and conducts ongoing review of compensation programs and practices more broadly to ensure Hydro One is aligned with market best practices and emerging trends.

2.3.6 EMPLOYEE RECOGNITION

The Recognition Manager develops and administers employee recognition programs that support employee engagement and reinforce organizational values and behaviours. The

team provides recognition tools and resources to leaders, manages service and achievement award programs, and oversees initiatives designed to acknowledge employee contributions across the organization.

2.3.7 REPORTING AND ANALYTICS

The Reporting and Analytics team is accountable for HR metrics reporting, headcount and resource planning, predictive analytics, and workforce optimization. This group is focused on evolving the existing operational activities into a more strategic/proactive program which supports the business. To drive this effort, current HR processes and technology must be enhanced through investment in replacing legacy systems, and establishing analytics-focused decision-making reflexes.

2.3.8 PENSION, BENEFITS & WELLNESS

The Pension, Benefits & Wellness team is responsible for the design, administration, and governance of Hydro One’s pension, benefits, and wellness programs. The team administers the Company's defined benefit and defined contribution pension plans and oversees employee and retiree benefits programs, including health, dental, life insurance, and post-retirement benefits. In addition, the team manages employee and family assistance programs, relocation support, and enterprise wellness programs that promote the physical, mental, and financial well-being of employees.

The team also provides strategic oversight of benefit plan design, vendor management, regulatory compliance, and program effectiveness to ensure programs remain competitive, sustainable, and aligned with employee and business needs.

2.3.9 DISABILITY MANAGEMENT

The Disability Management team is responsible for the administration and oversight of occupational and non-occupational disability programs, including sick leave, long-term disability, workplace accommodation, return-to-work planning, and Workplace Safety and Insurance Board ("WSIB") claims management. The team works collaboratively with Business HR, employees, leaders, healthcare providers, and external administrators to

support employee recovery and safe, timely returns to productive work while ensuring compliance with applicable legislation, collective agreements, and corporate policies.

2.3.10 EMPLOYEE & LABOUR RELATIONS

The Employee and Labour Relations team provides specialized expertise and support to leaders across Hydro One on a broad range of workplace matters involving both represented and non-represented employees. The team is responsible for promoting the fair, consistent, and compliant application of employment policies, collective agreements, and applicable legislation, while supporting Hydro One's operational and strategic objectives.

The Employee Relations component of the team provides advice and support to managers on complex employee matters. This includes the administration and investigation of alleged violations of Hydro One's Code of Business Conduct, workplace harassment and discrimination complaints, and other sensitive employee relations issues. The team also administers Hydro One's Fit for Duty Program, providing guidance to leaders on fitness for work matters and supporting the Company's obligations related to employee health, safety, and accommodation. Through these activities, the Employee Relations team helps maintain a respectful, safe, and productive workplace while managing organizational risk.

The Labour Relations component of this team provides strategic advice, and training to managers regarding complex collective agreements and related provincial legislation. Given the highly-unionized nature of Hydro One, as well as the complexity and comprehensiveness of its collective agreements, this group provides essential advice relating to staffing competitions & selections, accommodation, external contracting, discipline, performance, leave entitlements, as well as operational matters such as work schedules, location of work, and assignment of duties. This group also oversees the grievance and arbitration process, providing essential advice for the resolution of disputes and advancing Hydro One’s strategic objectives.

Hydro One is a party to multiple collective agreements and a number of mid-term agreements and letters of understanding. The Labour Relations group is responsible for the re-negotiation of the Power Workers Union (PWU), Society of United Professionals (SUP), Canadian Union of Skilled Workers (CUSW) collective agreements and administers all related mid-term agreements and letters of understanding. In light of the relatively short duration of renewal agreements with its core units, the SUP and PWU, the frequency of bargaining cycles has increased, putting greater pressure on the resources of this group. Additionally, as a member of EPSCA, Hydro One is a participant in negotiations with the 17 casual trades bargaining units affiliated with this organization.

2.3.11 ENTERPRISE TRANSFORMATION OFFICE (ETO)

The Enterprise Transformation Office (ETO) was established to enable coordinated, enterprise-wide execution of Hydro One's priorities, in response to increasing scale, complexity, and interdependencies across transformation efforts. The ETO provides an integrated, enterprise portfolio view of transformation initiatives, including scope, timing, interdependencies, costs, benefits, and resource requirements, to support prioritization, sequencing, and executive decision-making.

The ETO leads enterprise change management by aligning and sequencing initiatives, assessing cumulative impacts on the organization, and reducing change fatigue across the workforce. The ETO supports leadership capability development by equipping leaders with standardized tools, governance, and coaching to effectively sponsor, lead, and sustain change.

The ETO embeds cost, productivity, and value discipline into transformation delivery by establishing consistent tracking of benefits realization and performance at both the initiative and portfolio levels. The ETO operates as an enablement function that partners with business units, initiative owners, and corporate functions to accelerate execution, ensure alignment with corporate strategy, and make transformation progress visible and measurable.

2.4 CORPORATE AFFAIRS

Corporate Affairs consists of two primary functions: (i) Indigenous Partnerships and Business Development (IPBD), which advances Hydro One's relationships with Indigenous communities and supports Indigenous engagement, participation, and economic development opportunities; and (ii) Communications and Stakeholder Relations, which manages customer communications, marketing, stakeholder and government relations, public policy support, and community engagement activities.

Table 8 presents the details of Hydro One's total Corporate Affairs costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 8 - Summary of Corporate Affairs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Corporate Affairs Costs	**20.8**	**20.7**	**21.3**	**27.3**	**27.4**	**31.6**
Allocated to Transmission	8.6	8.1	7.4	9.7	9.6	12.6
Allocated to Distribution	9.9	10.7	8.2	12.0	12.1	14.2
Allocated to HOSSM	0.0	0.0	0.1	0.1	0.1	0.2
Other	2.3	1.8	5.6	5.5	5.6	4.6

The E Source benchmarking study provided as Attachment 1 to this Exhibit benchmarked Hydro One's Corporate Affairs costs slightly above the third quartile relative to its peer group. The study noted that Corporate Affairs costs include Indigenous Partnerships and Business Development activities, an area in which Hydro One maintains a robust function compared to many peer utilities. The study further found that excluding these costs would reduce Hydro One's normalized Corporate Affairs costs to a level closer to the peer group median. However, Hydro One has identified Indigenous Partnerships as a strategic priority to support meaningful and long-term relationships with Indigenous partners. The IPBD and Communications and Stakeholder Relations departments are further described below.

The 2028 test year expenditure for Corporate Affairs is $31.6M, a $10.8M increase over 2023 actuals, and an $8.1M increase above average annual expenditures during the 2023-2027 period. Expenditures increased at an average annual rate of approximately 7.1% between 2023 and the 2027 bridge year. A significant portion of this growth occurred between 2025 and 2026, when expenditures increased from $21.3M to $27.3M. This increase primarily reflects organizational realignment, including the consolidation of certain regulatory and stakeholder engagement responsibilities, as well as expanded Indigenous engagement, stakeholder consultation, advocacy, sustainability, and communications activities. The further increase in the 2028 test year reflects additional requirements associated with evolving business priorities and project commitments.

2.4.1 INDIGENOUS PARTNERSHIPS AND BUSINESS DEVELOPMENT

The IPBD team helps Hydro One develop and maintain mutually beneficial long-term relationships with Indigenous communities who may be impacted by Hydro One's projects and operations. The team's mandate is to advance community-led engagement and includes: (i) undertaking procedural aspects of consultation, guided by law, best practices, and the priorities of Indigenous communities, as early as possible during projects and throughout development; (ii) engaging with Indigenous communities during operations and maintenance activities to provide information and opportunities for input on work which may impact the Indigenous community; (iii) ensuring Hydro One's employees have the skills, training and resources necessary to perform their duties while advancing relationships with Indigenous communities based on mutual respect and understanding of the unique rights of Indigenous people; (iv) advocating for and supporting efforts to increase procurement opportunities for Indigenous businesses; (v) supporting efforts to increase Indigenous employee representation at all levels in Hydro One's workforce; (vi) supporting efforts to increase Indigenous community investment, sponsorships, and grant programs for positive and lasting socio-economic outcomes; (vii) seeking good faith resolution of transmission and distribution line issues on First Nation reserve lands in a fair manner; and (viii) supporting Indigenous education and training opportunities.

Indigenous Partnerships expenditures reflect Hydro One's commitment to meeting its delegated legal Duty to Consult obligations and strengthening partnerships with Indigenous communities. Increasing expectations from Indigenous communities, together with Crown requirements related to Hydro One's delegated Duty to Consult responsibilities associated with section 35 Aboriginal and Treaty Rights, have increased the volume and complexity of engagement required to support projects and ongoing operations. As communities advance evolving energy, infrastructure, reliability, and economic development priorities, Hydro One also must maintain sufficient capacity, a strong local presence, and timely, meaningful engagement to ensure their energy needs are met. These investments will support enhanced field presence, consultation, community partnership, and system operations and development activities that enable Hydro One to build and sustain long-term relationships, support Indigenous participation in the energy sector, and respond to evolving community priorities. They also help ensure that consultation obligations are fulfilled effectively, enabling the critical work required to maintain and grow Ontario's electricity system to proceed.

Hydro One's Indigenous Relations Engagement Strategy is further described in SPF Exhibit B-01-01 Section 1.6.4.5

2.4.2 COMMUNICATIONS AND STAKEHOLDER RELATIONS

Communications develops customer communication material to ensure customers are aware of the Company’s programs, upgrades, planned and unplanned power outages. The team is also accountable for customer education, media relations, and web communications for Hydro One’s corporate website.

Stakeholder Relations manages the Company’s relationship with external stakeholders, the government, energy agencies, municipal associations, industry associations, and energy sector stakeholders. The team is also responsible for providing the Company with strategic advice and support on public policy, projects, customer programs, and other initiatives. The team also leads public consultation, and community engagement in support of new development projects, maintenance work, and forestry programs.

2.5 GENERAL COUNSEL

The Law Department, Ethics Office and Corporate Secretariat group comprise the General Counsel function at Hydro One.

The Law Department performs the following primary function:

- Provides legal services relating to all of Hydro One's activities, including financing and capital markets transactions, regulatory matters, mergers and acquisitions, litigation, transmission and distribution operations, employment and labour matters, and health, safety, and environmental matters.

The Corporate Secretariat group performs the following primary functions:

- Provides corporate secretariat services to the Chair of the Board, the Board of Directors, and its committees, including advice regarding governance practices, regulatory requirements, and emerging governance trends; and

The Ethics Office performs the following primary functions:

- Provides advice and oversight with respect to Hydro One's Code of Business Conduct, including administration of Code-related inquiries, investigations, compliance activities, and periodic updates to the Code.

Table 9 presents the details of Hydro One's total General Counsel costs and their allocation to Hydro One Transmission, Hydro One Distribution, HOSSM, and other business segments and affiliates.

Table 9 - Summary of Allocated General Counsel Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total General Counsel Costs	**11.0**	**11.6**	**11.7**	**18.8**	**17.0**	**16.8**
Allocated to Transmission	5.4	5.8	5.9	10.1	9.6	6.3
Allocated to Distribution	4.4	4.1	3.3	6.6	5.4	5.7
Allocated to HOSSM	0.1	0.1	0.3	0.3	0.2	0.1
Other	1.0	1.7	2.1	1.8	1.8	4.7

The E Source benchmarking study, provided as Attachment 1 to this Exhibit, benchmarked Hydro One's legal costs slightly below first quartile levels relative to its peer group, indicating that Hydro One's legal function compares favourably with comparable utilities. The study noted that legal costs include services required to ensure compliance with applicable laws, provide legal advice and representation, and deliver corporate secretariat functions.

The demand for legal and corporate secretariat services is driven by Hydro One's capital and OM&A programs, regulatory proceedings, financing activities, governance obligations, and evolving legislative and regulatory compliance requirements. Hydro One continues to perform most legal work internally, leveraging external counsel where specialized expertise is required or where workload levels exceed internal capacity.

The 2028 test year expenditure for General Counsel is $16.8M, a $5.8M increase over 2023 actuals, and a $2.8M increase above average annual expenditures during the 2023-2027 period. A significant portion of this growth occurred between 2025 and 2026, when expenditures increased from $11.7M to $18.8M. This increase is primarily attributable to planned legal fees as part of legal support requirements associated with Hydro One's growing capital program, business growth, Indigenous partnerships, regulatory matters, securities filings, and increased litigation activity, resulting in higher utilization of external legal counsel and specialized legal services. The 2028 expenditures reflect the continued need for external legal counsel and specialized legal support across capital, regulatory, and growth-related activities.

2.6 REGULATORY AFFAIRS

The Regulatory Affairs Department is charged with developing effective regulatory filings (rates; mergers, acquisitions and divestitures; leaves-to-construct; service area amendments; load transfers, etc.), and any motions to review or appeals on decisions, as well as preparing load forecasts in support of investments and rate applications. The Regulatory Affairs staff prepare witnesses across the Company for rate adjudications and build and maintain relationships with senior members at the regulators and similar bodies

including the Ontario Energy Board (the OEB), Canada Energy Regulator (CER), and Independent Electricity System Operator (IESO) and other stakeholders.

The Regulatory Affairs Department also manages the Company's compliance with reliability standards set by bodies such as the Independent Electricity System Operator (IESO) and the North American Electric Reliability Corporation (NERC). This Department's mandate also includes developing effective processes and proactively monitoring and reporting regulatory compliance in Ontario, and national and internal regulatory requirements related to reliability standards and critical infrastructure protection.

Table 10 presents the details of Hydro One's total Regulatory Affairs costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 10 - Summary of Allocated Regulatory Affairs Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Regulatory Affairs	10.8	11.6	15.5	17.9	14.3	16.1
OEB/Other Costs	12.0	13.1	14.7	16.6	17.0	19.3
Total Regulatory Affairs Costs	**22.8**	**24.7**	**30.2**	**34.5**	**31.3**	**35.4**
Allocated to Transmission	11.4	12.4	15.1	17.8	15.8	22.5
Allocated to Distribution	10.6	11.4	13.6	15.3	14.1	10.0
Allocated to HOSSM	0.0	0.0	0.0	0.0	0.0	0.2
Other	0.8	0.9	1.5	1.5	1.3	2.7

The E Source benchmarking study provided as Attachment 1 to this Exhibit benchmarked Hydro One's Regulatory Affairs costs at approximately median levels relative to its peer group. The study found that Hydro One's Regulatory Affairs costs per million dollars of revenue were effectively at the median of comparator utilities. E Source noted that Regulatory Affairs costs are associated with regulatory strategy, regulatory filings and proceedings, coordination of regulatory submissions, and interactions with regulatory agencies, excluding regulator assessments and user fees. The study concluded that

Hydro One's Regulatory Affairs function remained competitive relative to comparable North American utilities.

The 2028 test year expenditure for Regulatory Affairs is $35.4M, a $12.6M increase over 2023 actuals, and a $6.7M increase above average annual expenditures during the 2023-2027 period. The increase over the 2023-27 period and into the 2028 test year reflects the resources required to support Hydro One's regulatory obligations and business activities, including major rate applications, leave-to-construct proceedings, regulatory compliance requirements, reliability standards compliance, and growing stakeholder and regulatory engagement activities. The increase also reflects forecast OEB and other regulatory costs associated with planned regulatory proceedings over the forecast period.

The Regulatory Affairs division performs a number of distinct functions, which are described in this section.

2.6.1 COMPLIANCE

The Compliance function manages Hydro One’s compliance with the regulations and policies of the OEB, the IESO, and the CER as they apply to Hydro One’s distribution and transmission businesses and its subsidiaries.

The Reliability Standards and Compliance Assurance group reports on the implementation and demonstration to the IESO of compliance with primarily NERC-based reliability standards and Critical infrastructure Protection. The Regulatory Compliance group monitors and advises on implementation of initiatives relating primarily to OEB Codes. The Regulatory Research and Administration group also manages the filing of applications and information with Regulatory bodies, such as the Reporting and Record-keeping Requirements (RRR) of the OEB.

2.6.2 APPLICATIONS

The Applications function manages regulatory applications and supports witnesses throughout regulatory proceedings. It provides services for a wide range of regulatory

matters, including distribution rate and transmission revenue requirement applications, transmission leave-to-construct applications, and applications related to mergers, acquisitions, amalgamations, divestitures, and area and system supply planning

2.6.3 PRICING AND LOAD FORECASTING

The pricing function provides pricing and cost allocation analysis and support for rate applications. This work entails developing rates for transmission and distribution tariffs and supporting the preparation and defense of rate proposals. The function also assists with the implementation of approved transmission and distribution rates.

The load forecasting function provides load forecasts to enable system planning and financial planning which underpin Hydro One's financial forecasts. The function provides load forecast data including the capture of conservation and demand management impacts, and embedded generation. This function also provides analytical support and load research analysis for a number of the Company’s business units.

2.6.4 OEB / OTHER COSTS

OEB/Other costs include the external costs associated with applications filed with regulatory bodies. Specifically, these costs stem from the provision of notice, stakeholder and consultation activities, provision of expert studies and witnesses, hearing-related expenses, intervenor cost awards, and miscellaneous items. Over the 2023-2027 period, Hydro One anticipates filing one major revenue requirement application for Distribution and Transmission, several facility applications, filings related to real estate and regional planning efforts and several smaller regulatory applications (B2M, NRLP, HOSSM, Remotes).

The OEB/Other costs also include Hydro One’s share of the OEB’s costs, including expenses related to the OEB’s quarterly assessments, proceedings and intervenor cost awards, and regulatory license assessments. Under the *Ontario Energy Board Act, 1998*, the OEB is required to recover all of its annual operating costs. Almost all of its costs are recovered from gas and electricity distributors and electricity transmitters. A small fraction

of OEB costs are recovered from the IESO and Ontario Power Generation and from licensing fees and penalties. OEB costs that are subject to recovery include expenses related to staff, office space, administration and overheads. Hydro One's share of these OEB costs is derived from the allocations to electricity distribution and transmission.

2.7 SECURITY MANAGEMENT

The Security Management function provides enterprise leadership, governance, risk oversight, policy, standards, assurance, and incident preparedness across cybersecurity, personnel security, physical security, and NERC compliance. It establishes the security standards and requirements that operating programs must meet, oversees enterprise security risk and third-party security risk, coordinates incident and recovery planning, and provides assurance that security controls remain appropriate and effective. Activities include overseeing Hydro One’s enterprise security operating model and coordinating security requirements across the company providing advice, coordination and solutions to achieve security standards. This ultimately supports the reliable delivery of electricity, protection of Hydro One’s assets, and the continuity or recovery of business functions in the event of a cyber or physical security incident.

The Security Management program is continuously enhanced with new capabilities that are required to meet the following requirements:

- To remain appropriately positioned against an evolving threat landscape that is increasing in complexity and sophistication. This requires Hydro One to augment and deploy new protective technologies and processes to safeguard assets;
- To meet increasing regulatory and legislative requirements, which in turn, drive the need for additional security capabilities and compliance requirements;
- To meet the increasing expectations of customers and stakeholders that entrust Hydro One to safeguard their sensitive information; and
- To manage the risks associated with third party software integrity, vendor personnel security management and third-party connectivity into Hydro One’s systems.

Table 11 presents the details of Hydro One's total Security Management costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 11 - Summary of Allocated Security Management Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Security Management Costs	**8.9**	**7.9**	**7.5**	**9.0**	**9.2**	**9.2**
Allocated to Transmission	4.3	3.8	3.6	4.8	4.8	5.0
Allocated to Distribution	4.5	4.0	3.6	4.1	4.2	3.9
Allocated to HOSSM	0.0*	0.0*	0.0*	0.0*	0.0*	0.1
Other	0.1	0.1	0.2	0.1	0.1	0.1

**Values less than $50k.*

The 2028 test year expenditure for Security Management is $9.2M, a $0.3M increase over 2023 actuals, and a $0.7M increase above average annual expenditures during the 2023-2027 period.

The increase in Security Management costs is below the rate of inflation over the 2023-2027 rate period, reflecting Hydro One's efforts to manage costs while maintaining the capabilities required to meet its security requirements. The reduction from 2023 to 2025 is primarily due to organizational restructuring impacting labour and administrative costs. The restructuring of Security Management contributed to maintaining a 1% Compound Annual Growth Rate between 2023 and 2027. Security Management costs are forecast to return to 2023 levels for 2026 to 2028, reflecting the required increased program oversight corresponding to the growing volumes of security events, as well as the expanded monitoring of digital and physical assets. Further details are provided in Exhibit E-04-04, Section 2.4.2.

2.8 INTERNAL AUDIT

Internal Audit Services supports Hydro One in achieving its strategic objectives and mission of energizing life for the people and communities of Ontario by employing a systematic, disciplined, and risk-based approach to evaluate and improve the effectiveness of governance, risk management, and internal control processes. The Internal Audit group reports on a functional basis to the Audit Committee of the Board of Directors and administratively to the CFO. It provides independent and objective assurance and consulting services designed to add value by improving Hydro One's processes and controls, and supporting operations. The group's mandate is to provide independent assurance to management of the Company and to the Board of Directors that internal controls are designed and operating effectively in areas of material business risk, both financial and non-financial, (including but not limited to Financial Reporting Integrity; IT/OT Governance & Cyber Security; Operational Excellence and Capital Portfolio Delivery) and to follow-up and report on timeliness and effectiveness of management actions to address findings from past audits.

In addition, Internal Audit Services function has responsibility for Management's NI 52-109 internal control certification program and performs independent testing of internal controls to support external certifications and related disclosures required under Canadian Securities legislation.

Hydro One's Enterprise Risk Management (Risk) function supports the successful execution of the company's strategy by aligning risk management activities with corporate objectives, providing stakeholders visibility into the risk environment, and enabling effective responses to a rapidly changing risk landscape through established frameworks and industry best practices. The Risk team facilitates an annual enterprise risk assessment identifying and assessing the principal enterprise risks within the risk universe "Results of the annual enterprise risk assessment are used to assist in management's decision-making, prioritization and allocation of resources. In addition, the annual enterprise risk assessment is used as an input into the internal audit planning process.

Table 12 presents the details of Hydro One's total Internal Audit, Enterprise Risk and Internal Control Certification and compliance costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 12 - Summary of Allocated Internal Audit Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Internal Audit Costs	**9.3**	**8.9**	**7.8**	**8.5**	**8.5**	**9.1**
Allocated to Transmission	4.5	3.9	3.4	3.4	3.4	3.9
Allocated to Distribution	4.7	4.3	3.5	4.3	4.3	4.0
Allocated to HOSSM	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.1	0.6	0.8	0.8	0.8	1.1

The E Source benchmarking study, provided as Attachment 1 to this Exhibit, includes Hydro One's Internal Audit costs as part of Finance, which has been benchmarked below first quartile compared to its peer group.

The 2028 test year expenditure for Internal Audit is $9.1M, a $0.2M decrease from 2023 actuals, and a $0.5M increase above average annual expenditures during the 2023-2027 period. Internal Audit and internal control and compliance costs declined from $9.3M in 2023 to $7.8M in 2025, reflecting organizational efficiencies implemented across this function, and are forecasted to remain relatively stable through the 2027 bridge year. Internal audit costs increase to $9.1M in the 2028 test year to support Hydro One's expanding audit program, including additional cybersecurity-related audit activities and internal control and design efforts associated with the implementation of SAP S/4 HANA as well as enhancements to the Internal Controls and Compliance function to strengthen reporting, disclosure, and regulatory compliance oversight.

2.9 FACILITIES AND REAL ESTATE

The Facilities and Real Estate function supports the reliable operation of Hydro One's business by providing land management, workplace accommodation, facilities

management, and real estate services necessary to execute operating, maintenance, and capital work programs.

Table 13 presents the details of Hydro One's total Facilities and Real Estate related OM&A costs and their allocation to Hydro One Transmission, Hydro One Distribution, and other business segments and affiliates.

Table 13 - Summary of Allocated Facilities and Real Estate Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Real Estate	9.7	9.6	8.1	10.2	10.1	11.3
Facilities	59.3	61.3	57.0	54.1	54.5	69.6
Total Facilities and Real Estate Costs	**69.0**	**70.9**	**65.1**	**64.3**	**64.7**	**80.9**
Allocated to Transmission	36.4	36.3	33.5	34.3	34.3	39.6
Allocated to Distribution	32.5	34.2	31.5	29.6	30.0	40.8
Allocated to HOSSM	0.0	0.0	0.0	0.0	0.0	0.0
Other	0.0	0.3	0.1	0.3	0.3	0.5

The E Source benchmarking study provided as Attachment 1 to this Exhibit benchmarked Hydro One's Real Estate costs below first quartile levels relative to its peer group, indicating that Hydro One's Real Estate function compares favourably with comparable utilities.

The 2028 test year expenditure for Facilities & Real Estate is $80.9M, an $11.9M increase over 2023 actuals, and a $14.1M increase above average annual expenditures during the 2023-2027 period. The step increase in 2028 is primarily attributable to higher facilities-related costs associated with Hydro One's growing operational footprint, lease renewals, inflationary pressures on facility operating expenses, and the addition of new and expanded facilities required to support workforce growth and operational requirements associated with Hydro One's capital investment and business growth plans.

2.9.1 REAL ESTATE: LAND ACQUISITION AND MANAGEMENT

The Land Acquisition and Management function acquires, manages, protects, and optimizes the real estate assets and property rights required to support Hydro One's transmission and distribution systems. The function enables the delivery of capital infrastructure programs, manages Hydro One's land rights portfolio and stakeholder relationships, administers revenue-generating land use programs, supports Indigenous land matters, and provides specialized real estate and property-related advisory services that support Hydro One's operational, regulatory, and business objectives.

Land Acquisition and Management is accountable for:

- Supporting Hydro One's capital and sustainment programs by acquiring and securing easements, permits, licences, road access rights, and other property interests required for transmission and distribution infrastructure; supporting environmental assessments, project approvals, Indigenous consultation activities, and regulatory filings; and securing the property rights necessary for the safe and reliable operation of Hydro One's assets.
- Managing and protecting Hydro One's extensive land rights portfolio, including more than 200,000 acres of transmission corridors, station lands, and other real estate assets across Ontario. This includes maintaining relationships with landowners and stakeholders, administering more than 800,000 property and land rights records (including over 400,000 unregistered low-voltage rights agreements), overseeing property information systems and land rights research, and resolving title, ownership, and property record issues.
- Administering Secondary Land Use programs supporting the generation of external revenues that offset Hydro One's revenue requirement (D-02-01); managing commercial leases, Crown Land Use Permits, operational agreements, and third-party land use arrangements; and generating external revenues that help offset Hydro One's revenue requirement.
- Managing Indigenous land rights and community relationships by securing and administering permits, access agreements, property rights, annual rental arrangements, and other land-related agreements associated with transmission

and distribution infrastructure. This includes supporting consultation, engagement, accommodation, and negotiation activities that enable ongoing operations and future infrastructure development.

- Providing specialized real estate and property advisory services, including support for corporate transactions, due diligence, property valuations, litigation matters, land rights research, negotiations, and the resolution of encroachments, access issues, landowner disputes, damage claims, right-of-way concerns, and other property-related matters.

2.9.2 FACILITIES

The Facilities work program addresses all aspects of Company workspace and building requirements. This involves managing Company-owned facilities and a portfolio of leased facilities as well as overseeing the construction of new facilities. The work program focuses on maintaining existing assets and ensuring compliance with laws and applicable codes.

The Facilities function is accountable for:

- The Management of approximately 50 contract lease agreements for workspace rented from other parties, including renewals and contractual obligations undertaken regarding payment of rent, operating expenses, and taxes;
- Coordination of activities related to the ongoing management, operation, maintenance, and inspection of approximately 1,500 buildings across 500 sites (including Operational Centres/Administrative Facilities and TS Facilities[3]); and
- Developing accommodation strategies and acquiring new employee/trades workspace in line with operational requirements.

Facilities categorizes its OM&A spending into four broad categories: 1) preventive maintenance, 2) corrective maintenance, 3) scheduled maintenance, and 4) administrative and operational expenses. These spending categories are further

[3] OM&A spending on operational and maintenance activities for TS Facilities are described in Exhibit E-02-02 Section 2.2.9.1.

described in GSP Section 4.8.4.2. This program supports funding for these spending categories and the associated labour costs for the common facilities.

Facilities costs are largely driven by space needs which are determined by Hydro One's work programs, business and regulatory requirements. A significant portion of the workload needs are met by engaging the strategic outsourced service provider as described in GSP Section 4.10.3.2.

The largest components of Facilities common OM&A expenditures are lease costs and administrative and operational expenses, which together comprise nearly 40% of total Facilities and Real Estate common OM&A expenditures.

The Facilities OM&A increase is driven by fixed-cost contractual obligations, which arise primarily through lease agreements. For example, rent, operating and tax costs are fixed by lease agreements. Other costs are set by Hydro One's contracts with service providers for facility maintenance and other services. Fixed facility costs, including utilities and other operating expenses, are expected to continue increasing, in line with industry trends.

The 2028 Facilities OM&A increase also reflects the restoration of the preventative maintenance programs that were scaled back during the 2023-2027 period as available funding was prioritized toward corrective maintenance and emergency repairs. Restoring these programs is necessary to address recurring lifecycle-based maintenance requirements and support the ongoing reliability and condition of Hydro One's facilities.

3.0 OTHER OM&A

Other OM&A is comprised of credits (offsets to OM&A) associated with capitalized overhead, environmental provision, as well as the non-service cost component of OPEB and other costs. These are listed in Table 14.

Table 14 - Summary of Other OM&A ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Capitalized Overhead	-203.3	-232.7	-238.1	-229.9	-230.8	-345.7
Non-Service Costs Component of OPEB	73.4	48.7	57.4	52.6	57.4	65.5
Environmental Provision	-27.4	-9.0	-1.7	-0.9	-0.9	-0.7
Other	14.6	43.1	-4.4	-50.1	-72.0	-10.1
Total Other OM&A	**-142.7**	**-149.9**	**-186.8**	**-228.3**	**-246.3**	**-291.0**
Allocated to Transmission	-78.4	-94.9	-112.4	-104.4	-101.3	-160.3
Allocated to Distribution	-68.7	-59.0	-80.7	-123.9	-145.0	-130.7
Allocated to Other[4]	4.4	4.0	6.2	0.0	0.0	0.0

The lower OM&A amount in the 2028 Test Year reflects an increase in overheads capitalized arising from the application of the updated Atrium Study methodology presented in Exhibit E-04-08-01. The revised study results increased the proportion of overhead costs allocated to capital activities, resulting in a corresponding reduction in OM&A. This reduction is partially offset by the cessation of cost containment measures reflected within the Other OM&A category in 2026 and 2027.

3.1 CAPITALIZED OVERHEAD CREDIT

Capitalized overheads represent the portion of allocated and/or business unit functions and services that support capital work. These costs are included in Common Corporate services and the budgets of other lines of business. OM&A expenses are thus reduced by the capitalized amounts.

Capitalized overhead costs are charged to capital work based on a capital overhead rate derived from the allocation and capitalization study performed by Atrium, as described in Exhibit C-08-02. Generally speaking, all else equal as the capital work program increases, more overheads are capitalized and less are expensed as OM&A. The change in OM&A

[4] Allocated to Other primarily reflects high-level journal entry transfers related to system-generated allocations from Transmission and Distribution to Shareholders.

in the test year in relation to the change in capitalized overhead costs for Transmission and Distribution is shown in Table 14 above, and Appendix 2-D at Attachment 1 of Exhibit C-08-02.

3.2 NON-SERVICE COST COMPONENT OF OPEB

The non-service cost component of OPEB reflects the OM&A impact of the OEB's decision in the 2020-2022 Transmission rate application (EB-2019-0082). The corresponding increase in Distribution OM&A was recognized beginning in 2023, as the decision was issued during the 2018-2022 Distribution rate period.

3.3 ENVIRONMENTAL PROVISION

In 2001, Hydro One first recognized a liability on its balance sheet representing the present value of estimated future environmental expenditures required to address risks associated with two legacy environmental matters inherited from Ontario Hydro. These obligations related to the management of polychlorinated biphenyl (PCB) contamination and the remediation of chemically contaminated properties, referred to as the Land Assessment and Remediation (LAR) program.

Since the initial recognition of these liabilities, Hydro One has continued to execute its environmental remediation programs. Although remediation of the PCB contamination on affected equipment is expected to be completed by the end of 2026, the environmental provision continues to reflect expenditures and liability adjustments associated primarily with the ongoing LAR program. In determining the environmental liability balance, Hydro One estimates the current cost of completing the required work and applies assumptions regarding the timing of future expenditures to develop the associated future cash flow projections.

Future expenditures are required to inspect, test and remediate the contamination. Environmental work is initially recognized in the Sustainment OM&A work program and is detailed in Exhibit E-02-02 for Transmission, and in Exhibit E-03-02 for Distribution. The amount is then removed from OM&A as the costs are charged to the balance sheet

provision. The offsetting environmental regulatory asset is amortized based on the pattern of expenditure. Refer to Exhibit D-01-01 for the proposed treatment of future expenditures in revenue requirement for 2028-2032 related to these expenditures.

3.4 OTHER COSTS

Other Costs include adjustments to provisions, vacation reserves, inventory adjustments, project write-offs, Gregorian or fiscal calendar adjustments, and indirect depreciation adjustments related to the reclassification of the depreciation component embedded in Transportation and Work Equipment (TWE) charges from OM&A to depreciation expense to avoid double counting.

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FINAL Report

Hydro One Networks Inc.

Common Corporate Cost Comparative Study

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June 2026

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EXECUTIVE SUMMARY

Hydro One Networks Inc. ("HONI") engaged E Source to refresh the common corporate cost benchmarking analysis originally conducted in 2020 by UMS Group Inc., which has since been acquired by E Source. The study evaluates common corporate functions that are centralized and shared across HONI's Transmission and Distribution businesses, as well as certain affiliated entities.

The objective of the engagement was to replicate the comparative metrics and analytical framework established in the original study using updated cost and operational data. By maintaining consistency with the prior methodology, the refreshed analysis provides an updated view of HONI's relative performance while preserving comparability with the earlier benchmark.

This report discusses the approach used in executing the benchmarking including the metrics chosen, the selection of the comparator group utilities, and the collection and analysis of data used for the benchmarking. This study presents and interprets benchmarking data from HONI and the comparator group. It also provides insights into the relative level of HONI's common corporate costs by function, and where appropriate, discusses potential drivers of cost differences.

The overall finding from the benchmark is that HONI's common corporate costs are very competitive compared with the comparator group. Of the nine functions benchmarked, four are at or near 1st Quartile levels, four are at or near Median levels and one is near 3rd Quartile levels.

Report Outline

The ensuing report is divided into several sections as described below:

- Section I – Introduction: A high-level description of the objective and approach for the study.
- Section II – Project Approach: A description of the process and rationale for scope determination, data collection, normalisation of data, and comparator group selection.
- Section III – Study Results: A discussion of findings and conclusions around the common corporate cost functions benchmarked.
- Appendix A: A description of E Source's qualifications.

SECTION I – INTRODUCTION

Hydro One Networks Inc. ("HONI") has undertaken benchmarking initiatives to better understand the efficiency and performance of both operational programs and centralized corporate functions that support its Transmission and Distribution businesses. Building on earlier benchmarking work conducted in 2020, the company continues to evaluate these common corporate services to ensure that their costs and performance remain aligned with industry peers and evolving organizational needs.

Objective

The objective of the study was to refresh and update the benchmarking analysis of HONI's common corporate costs using the analytical framework originally developed in the 2020 study conducted by UMS Group Inc., which has since been acquired by E Source. By maintaining consistency with the original methodology, the refreshed analysis enables HONI to evaluate its current performance relative to an appropriate peer group of utilities while preserving comparability with the prior study.

Consistent with the approach established in the original analysis, the study was undertaken using the following parameters:

- Apply the previously defined scope of information and functional cost categories used in the original benchmarking study.
- Utilize the established comparator peer group framework to evaluate HONI's common corporate costs relative to comparable utilities.
- Maintain the normalisation methodology developed in the original study to ensure consistent scaling of costs across utilities of different sizes and operating models.
- Apply consistent cost definitions across the comparator utilities to ensure a common understanding of the functional costs being evaluated.
- Measure and assess HONI's common corporate costs relative to the benchmark utilities using the same analytical framework employed in the prior study.

SECTION II – PROJECT APPROACH

E Source implemented the following project approach to benchmark HONI's 2024 common corporate costs and evaluate them against those of comparator utilities. The analysis uses 2024 costs as they represent the most recent full year of actual cost data available. The benchmark itself was primarily quantitative, with minimal adjustments made to HONI or comparator cost data. Where differences were observed, the analysis focused on identifying the factors most likely driving those quantitative variances.

This study applies the benchmarking framework originally developed for the 2020 common corporate cost benchmarking analysis conducted by UMS Group Inc., which has since been acquired by E Source. That study established the scope of functions evaluated, the comparator peer group structure, and the normalization methodology used to support meaningful comparisons across utilities.

The objective of the current engagement was to replicate that analytical framework using updated cost and operational data. Maintaining consistency with the original methodology ensures that results remain comparable over time and enables HONI to assess changes in performance relative to both historical results and industry peers.

The benchmarking framework evaluates common corporate functions that provide centralized services across HONI's Transmission and Distribution businesses. These functions represent shared administrative and strategic activities that support the organization as a whole.

To support the analysis, E Source leveraged the benchmarking information and database originally developed through UMS benchmarking studies and engagements, which has continued following the acquisition of UMS by E Source. Updated data was collected from comparator utilities as needed to refresh and supplement the database for purposes of the study.

In selecting the comparator group, E Source identified utilities with operational characteristics broadly similar to HONI in terms of size, organizational structure, and service territory. Utilities from both Canada and the United States were considered in order to establish a sufficiently broad and relevant comparison group.

The cost components for each common corporate function and the final comparator group composition were reviewed and confirmed with HONI to ensure the benchmarking framework appropriately reflected HONI's organizational structure and the intended scope of the analysis.

The following sections describe the key elements of the approach - including scope determination, comparator selection, normalization methodology, and data collection and validation - and explain how these elements contribute to producing an objective and relevant benchmark.

Scope Determination

The scope of functions evaluated in this study mirrors the functional structure defined in the 2020 benchmarking analysis. These functions include corporate management, finance, human resources, legal, regulatory affairs, real estate services, corporate affairs, asset management

planning, and system operations support. Each function represents activities that are centralized within the organization and whose costs are shared across business units.

Comparator Selection

In order to execute the benchmarking, a comparator group of Canadian and U.S. utilities was developed focused on those who had both Transmission and Distribution, were of comparable size as HONI, and/or had a more rural territory in terms of distribution customers per square kilometre. To ensure an adequate number of comparators, utilities were also included, for which E Source already had recent common corporate cost data and were viewed as reasonably comparable.

Finally, another Ontario utility was included in the comparator group even though it is municipally owned and distribution-only. While it is not necessarily considered a strong comparator for all common corporate functions, it was viewed as important to include a local utility which operates under similar legal and regulatory conditions.

Initially, 28 potential comparators were approached to participate in the study. From these, 14 agreed to participate. The resulting comparator group represents a reasonable and acceptable comparison group for HONI.

The comparator group for the refreshed study was generally consistent with the comparator group used in the original 2020 analysis. Where participation differed from the original study, comparable utilities with similar operational characteristics were included where appropriate to maintain a sufficiently broad and representative peer group.

Table 1: Comparator Group

Utility	Electric Functions
AES Indiana	Generation, Transmission, Distribution
ATCO Electric	Transmission, Distribution
ENMAX	Generation, Transmission, Distribution
EPCOR	Transmission, Distribution
El Paso Electric	Generation, Transmission, Distribution
NB Power	Generation, Transmission, Distribution
NV Energy	Transmission, Distribution
PG&E	Transmission, Distribution
PSEG LI	Transmission, Distribution
Santee Cooper	Generation, Transmission, Distribution
Southern California Edison	Generation, Transmission, Distribution
SDG&E	Transmission, Distribution
Toronto Hydro	Distribution

Utility	Electric Functions
Yukon Energy	Generation, Transmission

Normalisation Factor Development

Consistent with the original benchmarking framework, cost comparisons were normalised using factors aligned with the primary drivers of cost for each function. These normalisation factors enable meaningful comparisons between utilities of different sizes and organizational structures by scaling costs relative to the level of activity supported by each function. Examples of normalisation factors include revenue, number of employees, customer counts, asset base, and network size, depending on the function being evaluated.

Note: To ensure all costs were accounted for, and for peer comparability, revenue normalization figures include all revenue collected by the utility, including cost of power.

Table 2: Normalisation Factors

Function	Normaliser	Reason for Normaliser Selection
Corporate Management	Revenue	Representative of key drivers - Costs are typically driven by size and complexity for which revenue is a proxy.
Finance	Revenue	Representative of key drivers - Costs are typically driven by the amount of financial activity for which revenue is a proxy.
Real Estate	Employees	Representative of key drivers - Costs are typically driven by quantity of facility and land assets for which number of employees is a proxy.
Human Resources	Employees	Direct driver - Costs are typically driven by the number of employees.
Legal	Revenue	Representative of key drivers - Costs are typically driven by size and complexity for which revenue is a proxy.
Regulatory Affairs	Revenue	Representative of key drivers - Costs are typically driven by size, complexity, and regulatory environment for which revenue is a proxy.
Asset Management Planning	Net Asset Base	Direct driver - Costs are typically driven by size of the asset base.
Corporate Affairs	Customers	Representative of key drivers - Costs are typically driven by the amount of customer outreach for which number of customers is a proxy.

Function	Normaliser	Reason for Normaliser Selection
System Operations	Circuit Kilometres	Direct driver - Cost differences are typically driven by the number of circuits.

Design Review

As this study represents a refresh of the 2020 benchmarking analysis and applies the same established framework, a formal design review stage was not required. The scope of functions, comparator group structure, and normalization methodology had already been defined and validated as part of the original study.

Data Collection and Validation

A data collection template was created to assist both HONI and the comparator utilities in providing data. This data comprised both demographic and cost data.

Table 3: Demographic Data Collected

Number of Distribution Customers
Number of Employees
Annual Revenue
T&D Asset Base (net)
T&D Circuit Kilometres (or Miles)

Table 4: Cost Information Collected

Corporate Management Costs	Legal Costs
Finance Costs	Regulatory Affairs Costs
Real Estate Costs	Asset Management Planning Costs
Human Resources Costs	Corporate Affairs Costs
System Operations Costs	

For HONI, the costs benchmarked reflect the common corporate costs for each respective function. However, the same may not be true for all of the comparator group utilities as the costs for some of these functions may be spread between different lines of business. In these cases, comparable costs were collected regardless of where in the organization they occurred.

For HONI and each comparator utility, the cost data was collected along with the demographic data for the normalisers. For U.S. companies, costs were converted to CAD at an exchange rate of USD:CAD = 1.37[1] and miles were converted to kilometres. If comments submitted by

[1] Source: U.S. Internal Revenue Service annual average currency exchange rates for tax year 2024.

comparators indicated that non-typical costs were included in a function, E Source requested that these non-typical costs be removed and the utility's benchmark submission be revised appropriately. Where necessary, costs were moved between functions within individual comparator utilities to align with the group as a whole, based on where most utilities collected those costs.

There were several cost "buckets" that needed to be moved for HONI (and some comparator utilities if appropriate) in order to align costs across functions. These were as follows:

- Strategy and Innovation costs were moved from Asset Management Planning to Corporate Management.
- CFO's Office costs were moved from Finance to Corporate Management.
- HR Pay Service costs were moved from Finance to Human Resources.
- Regulator assessments for fees and allocated costs were removed from Regulatory Affairs costs for all utilities which included them.
- Indigenous Partnerships & Business Development costs were included in Corporate Affairs.
- Real Estate costs were removed from Finance and benchmarked separately.
- Property Insurance for Equipment (e.g., Transformers) common corporate costs were removed from all utilities' costs.

Not all of the comparator utilities provided data for all of the functions. In those circumstances where a utility did not, this was because it did not operate that function as a common corporate service and was unable to adequately collect the relevant costs from the different functions in which they were incurred to provide a set of comparable costs.

SECTION III – STUDY RESULTS

Overall, the HONI common corporate costs benchmarked compare well to the comparator group. Of the nine functions benchmarked, four are at or near 1st Quartile levels, four are at or near Median levels and one is near 3rd Quartile levels

It should be noted that the HONI common corporate costs benchmarked are *pre-allocation costs*; therefore, some of them are borne by HONI entities other than Transmission and Distribution, so not all of them go into T&D rates. This approach was selected because allocation methods vary significantly between utilities. Conducting the analysis on a post-allocation basis would require reversing those allocations to enable meaningful comparisons. Using pre-allocation costs therefore provides a more consistent basis for benchmarking and represents a conservative comparison because not all of these costs are ultimately recovered through Transmission and Distribution rates. Similar data was collected from peers, i.e., common corporate cost level, not business unit allocation level.

In addition, investor costs (i.e., those which are borne by shareholders, rather than customers) are also included in the HONI and peer benchmark numbers. Therefore, the results shown in Table 5 below should not be considered as a complete representation of comparative position without an understanding of the related analysis for each function.

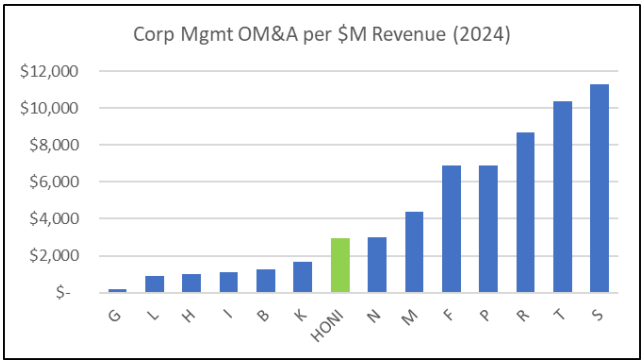
Table 5: Summary of Benchmark Results (2024 Costs)

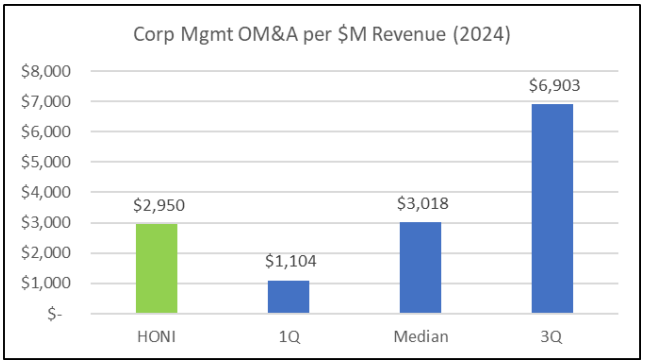
Cost Category	Normaliser	HONI KPI | Quartile	1st Quartile	Median	3rd Quartile
Corporate Management	$M of Revenue	$ 2,950 | 2nd	$ 1,104	$ 3,018	$ 6,903
Finance	$M of Revenue	$ 3,943 | 1st	$ 5,501	$ 8,096	$ 12,810
Real Estate	# of Employees	$ 1,056 | 1st	$ 1,278	$ 3,244	$ 6,077
Human Resources	# of Employees	$ 4,116 | 2nd	$ 2,767	$ 3,871	$ 5,470
Legal	$M of Revenue	$ 1,628 | 1st	$ 2,913	$ 3,625	$ 4,996
Regulatory Affairs	$M of Revenue	$ 2,925 | 2nd	$ 1,660	$ 3,015	$ 4,173
AM Planning	$M of Net T&D Assets	$ 1,962 | 1st	$ 1,236	$ 3,075	$ 5,512
Corporate Affairs	# of Customers	$ 13.2 | 3rd	$ 4.7	$ 9.3	$ 12.3
System Operations	Circuit kM	$ 386 | 2nd	$ 180	$ 476	$ 927

Corporate Management

HONI's 2024 Corporate Management costs per $million of revenue are slightly below the Median level. These costs are pre-allocation and most of the costs are not recovered from ratepayers.

Figure 1: Corporate Management Costs



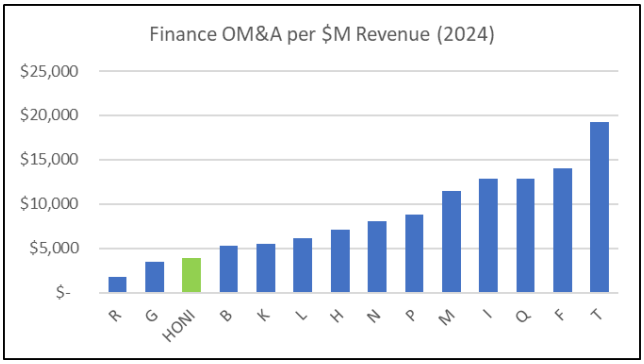


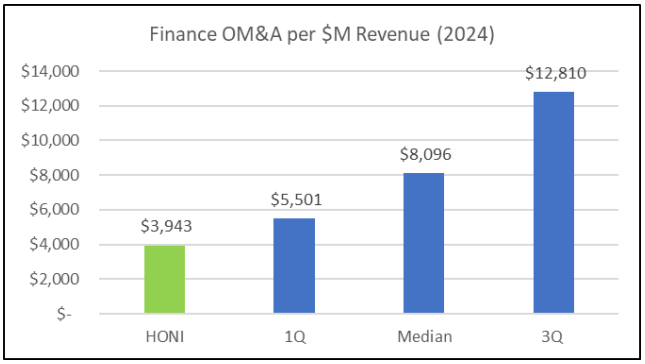
Note: Corporate Management costs include those related to overall company direction, rather than specific company business functions – Board of Directors, Chairman's Office, CEO's Office, President's Office, COO's Office, Strategy and Innovation, Ombudsman's Office, etc.

Finance

HONI's Finance costs per $million of revenue are slightly below 1st Quartile levels.

Figure 2: Finance Costs



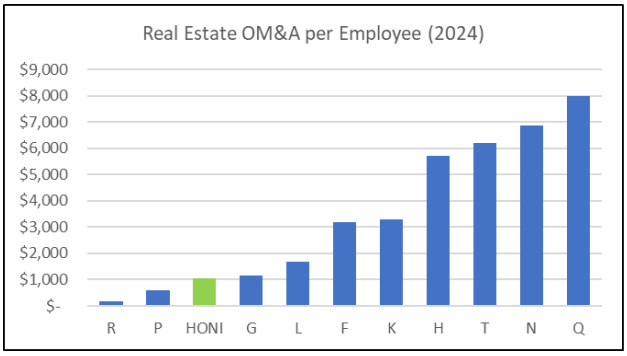


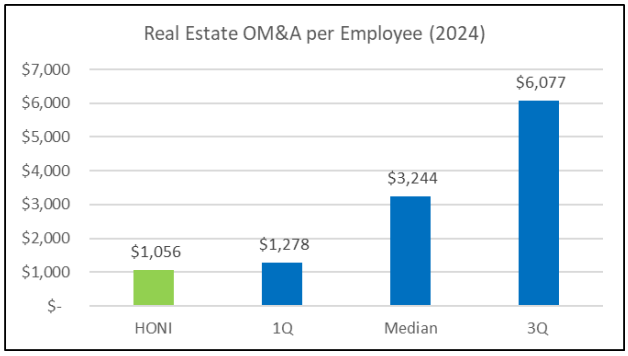
Note: Finance costs are those which provide strategic advice and services related to planning, processing, recording, reporting and monitoring of financial transactions – Controller Services, Treasury, Tax, Audit, Insurance, Business Planning, and Risk Management.

Real Estate

HONI's Real Estate costs per Employee are slightly below the 1st Quartile level.

Figure 3: Real Estate Costs



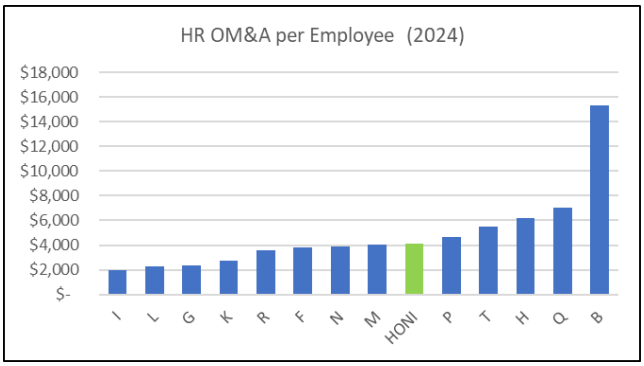


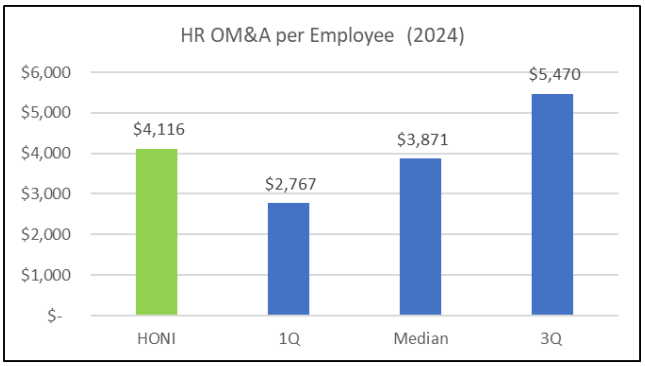
Note: Real Estate costs are those associated with providing functions related to managing land rights and services related to managing property.

Human Resources

HONI's Human Resources costs per employee are slightly above the Median level.

Figure 4: Human Resources Costs



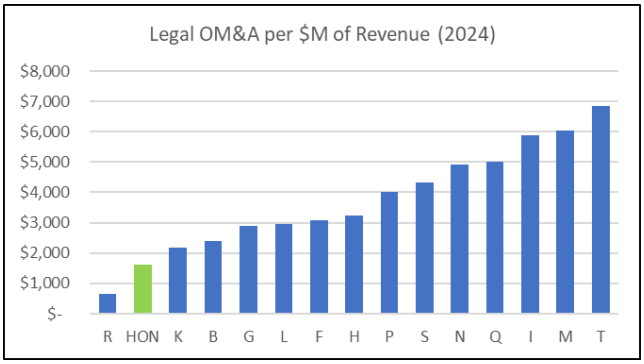


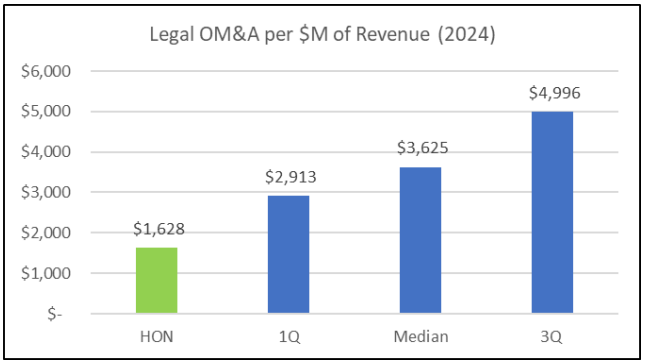
Note: Human Resources costs are those related to the policies, systems, and programs to attract, manage, engage, and retain a workforce to execute business strategy – recruiting and development, HR Services, health and wellness, diversity, employee and labor relations, and payroll management.

Legal

HONI's Legal costs per $million of revenue are slightly below the 1st Quartile level.

Figure 5: Legal Costs



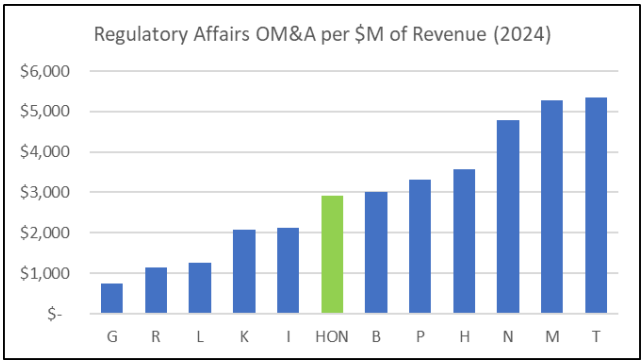


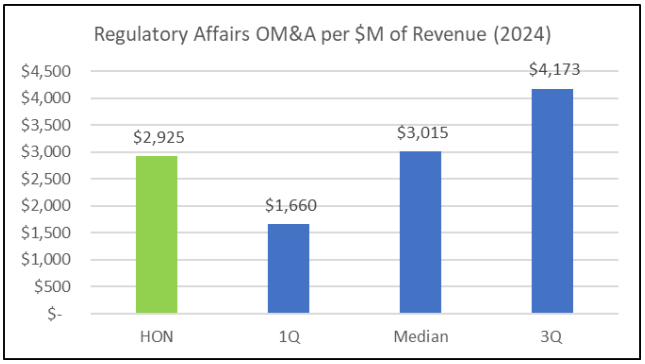
Note: Legal costs are those which ensure compliance with law, provide legal services, and provide corporate secretariat services.

Regulatory Affairs

HONI's Regulatory Affairs costs per $million of revenue are at the median level.

Figure 6: Regulatory Affairs Costs



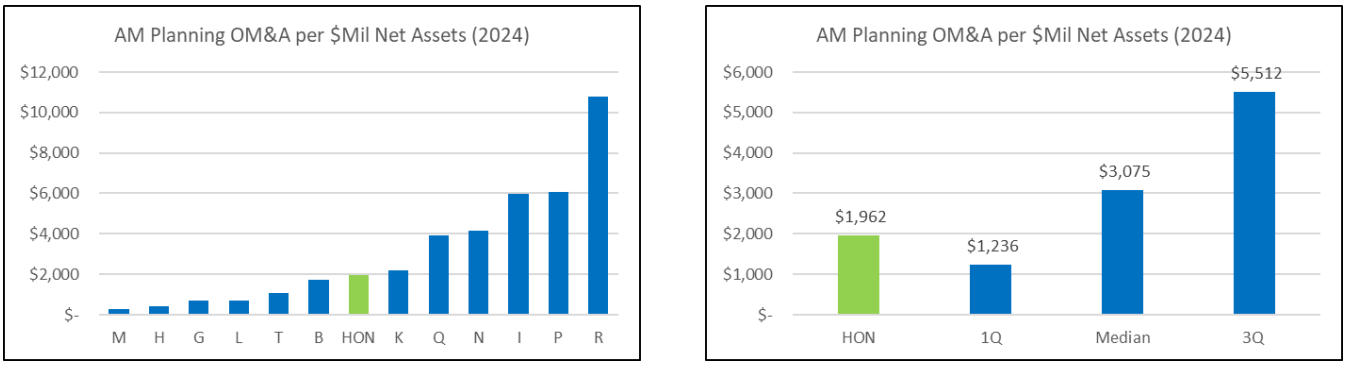


Note: Regulatory Affairs costs are those associated with dealings with regulatory bodies including the utility commission, Federal regulator, etc., as well as development of regulatory strategy and coordination of submissions. User fees or other assessments by Regulators to fund their operations are not included.

Asset Management Planning

HONI's Asset Management Planning costs per $million of Net Assets are slightly above the 1st Quartile level.

Figure 7: Asset Management Planning Costs

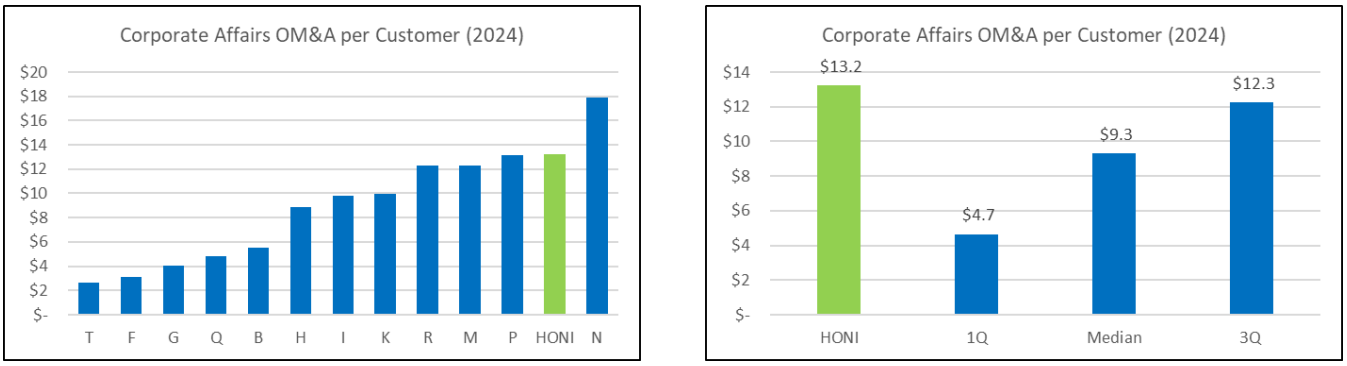


Note: Asset Management Planning costs include those to develop the investment plan, manage investment strategies, scope network expansions and new or modified customer connections, and undertake the asset management of transmission and distribution assets.

Corporate Affairs

HONI's Corporate Affairs costs per Customer are slightly above the 3rd Quartile level. HONI has a robust Indigenous Partnerships & Business Development function which many of the comparator group members do not. Removing these costs would reduce HONI's normalised cost closer to Median levels (~$10/customer). However, spending on Indigenous Partnerships has been identified as a strategic priority by HONI to support meaningful and long-term relationships with Indigenous partners.

Figure 8: Corporate Affairs Costs

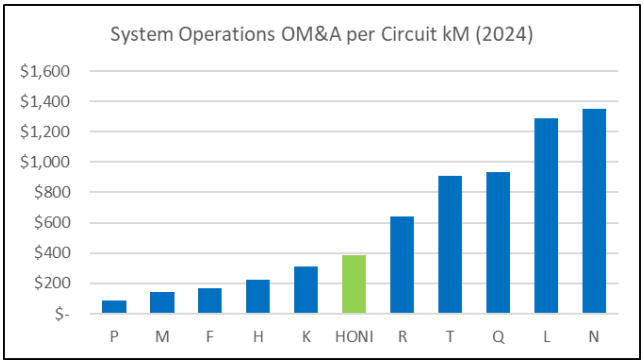


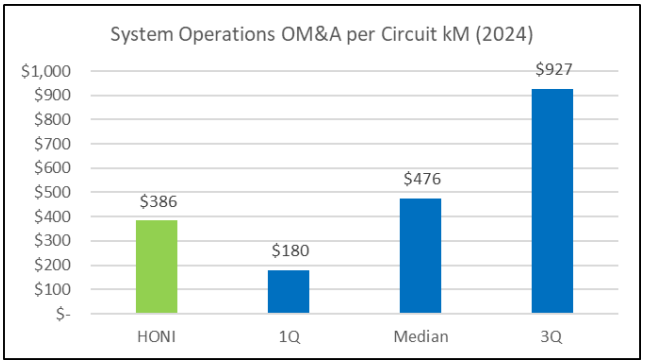
Note: Corporate Affairs costs include those associated with communicating to stakeholders other than Investors – government affairs, public affairs, Indigenous Partnerships and Business Development.

System Operations

HONI's System Operations costs per $million of revenue are slightly below the Median level.

Figure 9: System Operations Costs





Note: System Operations costs are associated with supporting the coordination and dispatch of crews as required, planning for and reacting to system contingencies, scheduling and coordinating planned outages, providing customer notifications, and monitoring and reporting on system performance.

APPENDIX A – E SOURCE QUALIFICATIONS

E Source, the acquirer of previously engaged UMS Group, delivers outcome-based consulting, data science, and research services exclusively for the utility industry. Since 1986, it has provided services on a variety of projects for more than 500 electric, natural gas, water, wastewater, and multi-service utility clients—helping to transform operations, enhance efficiency, and adapt to evolving industry demands. With a corporate commitment to practical innovation, we deliver nearly four decades of utility-focused service through a broad and unique range of capabilities within three core practices: Consulting (focused on utility transformation), Data Science (turning utility data into clear decisions), and Research and Advisory (including data-backed insights, benchmarking, and expert advice to assist utilities in optimizing performance, reducing risk, and seizing opportunities.

In integrating UMS Group into its organization, E Source adopts the position of the leading provider of utility benchmarking services, starting with UMS Group's initial Benchmarking and Best Practice Consortia in 1990 (PACE - Performance and Competitive Excellence), and its established position as a global leader in electric industry multi-company assessment and benchmarking studies. Key differentiators in our performance assessment approach are (1) the depth of our understanding of industry best practices to drive operational performance, and (2) benchmark programs that define current best practice productivity and service level performance in all major functional areas. Demonstrating the breadth of our experience, we have performed engagements on *six continents* with more than *300 companies*.

E Source's performance database developed and maintained over the past 36 years and its E Source-facilitated industry consortia of leading Generation, Transmission, and Distribution companies around the world provide significant insights into the drivers of best practices and resulting top quartile service and cost level performance.

Experience Summary of Project SME – Jeffrey W. Cummings

Mr. Cummings has over 45 years of professional consulting experience, with an extensive background in engineering, strategic and operational planning for vertically integrated investor-owned utilities and municipalities in North America and Asia Pacific. His most recent engagements include projects for Hydro Ottawa, Portland General Electric, Lansing Board of Water and Light, AES-Indianapolis Power and Light Company, Pacific Gas and Electric, FirstEnergy (Ohio, West Virginia, Maryland, New Jersey, and Pennsylvania), NIPSCO (Gas), ATCO Electric, Saskatchewan Power, Ameren (Illinois and Missouri), Ergon Energy, Toronto Hydro (THESL), and Public Service Electric and Gas Company. He has supported the industry in addressing (1) key strategic and operational challenges related to system modernization, (2) system cost and service level performance through comparative analyses (benchmarks) and the integration of industry best practices, (3) project and portfolio management, (4) reliability and risk mitigation, (5) energy efficiency, (6) fleet optimization, (7) capital investment planning and prioritization, (8) asset risk strategy and plan development, (9) organizational transformation, and (10) regulatory strategy. When called upon, he has offered expert testimony and/or opinion, most

recently for two Canadian Provincial Utilities, one Mideast Utility and for four US Investor-owned utilities operating in Kansas, New Jersey, Ohio, and Pennsylvania.

Earlier in his career, he held a series of engineering leadership positions at Vectra Technologies (formerly Pacific Nuclear and a publicly traded nuclear services company) and ultimately became Vice President of Nuclear Engineering. In that capacity, he served as the profit/loss manager for over 425 professional engineers across five regional offices in the U.S. In performing this role, he actively engaged in formulating strategies for customer development, product/service expansion, business consolidation, and oversaw the management of over 500 projects annually for approximately 75 percent of the U.S. nuclear utilities. Prior to his tenure with Vectra Technologies, Stone and Webster Engineering Corporation employed Mr. Cummings where he assumed increasing levels of responsibility in the management of large Lignite and Nuclear Power engineering and construction projects, culminating as Project Controls Manager for the completion of the last U.S. commercial nuclear power generating station (Clinton Power Station).

Mr. Cummings holds an M.S. degree in Operations Research from the U.S. Naval Postgraduate School and a B.S. degree from the U.S. Naval Academy at Annapolis, Maryland

Highlights of Directly Relevant Experience

Most recently supported the pre-commencement activities related to LUMA's takeover of the Puerto Rican Electric Power Authority (PREPA), conducting a gap assessment of its T&D Operations focused on Reliability, System Resiliency, Major Event Management, Asset and Work Management, Technical Services, Materials Management, and Fleet, supporting Regulatory in the development of the System Remediation Plan, and establishing the procedural / process infrastructure for its Asset Management function. Mr. Cummings provided oral testimony during the Technical Conferences leading up to Commencement and is currently assisting in the implementation of LUMA's Asset and Work Management Practices.

Assisted a Mid-Atlantic's Utility in its initiative to operationalize its Investment Delivery Assurance function in achieving two key outcomes: (1) Project and Work Execution to pre-established schedule, budget, and quality requirements and (2) verifying the extent to which any value and / or risk mitigation benefits ascribed to specific projects / programs are realized (indicative of capital investment and O&M spending portfolios that are or are not in alignment with Asset Management and Enterprise strategies – SAMP, AMPs, etc.).

- Project and Work Execution: Establishing priorities and coordinating activities among operations, maintenance, contractors and supporting functions, identifying and evaluating possible differences in productivity of outside contractors and in-house staff, inconsistencies in providing "as-built" drawings upon completion of a project, tendency to match workload to available staff rather than establish a staffing strategy based on system / asset requirements, management of project and schedule contingencies, post-project reviews, and barriers resulting from organizational silos during execution.

- Value and / or Risk Mitigation Realization: Determining and communicating the total impact of capital investment and O&M spending portfolios to all stakeholders. This

required an approach and supporting framework that calculates and aggregates projected benefits of an entire portfolio.

In support of a Canadian Utility's rate filing application, performed a Unit Costs Benchmarking Study aimed at reviewing how the utility determined the unit costs underlying its distribution system capital and operational programs, performing benchmarking comparisons with a selected peer group of utilities in Canada and the United States, and providing recommendations on how the utility can improve its unit costing practices in the future.

Supported development of an Northeastern Utility's 5-year Base Capital Budget, providing justification for each element, complete with detailed supporting analysis and benchmarks where needed and appropriate, quantifying the impact of planned Clause and Blanket spend, as well as specific named Capital projects on anticipated asset failure rates and the resulting need for spending of each Capital Blanket, challenging and testing the logic and rationale for options considered and choices made for spend levels proposed, and creating a coherent narrative to explain the reasons and justification for major amounts involved and variances from previous plans, helping the utility harness their historical data on costs, workload volume and unit rates to clarify assumptions regarding cost drivers behind projections of Capital Spend in each area for each year looking forward over the 5 years, and providing support in the design / development of a presentation of the 5-year Capital Budget for Executive Management review.

Supported the filing of a Midwest Utility's T&D Grid Modernization and Resiliency Plan, identifying and analyzing the rationale and wide-ranging implications of the Plan for the Company and its customers. Noting that the utility is committed to investing as wisely as possible on its customers' behalf, the final report provides transparency to the proposed investments and decisions driving their selection, quantifying the benefits (most notably those pertaining to reliability) in terms of improved performance or avoided risks.

Developed an Asset Management Plan for an Eastern Utility, addressing gaps that preclude its designation as competent across all elements that define an effective Asset Management system. Applying the ISO 55000 criteria, the resulting plan laid out a plan to achieve this level within three years, with identified / budgeted initiatives and a performance dashboard, against which progress can be measured.

Conducted an enterprise-wide review of a mid-western electric and water municipality to corporate organization structure considering pre-established strategic goals and six major initiatives, all geared towards its vision as a Utility of the Future. Included was the establishment of a Project Office for a new CCGT plant, the planned retirement of a coal-fired station, four major IT / OT initiatives, considerations regarding aging workforce and the attending opportunities to retool its staff, a mandate to reduce O&M spending by 15 percent, all within the construct of managing risk during a major industry transformation. His efforts included detailed analyses of staffing levels, worker productivity, O&M program execution, and capital efficiency, benchmarking cost, and service level performance, and identifying industry best practices to close identified performance gaps, Recommendations were presented and accepted by the utility (with minor adjustments) and is in the process of extending the contract to include implementation support.

Worked with a west coast electric utility in establishing a Project and Portfolio Management function. Starting with defining criteria for evaluating and selecting projects for execution, the process framework put in place provided the governance and operating guidelines to manage a portfolio and specific projects throughout the fiscal year, establishing the concepts of "contingent" projects, the capture of value, risk mitigation and transparency in comparing the value of electric production and energy delivery investments.

Supported a mid-western electric utility's rate case, testifying to the veracity of its asset, risk, and performance management programs and efforts underway to address significant challenges with its central business district underground network system. Consistent with Mr. Cummings' recommendations, he participated in a collaborative effort to define an oversight process that focuses on a comprehensive performance dashboard of KPIs and monitoring progress towards an Industry Leading Asset Management process.

Spearheaded efforts to provide third party assessments of a mid-Atlantic electric utility's capital investment, O&M spending levels and service level performance in support of a base rate filing; and later assessed the prudence of decisions made in the events leading up and during three extraordinary storm events during the 2011 - 2012 timeframe. He led a comprehensive benchmarking effort, focused on productivity (unit cost), reliability, and storm restoration performance. In both instances, he provided written direct and oral testimony during cross-examination demonstrating the utility's effectiveness in balancing operational performance, cost, and risk mitigation.

Assisted a mid-western utility in developing a System Revitalization Program for submittal to its Board of Directors and State Regulator. The proposed plan provided profiles of projected capital and O&M cash flows, the capture of utility and customer benefits and risks, and an industry context around which to justify such a program. The results of this effort were entered testimony in support of the utility's filing for a capital rider, for which it received sufficient funds to support the initial 18 months of a 10-year program.

Assisted a Canadian utility in offering an independent third-party assessment of a recent PBR filing performing high-level comparative analyses (benchmarks) of proposed growth and capital investments geared towards infrastructure renewal over a 5-year period; and assessing the risk of returning to previously established lower capital investment plans. This effort included providing testimony as part of a formal hearing with the Provincial Utility Commission.

Served as Project Director for a full-scale business renewal effort, establishing a plan to improve the efficiency of capital investments, and decrease O&M spending by $50 million annually without any noted decrease in system performance or increase in operational risk. Conducted across the entire enterprise with a focus on worker productivity (O&M program unit costs), capital efficiency (capital investment portfolio and unit cost management), this effort launched a series of initiatives that over 10 years will decrease spending levels by a cumulative $500 million and set the stage for transitioning to the Utility of the Future. Areas of focus included comparative cost and service level analyses, work planning and execution, performance dashboards, transmission and distribution reliability, capital portfolio optimization, and business value/risk tolerance frameworks;

and addressed the necessary infrastructure to construct a “first-of-its-kind” carbon capture generating facility.

Performed a capital and O&M spending and risk mitigation diagnostic for a mid-level Midwest utility in support of an overall business case to infuse more capital into its transmission and distribution infrastructure. The case was compelling enough to present to the Board of Directors and the Commission State and will be a cornerstone for subsequent strategic planning and future rate filings.

Supported a mid-level Midwest utility in its energy efficiency/demand response filing with the state regulatory and governing entities. Applied industry comparative analyses in demonstrating value capture / risk avoidance for all stakeholders (investors, customers, and utility) and validated that the proposed program met the intent and letter of the legislative mandate.

Conducted an enterprise-wide capital efficiency assessment for a Canadian Utility spanning electric transmission and distribution and electric generation. In reviewing their planned capital expenditures over a 10-year period, Mr. Cummings led the analyses of worker productivity (unit cost) and capital project execution and developed a plan to (1) reduce the current planned capital expenditures by 25 percent and (2) optimize the allocation of capital over the 10-year planning horizon with due consideration to optimizing the trade-offs between value and asset risk.

Strategic advisor for a major transformation effort within a U.S. Midwest electric and water municipality, that included conducting performance diagnostics (benchmarks) of its engineering and production divisions, development of a work planning and outage management program (and support processes), and several initiatives focused on achieving organizational alignment. Supporting efforts included oversight of the completion of a CCGT Plant (including supporting negotiations with GE for a LTSA), establishing criteria and process for the converging IT/OT, and the creation of an Organizational Efficiency and Effectiveness model.

Led the implementation of a process (and supporting software) to optimize the capital spending profile across three operating companies within a large US-based electric and gas company (electric transmission and distribution, gas transmission, distribution and storage, fleet, and electric generation); as well as one of the largest gas utilities in the US Midwest. In performing these projects, Mr. Cummings facilitated the linkage of a proposed investment’s value and its contribution to overall corporate strategy as well as the risk should a specific investment be deferred; and equally importantly, implemented the process in a manner that garnered organizational support for change.

Participated in a task force and subsequently joined the implementation team in developing and executing a five-year plan to revamp the electric transmission and distribution infrastructure for the Chicago business district. This effort involved the translation of highly technical specifications and detailed budgeting information into terms easily understood by commission staff, city government, and the utility’s customers. All external stakeholders (i.e., Board of Directors, City of Chicago, Commission Staff and State Regulator accepted the plan. While supporting implementation, Mr. Cummings developed the strategies and plans for initially routing, certifying,

designing, and installing 135kV and 345kV transmission to meet projected load growth and system reliability requirements. He played a key role in shortening the certification period by as much as 50 percent. This required effective liaison and communication with the Illinois Commerce Commission and Army Corps of Engineers as well as coordination of Commonwealth Edison's engineering and construction organizations and their assigned "contractors of choice."

Worked in a variety of capacities for a nuclear engineering consulting company, serving initially as a Project Manager and ultimately as the Vice President of Nuclear Engineering. Over this 11-year period, he played a major role in growing annual revenues from $5.0 million to $50.0 million while increasing market penetration to approximately 75 percent of the US nuclear utilities. He developed many of the skills and competencies used in his roles as management consultant (summarized above) through his hands-on experience in managing over 425 engineering professionals and overseeing the management of over 500 projects annually.

Worked in a variety of capacities for Stone and Webster Corporation, primarily assigned to major nuclear power plant design and construction projects. Specific assignments included:

- Assignment to the Beaver Valley Power Station project, establishing a projects control process and system within the Duquesne Light Company to manage the installation of Three Mile Island modifications in support of the second refueling outage, improving actual performance in terms of work performed and schedule duration from the initial refueling outage by a factor of three. Following this effort, Mr. Cummings shifted his focus to the unit under construction (unit no. 2) where he installed a process to facilitate the final turnover of the systems (and accompanying documentation) to plant operations over an 18-months period.

- Assignment to Clinton Power Station, where he acted as Project Controls Manager for the contractor, facilitating the lifting of 12 Nuclear Regulatory Commission (NRC) imposed stop work orders and subsequent construction and turnover of the plant to the Illinois Power Company (IPC). Key activities over a two-year period included a successful Fuel Load Caseload presentation to the NRC, rate case preparation, an information system installation to track the turnover of all systems and instituting an integrated cost and schedule process and system to support weekly and monthly reporting to project and IPC executive management. His role in integrating the construction and system turnover schedules (and subsequent development of computerized detailed system turnover punch lists) served as a primary catalyst for successful completion of the Clinton Power Station project.

Served in the U.S. Navy in increasingly responsible roles culminating as a Weapons Officer on a destroyer, USS Robert E. Peary (FF-1073). In this capacity, he managed and led three divisions totaling 100 sailors, responsible for the maintenance and operation of all weapon and detection systems, the major equipment necessary to support basic seamanship evolutions, and daily consumables for the entire ship's force. He left the U.S. Navy in 1980, having earned the Navy Achievement Medal for his efforts during two extended deployments and extraordinary performance in the areas of Anti-Submarine Warfare and Naval Gunfire Support.

COMMON CORPORATE OM&A – PLANNING

1.0 INTRODUCTION

Planning is responsible for identifying and managing transmission and distribution system planning needs, coordinating customer and stakeholder planning, developing investment strategies and governance, and advancing continuous improvement and industry alignment to support safe, reliable, and compliant system operations. Planning also leads the integrated system planning processes that support Hydro One's annual investment plans and multi-year rate application investment plans as described in SPF Section 1.7.

Planning expenditures for the historical (2023-2026), Bridge (2027) and Test (2028) years are shown in Table 1. Table 1 also shows Planning expenditures allocated to Hydro One's business segments consistent with the common corporate cost allocation model described in Exhibit E-04-08. In accordance with Hydro One's Overhead Capitalization Methodology, as described in Exhibit C-08-02, a portion of the Planning expenditures in Table 1 are capitalized, as described in Exhibit E-04-02 (Other OM&A), reducing the overall Planning expenditures that are recovered in OM&A.

Table 1 - Summary of Total Planning Expenditures ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Planning	44.3	47.4	46.6	49.9	51.0	66.9
Total	**44.3**	**47.4**	**46.6**	**49.9**	**51.0**	**66.9**
Allocated to Transmission	26.5	28.3	28.4	33.1	33.3	39.1
Allocated to Distribution	17.7	18.2	17.4	16.0	16.9	19.8
Allocated to HOSSM	0.2	0.2	0.1	0.3	0.3	0.1
Allocated to Other[1]	0.0	0.7	0.7	0.5	0.5	8.0

[1] As discussed in Exhibit E-04-08, the amounts allocated to Other in Table 1 above reflect costs allocated to Hydro One Inc., Hydro One Limited, Hydro One Networks non-regulated segment, Remotes, B2M LP, NRLP, CLLP, future partnerships, as well as other non-regulated segments.

The 2028 Test Year expenditure for Planning is $66.9M, a $22.6M increase over 2023 actuals, and a $19.1M increase over the average of the last rate period (2023-2027). The increase in 2028 Planning expenditures is driven by the need to align Hydro One's planning capacity and specialized capabilities with the larger, more complex 2028-2032 capital and OM&A work program forecast, including higher volumes of customer connection assessments, bulk and regional planning studies, asset condition and risk evaluations, and increasingly sophisticated modelling and analytics to support system growth, modernization, reliability, compliance, and customer needs and priorities. A more detailed explanation of the drivers of the 2028 Test Year forecast and historical period variance is provided in Section 3.0 below.

2.0 SUMMARY OF THE PLANNING FUNCTION

Planning uses an asset management model to identify, evaluate, and manage transmission and distribution system needs, supporting cost-effective decisions that maintain safe and reliable service for customers. Planning activities include:

<u>Asset Lifecycle Strategy and Optimization</u>

- Developing functional standards and lifecycle strategies to optimize asset life-cycle costs while maintaining system safety and reliability.
- Monitoring asset condition, performance, and risk to inform maintenance and replacement decisions, as outlined in TSP Section 2.2 and DSP Section 3.2.
- Establishing and planning asset maintenance, sustainment, and corrective action strategies, including reliability-centred and condition-based maintenance approaches.

<u>Needs Identification and Risk Management</u>

- Identifying emerging asset, system, and customer needs by monitoring asset condition, performance, and reliability risk.
- Assessing system capability and performance to ensure ongoing compliance with safety, reliability, and power quality requirements.

Technical Expertise and Specialized Studies

- Providing technical support and conducting specialized studies and investigations for system disturbances, short-circuit analyses, geomagnetic disturbance risks, stray voltage, reliability and power quality performance.

Customer and Stakeholder Planning Coordination

- Coordinating planning activities with customers, including responding to requests for new or expanded connections to enable economic growth and addressing reliability or power quality concerns.
- Obtaining and incorporating customer feedback into investment planning where applicable.
- Collaborating with neighbouring utilities, planning authorities, and regulatory bodies to align planning assumptions and needs, policy direction, and enable coordinated system development.

Investment Planning and Governance

- Scoping, developing, and evaluating candidate capital and maintenance investments to address identified system and asset needs, regulatory obligations, and customer requirements.
- Leading Regional Planning processes as discussed in SPF Section 1.2 and participating in the IESO's Bulk System Planning process as discussed in TSP Section 2.6.
- Conducting the integrated system planning processes that support Hydro One's annual investment plans and multi-year rate application investment plans as discussed in SPF Section 1.7.
- Managing investment development and release processes and coordinating with operations teams to support effective work execution.
- Supporting the reprioritization of investments to manage unforeseen events, execution constraints, or prioritized risks and integrating these changes into plans.
- Delivering analytics, reports, and special studies to enable informed decision-making and demonstrate performance, prudence, and compliance.

Continuous Improvement and Industry Alignment

- Providing subject-matter expertise and representation in national and international standards bodies, industry entities, and planning forums (including NERC, NPCC, IESO, IEC, IEEE, CSA, and others) to monitor and participate in the development of new and revised standards and guidelines, as well as share learnings and operating experience, and support industry knowledge development.
- Contributing technical and policy input and review through participation in industry and regulatory working groups and panels, including various OEB working groups and the IESO Technical Panel, on policies, processes, and changes. This includes work on distributed energy resource policy, integrated policy planning processes, and other technical matters.
- Overseeing research, development, and demonstration initiatives to address emerging operational and strategic challenges in collaboration with industry organizations and research institutions.

3.0 TEST YEAR AND HISTORICAL PERIOD VARIANCE EXPLANATION

The 2028 Test Year expenditure for Planning is $66.9M, a $22.6M increase over 2023 actuals, and a $19.1M increase over the average of the last rate period (2023-2027). The 2028 Planning expenditures are driven by the need to align Hydro One's planning capacity and specialized capabilities with the growing and more complex 2028-2032 capital and OM&A work program forecast.

Over the 2023-2027 period, higher and sustained industry inflation along with increasing work program requirements such as growth in customer connection, regional planning and bulk planning investments, have required Hydro One to continually assess and reprioritize work across its capital and OM&A programs. Despite the increase in, and complexity of the work programs supported by Planning, expenditures were managed and increased over this period below the OEB inflation rate. Consequently, Planning's overall staffing level remained stable as it absorbed this work program growth through existing resources by prioritizing work and achieving efficiencies through process standardization and enhanced data and analytics.

Over the 2028-2032 period, Hydro One is forecasting a continued increase in transmission work driven by significant growth in customer connections, substantial growth in mandatory work arising from regional planning and bulk planning, including government-directed work and responding to deteriorated transmission assets (see TSP Section 2.8 (capital) and E-02-01 (OM&A)). Similarly, Hydro One is forecasting a growing distribution capital program driven by significant load growth and increasing customer connection requests, investments to expand system capacity and enable new capabilities, enhancements to storm response and increasing automation, efforts to harden targeted assets against severe weather, and the need to address aging and deteriorating distribution assets (see as outlined in DSP Section 3.8 (capital) and E-03-01 (OM&A)).

Consequently, Planning will need to complete an increased volume of customer connection studies, planning studies, asset condition and risk evaluations, and more sophisticated modelling and analytics to support system growth, modernization, reliability, and compliance with expanding regulatory obligations. Much of the work consists of mandatory work related to customer connections which is subject to the Transmission and Distribution System Codes, as well as IESO-driven work arising from Regional Planning and Bulk System Planning, which investments are significant in scale and complexity and underpin economic growth and mandated system expansion needs. To respond to this significant and mandatory work program growth and complexity, Planning's current capacity and specialized capabilities must be expanded. At the same time, planning activities are becoming more interdependent, requiring greater coordination across Transmission, Distribution, customers, agencies, municipalities, and sectors.

In addition, Planning must introduce new programs to comply with a growing landscape of regulatory requirements including the OEB's Vulnerability Assessment and System Hardening requirements (EB-2024-0199), Non-Wires Solutions requirements (EB-2024-0118) and Reliability and Power Quality requirements (EB-2021-0307). Furthermore, Planning is introducing new programs in response to customer needs and preferences, as well as industry standards and codes, and must be ready to respond to evolving policy, regulatory, technology and system requirements. Planning functions operate at the

forefront of challenges that are not unique to Hydro One but are increasingly affecting the broader electricity sector: aging infrastructure, environmental-related risks, the pace of the energy transition, and changing customer expectations which are compounding the complexity and work volume of the planning environment.

Based on the foregoing, the 2028 Planning forecast reflects the funding required to support a growing and increasingly mandatory and complex capital work program and increasingly complex OM&A planning activities. The forecast reflects the effort required to support new programs required to respond to and comply with an expanding regulatory landscape, while strengthening technical capabilities in key areas such as power system modelling, emerging technologies, and advanced data, analytics, and planning tools. Funding of the Planning function is necessary to ensure that planning processes remain effective and scalable as transmission and distribution system requirements grow and evolve.

Absent the proposed increase, Hydro One's Planning function would face increasing challenges in meeting required planning timelines and responding to the volume of emerging system needs identified through Regional Planning, Bulk System Planning, and other planning processes. This may reduce Hydro One's ability to develop and advance investments needed to accommodate growth, support electrification, maintain reliability, and facilitate timely customer connections. It would also limit Hydro One’s ability to proactively assess and mitigate system risks, respond to evolving regulatory requirements, and enhance planning capabilities necessary to support prudent and efficient investment decision-making.

COMMON CORPORATE OM&A – DIGITAL & TECHNOLOGY SOLUTIONS

1.0 INTRODUCTION

Digital & Technology Solutions (DTS) provides the technology, communications, security, data, and operational services that enable Hydro One to safely operate and manage its transmission and distribution systems while delivering services and support to customers. DTS manages computer systems (hardware, software, and applications), data and voice communication networks, and cyber and physical security systems. Information Technology (IT) systems support Hydro One's enterprise and customer-facing business processes, while Operating Technology (OT) systems support real-time monitoring, control, and operation of Hydro One's transmission and distribution electricity networks. Security systems protect physical and cyber assets from evolving threats. This exhibit focuses on the operating, maintenance and administration (OM&A) expenditures associated primarily with IT. OT expenditures are further discussed in Exhibit E-04-05.

The role of technology within Hydro One continues to rapidly evolve. Technology is no longer primarily a tool used to improve administrative efficiency or customer convenience. Digital systems have become embedded within day-to-day operation and now support the delivery of essential transmission, distribution, and customer functions. Technology platforms are crucial for core business activities such as customer interactions, outage management, asset management, engineering, work execution, system monitoring, regulatory reporting, financial management, cybersecurity, telecommunications, and corporate operations. The availability of these systems in a secure environment has therefore become increasingly important to Hydro One's ability to deliver safe and reliable electricity service.

Technology reliance continues to increase as systems and data become more complex. Hydro One manages millions of customer, asset, operational, and engineering data records for its geographically dispersed territory. The scale, complexity, and real-time nature of utility operations increasingly require automated and integrated digital systems to support operational decision-making, work execution, customer interactions, and

regulatory compliance. Availability and access to systems and data enable employees to access accurate information, coordinate work across the organization, monitor assets, respond to outages, manage customer requests, and support operations of critical transmission and distribution infrastructure. Growth occurs over many areas including the number of customers on distribution and transmission, the number of connected grid devices sending real time performance and electrical network information, work management devices used by field crews, and the number of new technology systems and platforms being introduced for operating business processes. This growth has resulted in significantly larger data volumes to be managed. The need for accurate, timely, and securely governed data has therefore continued to increase to support the effective and safe operation of the business. The increase in number of technology systems and increasingly integrated nature of the digital landscape requires corresponding increases in investment to monitor, support, license, and properly maintain these systems.

For many years, funding constraints have required the organization to defer portions of its technology lifecycle, resiliency, recoverability, and security investments. As a result, a growing portion of the technology environment now consists of aging and unsupported infrastructure, end of life hardware and software, declining vendor support, and accumulated technical debt. These constraints have also affected newer and still-supported platforms where routine maintenance, patching, and optimization activities have been deferred, creating additional operational risk even where vendor support remains available. This has created significant vulnerabilities across the environment, particularly where end of life, end of support, legacy, or under-maintained technologies continue to support business and operational functions. Increases in technical debt increase risk and frequency of system incidents, requiring sustainment effort to focus on reactive maintenance in response to correct problems, instead of utilizing available sustainment efforts to perform proactive activities. With each incident, time and effort are spent troubleshooting across the landscape and recovering services. Sustainment activities such as patching require increased levels of validation and testing, and may require manual vendor workarounds, or additional specialist support requirements to remediate Hydro One related technical interdependencies.

At the same time, the cyber threat landscape has changed dramatically. Threat actors are more sophisticated, better funded, more persistent, and increasingly focused on critical infrastructure organizations. The frequency, scale, and impact of ransomware, supply chain attacks, nation-state activity, credential compromise, and targeted cyber campaigns continue to increase.

The funding levels in the 2023-2027 period have resulted in a continued increase in Hydro One's technology operational risk. The current risk profile is driven by end-of-life and unsupported technology, reduced vendor support, accumulated technical debt, expanding cyber and physical security exposure, growing data volumes, and greater reliance on integrated systems, cloud platforms, and recoverability capabilities. These conditions directly affect Hydro One's ability to maintain reliable operations, respond to incidents, recover from disruptions, and sustain essential utility services. As the technology environment continues to age and the threat landscape continues to evolve, the likelihood and impact of significant failures, prolonged outages, cybersecurity incidents, physical security events, and recovery challenges continue to increase.

Over the 2028-2032 period, many legacy systems, and associated technical debt, are proposed to be addressed through the capital and pre-paid investments (summarized in GSP Section 4.8.4.3). While risks associated with technical debt will be reduced, these investments do not eliminate sustainment requirements. Once systems enter service they create ongoing obligations for licensing, vendor support, cybersecurity management, monitoring, upgrades and operational support. As Hydro One expands its technology capabilities, corresponding sustainment requirements increase.

The system investments in technology (summarized in GSP Section 4.8.4.3) also represent a larger portion of spend in prepaid expenditures, as technology providers continue to shift their supported solutions to be cloud-native. Vendors of cloud-native solutions often require customers to remain in a supported version and force the adoption of patches and hotfixes. The increased requirement to adopt or implement patches and fixes, combined with their increasing frequency across the industry, means that Hydro One

must rigorously maintain its environments and increasingly have systems and processes in place to support pre-and post-validation and testing. These activities must extend beyond the source system, needing validation of connected upstream and downstream applications. In certain cases, introducing a patch or system required fix may require extended effort to resolve configuration conflicts or data conflicts between systems that arise as a result.

Growth of the technology landscape and increases in data volumes within and across systems, as well as the shift of new systems to cloud have all also increased required expenditure on licences for maintenance and vendor support. Cloud systems often result in higher annual licensing costs compared with on-premise systems, as upfront costs of infrastructure and the purchase of perpetual licences are avoided. This results in an increase in annual OM&A costs to maintain systems. Licensing also now varies between vendors, with differences in how services and fees are distributed. Many vendors require licensing that scales with company growth, often based on data volumes, the number of processes executed, or other pay-per-use metrics. The increase of overall technology footprint across Hydro One, combined with the growing transmission and distribution work programs, means increasing costs associated with licensing.

The proposed OM&A funding supports the risk remediation and sustainment activities required to maintain a secure, supportable, recoverable, and resilient operating environment. Without adequate funding for these activities, risks will continue to accumulate, recovery challenges will become more severe, operational resilience will deteriorate, and the organization's ability to maintain, protect, and restore essential utility services will be adversely affected.

This section provides an overview of the overall OM&A spending. Section 2.0 provides further details on each of the underlying programs that comprise DTS OM&A. For a discussion of DTS' capital and cloud implementation investments, please refer to GSP Section 4.8.4.3.

1.1 OVERVIEW OF DTS EXPENDITURES BY PROGRAM

DTS OM&A expenditures are organized into the following five program areas:

- **Sustainment** – Sustainment expenditures support existing and new Hydro One IT applications and infrastructure to ensure business continuity, including maintenance, third-party software and hardware licence fees, and cloud subscription fees.
- **Business Telecom** – Business telecom expenditures include the cost of data and voice telecommunications services and those costs associated with the operation and maintenance of Hydro One's telecom network, which is comprised of a mixture of company-owned and leased facilities and equipment.
- **IT Development** – Development expenditures include application upgrades, enhancements, and the OM&A portions of both capital and cloud solution implementation projects.
- **Security** – These expenditures are required to remediate and improve security capabilities by driving continuous improvement in security awareness, security threat intelligence and analysis, data protection, physical security monitoring, industry partnerships and collaboration on security risk management, workforce screening, and the ongoing maintenance and support of security software technologies.
- **Technology Management and Project Controls** – These expenditures fund the development and implementation of technology strategies, policies and processes, architectural standards for application interoperability, infrastructure capacity, network security, regulatory compliance, and governance.

Table 1 below sets out Hydro One's planned expenditures for the 2028 Test Year, along with the forecast and actual spending level for the Bridge and Historical Years, for each of the five DTS OM&A categories.

Table 1 - Summary of Total Digital & Technology Solutions OM&A ($M)[1]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	96.6	104.9	110.6	113.3	118.9	200.3
Business Telecom	17.1	17.1	18.0	17.8	18.1	18.5
IT Development	21.4	11.1	10.0	12.0	13.4	40.8
Security	33.5	22.1	19.0	20.1	21.3	43.6
Technology Management and Project Controls	12.1	9.6	11.0	11.6	12.6	19.2
Total	**180.7**	**164.9**	**168.7**	**174.7**	**184.2**	**322.4**
Allocated to Transmission	69.1	63.1	63.8	66.6	72.2	118.4
Allocated to Distribution	109.3	98.5	99.9	105.6	109.7	201.8
Allocated to HOSSM	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*
Allocated to Other[2]	2.3	3.3	5.0	2.5	2.3	2.2

**Values are less than $50k.*

The 2028 Test Year expenditure for Digital and Technology Solutions OM&A is $322.4M, a $141.7M increase over 2023 actuals, a $147.7M increase over the average of the last rate period (2023-2027), and $138.2M over the 2027 Bridge Year forecast.

When comparing the 2027 Bridge Year forecast and the 2028 Test Year, Sustainment accounts for the largest increase, at $81.4M. The year-over-year increase includes $26.5M of cloud-related costs recorded in the Incremental Cloud Computing Implementation Costs (Account 1511) Deferral and Variance Account (DVA) and therefore not presented in the 2027 Sustainment forecast in Table 1. More specifically, the $26.5M reflects cloud-related Software-as-a-service (SaaS) licence costs, including approximately $22.4M related to the SAP S/4HANA cloud solution and associated non-SAP products required as part of the solution.

Cloud-related costs are included in the 2028 Test Year forecast because the account will no longer be applicable. Accordingly, a portion of the increase shown between 2027 and

[1] Figures presented in the table may not sum to the total shown due to rounding.
[2] As discussed in Exhibit E-04-08, Section 1.0, the amounts allocated to “Other” in Table 1 above reflect costs allocated to Hydro One Networks’ affiliates.

2028 reflects the different presentation of these costs rather than new expenditures arising solely in 2028. Accounting for the $26.5M cloud-related cost recorded in Account 1511 in 2027, Sustainment expenditures in 2028 are $54.9M higher than the 2027 forecast.

The largest driver of the required 2028 OM&A expenditure is higher third-party subscription and licence fees resulting from Hydro One's continued expansion of technology solutions across the organization, material inflationary increases, and the inclusion of the cloud-related costs, which were recorded in the Incremental Cloud Computing Implementation Costs DVA prior to 2028. Additionally, the increase in third-party contracts corresponds with the increased adoption of cloud-based technology solutions, which have higher annual subscription fees than similar solutions historically implemented on-premise. Details on inflationary pressures can be found in SPF Section 1.8, highlighting Information and Operational Technology increases of between 9% - 90% since 2020. Additional details about contract increases can also be found below in Section 2.1.2 Third-Party Contracts. Hydro One expects these cost escalation trends to continue beyond 2028, creating a gap between the OM&A amounts approved in rates and the forecasted OM&A costs for 2029-2032. Hydro One is proposing a variance account for transmission and distribution to address this gap (see Section 1.1.1 below and Exhibit G-01-03, Section 5.3 and Section 9.3 for details on the variance account).

A summary of the programs that contribute to the majority of the 2028 OM&A increase compared with the 2027 Bridge Forecast are:

- **Sustainment:** Represents approximately $81.4M, or 59% of the $138.2M increase between 2028 and 2027. This increase is largely driven by expenditures from third-party contracts. As discussed above, the increase in third-party contracts should also consider the approximate $26.5M of cloud-related SaaS licence costs forecast to be recorded in the Incremental Cloud Computing Implementation Costs (Account 1511) DVA in 2027, and therefore not reflected in the Sustainment amounts presented in Table 1. After considering the difference in cost recovery treatment, the underlying year-over-year increase in Sustainment is approximately $54.9M, or $26.5M lower than the year-over-year variance reflected in the amount

presented in Table 1. Notwithstanding this cost recovery treatment, cost increases occur on existing contracts based on vendor price increases, either annually on negotiated agreements, or larger step changes imposed during contract renewals. Additional licensing spend is required in 2028 to support the licence needs of new technology solutions implemented, such as incremental subscription and licensing required to operate, maintain, and manage the new data platform solution and embedded data products, AI, and automations developed within it (see GSP Section 4.11 G-GP-26 for details). Additional licensing is required in 2028 because of new technology projects planned to be commenced in 2028, corresponding with solutions and initiatives described in the DTS Investment Summary Documents (ISDs) summarized in GSP Section 4.8.4.3. The remaining increases relate to base sustainment activities required to maintain, monitor, and support Hydro One's technology environment and the critical business services that depend on it.

- **IT Development**: Represents approximately $27.4M, or 20% of the $138.2M increase between 2028 and 2027. This category includes OM&A costs related to IT projects that cannot be capitalized and are not included within prepaid cloud expenditures. Costs in this category include efforts for change management (e.g., facilitating training and adoption), data cleansing and migration preparation, and strategy-related work (e.g., vendor selection, early discovery work, etc.). A notable increase in OM&A in this category relates to the required funding for the S/4HANA activities required for data migration, training, and change management for the go live of the S/4HANA OneCore project (see GSP Section 4.11G-GP-29 for details). Additional increases are driven from the corresponding increase in planned capital and cloud solution work across the technology portfolio.
- **Security:** Represents approximately $22.3M, or 16% of the $138.2M increase between 2028 and 2027. Approximately $13M of this increase reflects costs that were previously recognized under NERC Security and are included under General Security in 2028 (see Section 2.4, Table 16). This spending supports real-time threat monitoring, proactive testing, and the operation of core security tools that support Hydro One's Operating Technology solutions. Security monitoring and response activities have evolved to extend across the broader OT landscape.

Common toolsets, practices, and security operations support core operating systems spanning Transmission (e.g., Energy Management System) and Distribution (e.g., Advanced Distribution Management System). As such, moving the costs of these security activities to General Security better reflects their allocation between Transmission and Distribution. Additional cost increases in this category are associated with increased funding requirements for security tool funding, labour, and external vendors to perform required activities.

Collectively, the proposed DTS OM&A expenditures provide Hydro One with reliable access to technology to complete day-to-day work operations. With Hydro One adopting a balanced technology investment, these expenditures reflect the funding needed to ensure key systems and generated data are available to support increased digital capabilities, mitigate risks—including IT and OT reliability risks, and security risks—while investing prudently to avoid future costs.

The proposed 2028 test year funding level for DTS includes $118.4M allocated to Transmission and $201.8M allocated to Distribution, as shown in Table 1 above. Transmission and Distribution funding is discussed in Sections 1.2 and 1.3 respectively.

1.1.1 DTS OPERATIONS VARIANCE ACCOUNT

Hydro One is proposing a transmission and a distribution variance account to record incremental Third-Party Contract OM&A costs that exceed the funding available through the Custom IR framework during the 2028 – 2032 rate period. These costs include hardware maintenance and software licensing, maintenance, and subscription fees required to operate, maintain, and secure Hydro One's expanding technology environment.

The proposed accounts address the risk that costs arising from vendor pricing, cloud-based consumption models, industry consolidation, and other factors outside Hydro One's control may grow faster than the funding available through the mechanistic framework. Aging technology, increasing cyber threats, and escalating physical security risks are collectively increasing Hydro One's operational risk and continued deferral of critical expenditures is no longer sustainable. Without the proposed variance account, Hydro One would be required to fund Third-Party Contracts through reductions in operational activities, increasing the risk of a material impact to grid reliability and customer service.

The accounts would not provide automatic recovery or insulate Hydro One from normal business risk; any recorded amounts would remain subject to a future OEB review for prudence and disposition. Further details regarding the accounts, including their proposed operation and eligibility criteria, are provided in Exhibit G-01-03, Sections 5.3 and 9.3.

1.2 ALLOCATION TO TRANSMISSION

In the 2028 Test Year, $118.4M or 37% of DTS expenditures is allocated to Transmission. The allocation of program level costs to Transmission is shown in Table 2.

Table 2 - Digital & Technology Solutions Costs Allocated to Transmission ($M)[3]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	34.4	37.4	39.4	42.0	43.7	72.1
Business Telecom	9.2	9.2	9.7	10.1	10.0	10.3
IT Development	6.4	3.9	3.1	2.4	6.1	13.0
Security	13.7	9.0	7.9	8.2	8.3	16.0
Technology Management and Project Controls	5.3	3.6	3.6	3.8	4.2	7.1
Total Digital & Technology Solutions Costs Allocated to Transmission	**69.1**	**63.1**	**63.8**	**66.6**	**72.2**	**118.4**

[3] Figures presented in the table may not sum to the total shown due to rounding.

The 2028 Test Year expenditure for DTS allocated to Transmission is $118.4M, a $49.4M increase over 2023 actuals, and a $51.5M increase over the average of the last rate period (2023-2027). These increases are driven by the same factors impacting the overall amounts in Table 1: between 2023 and 2028, Sustainment and IT Development grew by 110% and 103%, respectively, acting as the primary drivers of the 71% growth in Digital & Technology Solutions costs allocated to Transmission over the same period.

1.3 ALLOCATION TO DISTRIBUTION

In the 2028 Test Year, $201.8M or 63% of DTS expenditures is allocated to Distribution. The allocation of program level costs to Distribution is shown in Table 3.

Table 3 - Digital & Technology Solutions Costs Allocated to Distribution ($M)[4]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Sustainment	61.4	66.7	70.3	71.3	75.2	128.2
Business Telecom	7.4	7.4	7.8	7.7	8.1	8.2
IT Development	15.0	7.2	6.9	9.5	7.3	27.8
Security	19.9	13.2	11.1	11.9	13.0	27.6
Technology Management and Project Controls	5.7	4.0	3.8	5.2	6.1	9.9
Total Digital & Technology Solutions Costs Allocated to Distribution	**109.3**	**98.5**	**99.9**	**105.6**	**109.7**	**201.8**

The 2028 Test Year expenditure for Digital and Technology Solutions allocated to Distribution is $201.8M, a $92.4M increase over 2023 actuals, and a $97.2M increase over the average of the last rate period (2023-2027). These increases are driven by the same factors impacting the overall amounts in Table 1: between 2023 and 2028, Sustainment and IT Development grew by 109% and 86%, respectively, acting as the primary drivers of the 85% growth in Digital & Technology Solutions costs allocated to Distribution over the same period.

[4] Figures presented in the table may not sum to the total shown due to rounding.

2.0 PROGRAM DESCRIPTIONS & EXPENDITURES

2.1 SUSTAINMENT

The Sustainment program supports Hydro One's IT applications and infrastructure. It has two subprograms:

- **Base IT Sustainment** – IT sustainment support, including for applications, infrastructure, and help desk services, provided by in-house staff as well as through Hydro One's IT services contract with Capgemini;[5] and
- **Third-Party Contracts** – Hardware maintenance, and software licence, maintenance, and subscription fees paid to third-party vendors of IT applications and infrastructure.

DTS systems now form part of the foundational infrastructure required to operate Hydro One, with virtually every operational and customer-facing process dependent on their continued availability. Sustainment is required throughout the life of each system, whether legacy or newly implemented, and every new investment creates ongoing obligations for licensing, vendor support, monitoring, maintenance, upgrades, and operational support. These costs increase as Hydro One's technology landscape expands and becomes more complex through greater system integration, larger data volumes, more connected devices, and enhanced capabilities required for ongoing operations.

Sustainment program expenditures for historical, bridge and test years are provided below in Table 4.

[5] GSP Section 4.10.4 notes Capgemini has been retained as the primary outsourcing partner for DTS, performing support for Hydro One's help desk, IT infrastructure support, as well as application support for SAP, Microsoft SharePoint, and a few smaller applications.

Table 4 - Sustainment OM&A Costs ($M)[6]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Base IT Sustainment	48.6	56.8	51.9	53.0	54.9	70.1
Third-Party Contracts	48.0	48.1	58.8	60.3	64.0	130.2
Total Sustainment	**96.6**	**104.9**	**110.6**	**113.3**	**118.9**	**200.3**
Allocated to Transmission	34.4	37.4	39.4	42.0	43.7	72.1
Allocated to Distribution	61.4	66.7	70.3	71.3	75.2	128.2
Allocated to HOSSM	-	-	-	-	-	-
Other	0.8	0.8	0.9	-	-	-

The 2028 Test Year expenditure for Sustainment is $200.3M, a $103.7M increase over 2023 actuals, $91.4M over the 2023-2027 average, and $81.4M over the 2027 Bridge Year forecast. The increase between 2027 and 2028 is driven by third-party contract increases, inflationary pressures, and sustainment expenditures associated with new security, data, and artificial intelligence (AI) investments.

The spend in 2023-2027 listed above in Table 4 for Third-Party Contracts does not include amounts captured as part of the Incremental Cloud Computing Implementation Costs (Account 1511) DVA (see Exhibit G-01-01, sections 3.9 and 5.18). All third-party costs are forecasted and shown in the 2028 Test year, as the DVA account will no longer be applicable. The amounts not shown in 2027 forecasted to be included in the DVA account are approximately $26.5M, made up of multiple cloud-related SaaS licences. The largest component of this total is related to the implementation of SAP S/4HANA cloud (RISE with SAP) solution (see GSP Section 4.11, G-GP-29). The SAP S/4HANA licence, and associated cloud licences for non-SAP but required products as part of the solution are forecasted to be approximately $22.4M.

The 2028 increases to Sustainment costs compared to prior years represent the increased required funding to operate the overall technology landscape at Hydro One, at a maturity level proportionate to the growing dependence by the business and customers for reliable,

[6] Figures presented in the table may not sum to the total shown due to rounding.

resilient, and flexible technology systems. Increases in Base IT Sustainment also include the funding required to support, maintain, and operate additional systems coming live that are expanding the overall technology landscape, such as the increased use of the Data Platform (see GSP Section 4.11, G-GP-26), and ServiceNow (see GSP Section 4.11, G-GP-05). These investments in new systems and capabilities create future sustainment obligations, including ongoing licensing. Older technologies that may have been stable, have minimal ongoing licensing spend, and not needing much support had ever-increasing system risk through potential security vulnerabilities or inability to quickly recover in the event of a major incident. New implemented systems often require additional funding for ongoing sustainment to adequately monitor, configure, respond to incidents, patch, and update (including testing and validation). Software solutions are coming more heavily shifted to cloud provided solutions from vendors, which also typically means higher annual third-party licence spend.

The subprograms presented in Table 4 are discussed further in the following sections.

2.1.1 BASE IT SUSTAINMENT SERVICES

The Base IT Sustainment Services subprogram monitors existing applications and infrastructure, supports these applications and infrastructure, and completes the necessary maintenance to keep services operational. This work is performed by in-house staff as well as by Capgemini, Hydro One's primary IT outsourcing vendor.

Base IT Sustainment services include four categories:

1. **Application Maintenance** – This category includes the maintenance and support of approximately 600 business software applications. Capgemini mainly manages support for the large enterprise SAP, Microsoft SharePoint and Microsoft Customer Relationship Management (CRM) solutions, while Hydro One manages most other applications in-house. Application lifecycle maintenance activities for these applications would include vendor patching, vulnerability remediation, configuration management, integration support, performance monitoring, user support, and incident management. Sustainment in this category would continue

to be required for applications, even if they are undergoing separate investment to be replaced or upgraded, until they are fully retired.

2. **Data Centre Services** – This category includes the operation, maintenance, and management of IT hardware (servers, mainframe, storage area network, network routers, and switches), operating systems, and other infrastructure located at the data centre (production and backup) facilities. Capgemini provides support for IT service management, business continuity plan & disaster recovery support, infrastructure monitoring, end-to-end incident management, and batch job processing.
3. **Distributed Server Sustainment** – This category includes support services to maintain and operate application and file servers. These servers are used to run business applications and admin systems such as file storage, email exchange, and security monitoring systems; and
4. **Help Desk** – This category includes the daily management and maintenance services delivered to Hydro One personnel across the province by telephone, remotely, or through field technicians, along with the implementation of Artificial Intelligence services to enable transactions such as password resets.

2.1.1.1 PROGRAM EXPENDITURES

Base IT Sustainment OM&A expenditures for historical, bridge and test years are provided below in Table 5.

Table 5 - Base IT Sustainment OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Base IT Sustainment	48.6	56.8	51.9	53.0	54.9	70.1

The 2028 Test Year expenditure for Base IT Sustainment OM&A is $70.1M, a $21.6M increase over 2023 actuals, a $17.1M increase over the average of the last rate period (2023-2027), and a $15.3M increase from the 2027 Bridge year forecast.

Base IT Sustainment costs were largely consistent from 2023 to 2027. The increase in actual spend in 2024 was primarily due to additional scope added to the Capgemini sustainment contract to support the newly deployed Distribution Design Optimization and Transformation (DOT) and ServiceNow solutions. In 2025, Hydro One renegotiated a new Capgemini services contract which resulted in realized savings to Hydro One for similar services ongoing to 2028. This realized savings from the services agreement is the primary driver for the decrease in costs in Base IT Sustainment costs, representing approximately $3.6M decrease in annual spend.

The $15.3M increase between the 2027 Bridge Year and the 2028 Test Year is largely driven by:

- Necessary increases in sustainment activities required to perform adequate lifecycle management of the application and infrastructure landscape. Approximately 35% of the approximate 600 business applications are beyond a vendor end of support date. Deferred funding in previous years means some of these applications are not actively managed, with sustainment support provided as reactive, if an incident arises. This approach has continued to increase the overall operational risk to the business. While some applications may continue to function, even when out of support, often it is the patching and maintenance of the underlying infrastructure (servers, database, and networking) which causes changes in configuration and protocols that can impact performance or the ability to run the application. Funding increases of approximately $7.1M account for the corresponding increase in sustainment that would improve the monitoring and operational oversight to better understand the full stack (application and associated infrastructure), and be able to test and validate changes, taking mitigating actions prior to an incident or service outage. This funding also provides necessary inflationary cost increases to cover personnel performing sustainment activities, as well as increase in sustainment for new applications as part of the technology footprint growth and ongoing investments.
- Approximately $3.2M increase is associated to security sustainment to address temporary physical security monitoring requirements (e.g., security guards or

temporary camera installations) for scenarios such as system outages or construction sites, required to deter theft of equipment and materials. This also supports personnel related increases, such as for timely investigations of Code of Business Conduct violations.

- Approximately $2.8M allocated to the ongoing sustainment of the data systems and associated support. This includes required monitoring, system configurations, patching, governance controls, security controls, user community oversight, and system incident response for the data systems being implemented in 2026 and 2027. Systems include the data platform (Snowflake), data catalog, data governance, and AI platform tools (See GSP Section 4.11 G-GP-26 for more details). This increase in sustainment spend is based on timing, as new data sources become integrated further in 2028, such as a major uplift with the integration of data from SAP, as part of the S/4HANA implementation (see GSP Section 4.11 G-GP-29). As the data platform becomes populated with additional enterprise data, additional sustainment and support is required to administer the tool with the growth in users and employees. Additionally, the increase in use cases developed (through investments in GSP Section 4.11 G-GP-26) will also require corresponding increases in sustainment oversight to ensure the stability, data integrity, and user access of the data is adequately managed.
- Approximately $1.7M is required for matured sustainment of disaster recovery capabilities, as well as increases in cloud infrastructure management. Increases are required in sustainment of Disaster Recovery (DR) capabilities, ensuring Hydro One's critical IT systems can be restored quickly and reliably in the event of outages, cyber incidents, or large-scale disruptions. DR capabilities today do not have dedicated support and become outdated. Without dedicated support, recovery processes may become outdated, untested, or misaligned with evolving infrastructure, leaving Hydro One vulnerable to prolonged outages and compliance issues. Funding in this category will also provide necessary improvements in how cloud infrastructure, managed through Hydro One’s hyperscalers, are managed, including the oversight of environments, securing access to various infrastructure components (i.e. containers), managing scalable storage and compute

requirements, and includes backup/restore, disaster recovery, and archiving systems.

2.1.2 THIRD-PARTY CONTRACTS

The Third-Party Contract subprogram is comprised of fees related to hardware maintenance, and software licence, maintenance, and subscription fees paid to third-party vendors of technology applications and infrastructure.

2.1.2.1 PROGRAM EXPENDITURES

Third-Party Contract expenditures for historical, bridge and test years are provided below in Table 6.

Table 6 - Third-Party Contracts OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Third-Party Contracts	48.0	48.1	58.8	60.3	64.0	130.2

The 2028 Test Year expenditure for Third-Party Contracts is $130.2M, an $82.1M increase over 2023 actuals, a $74.3M increase over the average of the last rate period (2023-2027), and a $66.1M increase from the 2027 Bridge year forecast.

As noted above in Section 1.1, third-party contract costs for 2023-2027 as shown in Table 6 do not include the amounts that are separately captured (or forecasted to be captured) in the Incremental Cloud Computing Implementation Costs (Account 1511) DVA (see Exhibit G-01-01, sections 3.9 and 5.18). This accounts for $26.5M of additional third-party contract spend forecasted for 2027. This DVA forecast amount accounts for approximately $4.1M of cloud SaaS spend ongoing from prior year pre-paid solution implementations, and approximately $22.4M of SAP S/4HANA RISE with SAP and other associated non-SAP vendor annual cloud subscription fees.

Including the $26.5M forecast to be recorded in the DVA, anticipated 2027 Third-Party Contract expenditures are approximately $90.5M. These costs are included in the 2028 OM&A forecast because the DVA will no longer be applicable. The increase from this adjusted 2027 amount of $90.5M to the 2028 Test Year forecast of $130.2M is attributable to the following factors:

- **AMI 2.0** licensing increases of approximately $3.3M from the increased deployment of the AMI 2.0 solution, covering the device and headend system annual subscription and licensing fees, partially offset by decreasing lower cost AMI 1.0 licensing costs.
- **Data, AI, and Analytics** platform growth and solution deployment licensing increases of approximately $10.3M. Due to timing of key data volume ingestion into the data platform (Snowflake) in 2028 such as SAP, GIS, and additional AMI 2.0 volumes, as well as the creation of additional data products, analytic and AI solutions for the company, licence costs are required based on the commercial models, typically based on size and consumption (users and data use).
- **Infrastructure** licensing increases of $6.5M as a result of infrastructure refreshes as well as cloud hyperscaler licence requirements.
- **Work and Asset Management** solutions account for approximately $4.3M in required increases. This funding supports the licence and cloud subscription costs associated with the growth in required solution investments per GSP Section 4.11, G-GP-08. When new projects commence, cloud licensing that is incurred from initial contract signing, is funded through this category. In addition, the increased use of cloud solutions results in higher annual OM&A from SaaS contracts compared with funding requirements in prior rate filings that may see the majority of licences purchased as one-time capital expenditure with much lower annual licence maintenance fees.
- **Customer and Enterprise platforms** account for approximately $10.8M in required increases. Similar to Work and Asset Management, this category includes licensing for new solutions associated with investments in GSP Section 4.11, G-GP-05 and G-GP-07. Of this $10.8M, approximately $9.0M is planned for the

ServiceNow platform, to be used across the company for multiple capabilities (see GSP Section 4.11, G-GP-05).

- **Inflation and vendor pricing increases** account for approximately $4.5M, as a result of a planned net 5% impact on the overall 2027 levels.

Hydro One has experienced vendor price increases above CPI, driven by high demand across the technology sector, increased hardware and memory costs, and industry consolidation, licence model changes, among other factors. Each year, Hydro One experiences growing pressure of price increases from vendors more willing to change their long-established pricing models, or demand large annual price increases to maintain the same level of service or usage. In 2026, Hydro One executed 16 licence renewals each with an average increase of 23% compared to the previous year. In one instance, a vendor changed its licensing model from concurrent enterprise licences to user seat-based licensing, which, combined with price increases, resulted in a renewal price representing a 200% annual increase over current spend. In other cases, external forces such as market consolidation can result in unexpected changes to licences. Notably, Hydro One was impacted by significant cost increases for the licensing of VMware products following Broadcom's acquisition of VMware in late 2023. Industry sources have reported that some customers experienced pricing increases ranging from 800% - 1500%.[7]

To manage these impacts, Hydro One began implementing formal internal processes in 2024 for optimizing third-party contracts:

- 12 months before contract renewal (or longer for higher risk contracts), Hydro One evaluates contracts for potential savings, including evaluating the current usage for possible reduction, suitability of lower cost alternative technologies and vendors, and possibility of consolidating contracts with a single vendor for pricing leverage. Larger contracts may require external expertise to support negotiations or system analysis to determine the minimum requirement. Hydro One

[7] Udhayakumar G K, Software Pricing Guide, *VMware Pricing After Broadcom: The 800–1,500% Price Shock, What Changed, and Your Real Alternatives in 2025* (April 4, 2026)

continuously measures licence usage against entitlement to eliminate overbuying and optimize current licensing.

- Hydro One maintains relationships with key vendors through regular meetings and efforts to develop strategic partnerships, with a goal of maximizing benefits through consolidating contracts and bulk discounts. Early indications of licence model changes can result in Hydro One evaluating the technology landscape to determine if a change in solution is warranted.

Through these processes, Hydro One has achieved several contract cost reductions for various licence renewals. Over the 2025-2026 period, examples of Hydro One's strong and prudent licensing renewal and negotiation approach led to over $10M in total contract (multi-year) cost avoidance.

As a result, Hydro One has forecasted an overall pricing increase to the portfolio of 5% net inflation. This is expected to cover typical increases and growth in licence costs due to company growth (e.g., some licences would increase due to increases in headcount, data volume, customers, etc.). Hydro One forecasts the annual growth reflected in 2028 Third-Party Contract OM&A costs will continue throughout the 2028-2032 period.

As described in Section 1.1.1, Hydro One is therefore proposing transmission and distribution variance accounts to record incremental Third-Party Contract OM&A costs that exceed the funding available under the Custom IR framework during the 2028-2032 rate period. Any amounts recorded would remain subject to future OEB review for prudence and disposition. Further details regarding the accounts, including their proposed operation and eligibility criteria, are provided in Exhibit G-01-03, sections 5.3 and 9.3.

2.2 BUSINESS TELECOM

The Business Telecom program includes data and voice telecommunications services and associated operation and maintenance of Hydro One's telecom network, which is comprised of a mixture of company-owned and leased facilities and equipment. The Business Telecom program has four subprograms:

- **Operations and Carrier Management** – telecommunications monitoring and network operations for Hydro One's power system and business operations;
- **Field Services** – maintenance and repair of voice and data telecom equipment and connection changes for moves, additions, changes, and deletions;
- **Voice and Data Networks Services** – telephone service to Hydro One staff at corporate and field offices and to Hydro One Call Centers; and
- **Mobility Services** - mobile phone services and customer notifications.

The costs associated with the Business Telecom program primarily relate to third-party services. Costs vary with the data and voice telecom capacity at sites throughout the province and security-related services for the telecom network. These expenditures, for historical, bridge, and test years, are summarized in Table 7.

Table 7 - Business Telecom OM&A Costs ($M)[8]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations and Carrier Management	8.7	9.0	9.4	9.6	9.7	9.8
Field Services	1.8	1.7	2.2	2.2	2.2	2.3
Voice and Data Networks Services	6.1	5.8	5.6	5.5	5.6	5.8
Mobility Services	0.5	0.6	0.8	0.5	0.5	0.5
Total Business Telecom	**17.1**	**17.1**	**18.0**	**17.8**	**18.1**	**18.5**
Allocated to Transmission	9.2	9.2	9.7	10.1	10.0	10.3
Allocated to Distribution	7.4	7.4	7.8	7.7	8.1	8.2
Allocated to HOSSM	-	-	-	-	-	-
Other	0.4	0.5	0.4	-	-	-

The 2028 Test Year expenditure for Business Telecom is $18.5M, a $1.4M increase over 2023 actuals, a $0.9M increase over the average of the last rate period (2023-2027), and $0.4M increase over 2027 Bridge Year Forecast.

[8] Figures presented in the table may not sum to the total shown due to rounding.

From 2023 to 2027, Business Telecom costs remained relatively stable, with forecast costs in 2026 and 2027 materially aligned with the 2025 actual level, reflecting Hydro One's efforts to manage costs within the 2023–2027 plan. The 2028 forecast of $18.5M represents a modest increase relative to 2026 ($17.8M) and 2027 ($18.1M), driven by the continued need to support Hydro One's province-wide telecom network, including expanded data and voice capacity associated with the increase in work activities and workforce. Overall, Business Telecom is not a significant contributor to the DTS OM&A increase, as the 2028 forecast remains close to recent historical levels ($18.0M in 2025).

The subprograms presented in Table 7 are discussed in the following sections.

2.2.1 OPERATIONS AND CARRIER MANAGEMENT

The Operations and Carrier Management subprogram encompasses services provided by Acronym Solutions Inc. (formerly Hydro One Telecom Inc.) to provide telecommunications monitoring and network operations for Hydro One's power system and business operations. These services are critical to ensure Hydro One personnel can communicate effectively throughout the province and with customers. These items include service and support for internet, phone and mobile devices used by all Hydro One employees, which are critical for daily operations, field work, and internal collaboration. Among other things, this subprogram contributes to reduced network outages and improved productivity and service quality.

2.2.1.1 PROGRAM EXPENDITURES

Operations and Carrier Management expenditures, for historical, bridge, and test years, are summarized in Table 8.

Table 8 - Operations and Carrier Management OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations and Carrier Management	8.7	9.0	9.4	9.6	9.7	9.8

The 2028 Test Year expenditure for Operations and Carrier Management is $9.8M, a $1.1M increase over 2023 actuals, $0.5M increase over the average of the 2023-2027 rate period, and $0.1M increase from the 2027 Bridge Year Forecast. It is materially aligned with historical and Bridge Year costs.

2.2.2 FIELD SERVICES

The Field Services subprogram includes the maintenance and repair of voice and data telecom equipment, as well as the handling of connection changes for moves, additions, changes, and deletions. Given Hydro One's dispersed workforce throughout the province, it is important to ensure that staff have the proper support for the voice and data devices used in the field and to monitor and implement required changes to the field devices (e.g., adding or changing phones and phone numbers). This subprogram also includes the ongoing maintenance and monitoring of the backend IT service that allows Hydro One to perform these Field Services.

2.2.2.1 PROGRAM EXPENDITURES

Field Services expenditures, for historical, bridge, and test years, are summarized in Table 9.

Table 9 - Field Services OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Field Services	1.8	1.7	2.2	2.2	2.2	2.3

The 2028 Test Year expenditure for Field Services is $2.3M, a $0.5M increase over 2023 actuals, a $0.3M increase over the average of the last rate period (2023-2027), and $0.1M increase over the 2027 Bridge Year Forecast. It is materially aligned with historical and Bridge Year costs.

2.2.3 VOICE AND DATA SERVICES

The Voice and Data Services subprogram provides local and long-distance telephone service to Hydro One staff at corporate and field offices and to ensure customers are able to contact Hydro One Call Centers. This subprogram enables Hydro One to maintain the voice and data business telecommunication infrastructure and includes monthly data charges for circuit usage and data network services that connect Hydro One sites. These functions are essential to Hydro One's ability to run its business processes at over 150 locations throughout Ontario.

2.2.3.1 PROGRAM EXPENDITURES

Voice and Data Services expenditures, for historical, bridge, and test years, are summarized in Table 10.

Table 10 - Voice and Data Networks Services OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Voice and Data Networks Services	6.1	5.8	5.6	5.5	5.6	5.8

The 2028 Test Year expenditure for Voice and Data Services is $5.8M, a $0.2M decrease below 2023 actuals, and within a $0.1M increase over the average of the last rate period (2023-2027). It is materially aligned with historical and Bridge Year costs.

2.2.4 MOBILITY SERVICES

The Mobility Services subprogram includes mobile phone services as well as customer notifications. Specifically, costs include monthly rate plans for cell phone usage (voice and data) to major carriers such as Bell and Rogers as well as hardware upgrades for users when eligible or for the replacement of lost devices.

2.2.4.1 PROGRAM EXPENDITURES

Mobility Services expenditures, for historical, bridge, and test years, are summarized in Table 11.

Table 11 - Mobility Services OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Mobility Services	0.5	0.6	0.8	0.5	0.5	0.5

The 2028 Test Year expenditure for Mobility Services is $0.5M, consistent with 2023 actuals, and a $0.1M decrease below the average of the last rate period (2023-2027).

2.3 IT DEVELOPMENT

The IT Development program includes application upgrades, enhancements, and the OM&A portions of capital and cloud implementation projects.

IT Development costs are divided into three subprograms:

1. **Enhancements** – This subprogram makes changes to SAP and Non-SAP systems to meet legal/regulatory requirements, to deliver business functionality that meets the objectives of the business, and to further Hydro One's application rationalization strategy.
2. **Upgrades** – This subprogram includes the costs associated with necessary software releases, periodic version upgrades, and application replacements that do not meet the total capital threshold of $0.1M; and
3. **Projects** – This subprogram includes business process re-engineering costs, such as training and change management costs, that are required when new or revised IT applications are introduced. These costs are not capitalized as per Hydro One's accounting practices.

At a high level, IT Development is required to maintain applications to versions within vendor support (i.e. older versions may no longer be supported by vendors, which is a barrier to receiving necessary security patches, bug fixes, or compatibility corrections with other IT software). OT development costs are covered in Exhibit E-04-05. IT Development expenditures, for historical, bridge, and test years, are summarized in Table 12.

Table 12 - IT Development OM&A Costs ($M)[9]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Enhancements	7.2	7.2	5.4	4.8	5.3	6.7
Upgrades	6.0	3.7	3.9	5.7	6.3	7.9
Projects	8.1	0.2	0.8	1.5	1.7	26.2
Total IT Development	**21.4**	**11.1**	**10.0**	**12.0**	**13.4**	**40.8**
Allocated to Transmission	6.4	3.9	3.1	2.4	6.1	13.0
Allocated to Distribution	15.0	7.2	6.9	9.5	7.3	27.8
Allocated to HOSSM	-	-	-	-	-	-
Other	-	-	-	-	-	-

The 2028 Test Year expenditure for IT Development is $40.8M, a $19.4M increase over 2023 actuals, and a $27.2M increase over the average of the last rate period (2023-2027). These increases are largely attributable to associated capital and pre-paid project-related spend that is planned for 2028, particularly with the inclusion of spend in 2028 that is not included in the reported 2026 and 2027 forecasts as they are forecasted to be captured as part of the Incremental Cloud Computing Implementation Costs (Account 1511) DVA (see Exhibit G-01-01, sections 3.9 and 5.18).

The subprograms presented in Table 12 are discussed in the following sections.

2.3.1 ENHANCEMENTS

The Enhancements subprogram makes minor modifications to various IT applications to improve business processes or meet regulatory obligations.

In alignment with DTS' architectural principle (as discussed in GSP Section 4.2.5), this program seeks to leverage existing applications to meet additional business needs where possible and minimize the additional costs of deploying/supporting different technologies.

[9] Figures presented in the table may not sum to the total shown due to rounding.

For example, this program includes dedicated audiovisual support and administration, allowing for proactive monitoring and management, user support, coordination with IT, facilities, and security teams, and management of vendor relationships.

2.3.1.1 PROGRAM EXPENDITURES

Enhancement expenditures, for historical, bridge, and test years, are summarized in Table 13.

Table 13 - Enhancements OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Enhancements	7.2	7.2	5.4	4.8	5.3	6.7

The 2028 Test Year expenditure for Enhancements is $6.7M, a $0.5M decrease below 2023 actuals, and a $0.7M increase over the average of the last rate period (2023-2027).

Enhancements spend was consistent between 2023 and 2024, then decreased in 2025, driven primarily by normal fluctuations in required spend associated with enhancement activities. Forecast spending remains lower in 2026 and 2027 due to an anticipated reduction in Customer Service Operations (CSO) service enhancements. The increase in the Enhancements program in 2028 is driven by expected volume growth in the CSO service enhancements and regulatory compliance programs, and a dedicated resource to support and administer audio-visual (AV) systems.

2.3.2 UPGRADES

The Upgrades subprogram provides lifecycle upgrades, decommissioning, security patching, cloud updates, and infrastructure modernization. These IT system upgrades are necessary to keep applications and infrastructure in a vendor-supported state, reducing security vulnerability and compliance risk while maintaining performance, reliability and

user experience. Examples include small application updates to correct a discovered defect, or to create new data fields within a program to align with current work programs.

2.3.2.1 PROGRAM EXPENDITURES

Upgrades expenditures, for historical, bridge, and test years, are summarized in Table 14.

Table 14 - Upgrades OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Upgrades	6.0	3.7	3.9	5.7	6.3	7.9

The 2028 Test Year expenditure for Upgrades is $7.9M, a $1.9M increase over 2023 actuals, and a $2.8M increase over the average of the last rate period (2023-2027).

Upgrades spend decreased in 2024 and 2025, driven primarily by timing of lifecycle and patching cycles following a data centre upgrade in 2023, then increased in 2026 and 2027 due to infrastructure refreshes. The increase to Upgrades in 2028 is driven by deferred spending on Microsoft Windows platform upgrades related to PC client security, and on patching customer-facing technology.

2.3.3 PROJECTS

The Projects subprogram captures the costs that are necessary to launch large transformational or strategic initiatives that are not captured as capital expenditures. As a result, spend for Projects fluctuates with capital project-related expenditures, capturing business process re-engineering costs, such as training and change management, as well as post in-service defect correction support.

2.3.3.1 PROJECT EXPENDITURES

Project expenditures, for historical, bridge, and test years, are summarized in Table 15.

Table 15 - Projects OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Projects	8.1	0.2	0.8	1.5	1.7	26.2

The 2028 Test Year expenditure for Projects is $26.2M, an $18.1M increase over 2023 actuals, and a $23.7M increase over the average of the last rate period (2023-2027).

Actual and forecasted Projects OM&A expenditures from 2024 to 2027 are lower than 2023 actuals because of a decrease in capital project spend over this period, and Project related costs captured separately for applicable cloud investments under the Incremental Cloud Computing Implementation Costs (Account 1511) DVA (see Exhibit G-01-01, sections 3.9 and 5.18). For consistency and to avoid double counting, 2026 and 2027 forecast totals in Table 15 continue to exclude spend assumed to be applied to this DVA account.

The 2028 increase of $24.5M above 2027 Bridge Year Forecast is driven largely by the OM&A activities required to support the expanded capital and prepaid work program described across the ISDs summarized in GSP Section 4.11. A summary of the increases is provided below:

- Approximately $11.1M for SAP related project costs. The majority is required for the completion of the S/4HANA implementation (see GSP Section 4.11, G-GP-29). This OM&A spend accounts for associated project related activities such as training, communications, data conversion, and old SAP ECC decommissioning. Additional funding is required for the associated early project preparations of the subsequent SAP Customer phase activities (see GSP Section 4.11, G-GP-29).
- Approximately $7.6M associated with project related OM&A necessary to support the planned capital and pre-paid projects to support the corporate, customer, and operations lines of business (described in GSP Section 4.11, G-GP-06, G-GP-07, and G-GP-08). Notably, $5.4M is required for the significant number of necessary

application upgrades and replacements commencing in 2028 within the Customer Service domain, as described in GSP Section 4.11, G-GP-07.

- Approximately $5.7M is required to support the preparation and project execution of major IT enterprise platform upgrades, such as for the elimination of the Oracle iHUB solution, the migration of integrations from the MuleSoft platform, and implementation of ServiceNow capabilities for IT operations, described within GSP Section 4.11, G-GP-05.

2.4 SECURITY

DTS is also accountable for planning and executing Hydro One's security programs. The Security programs protect the Company from personnel, physical, and cybersecurity risks. Hydro One's security capability is managed and overseen through enterprise-wide Security Governance to enable resilient business operations.

For this Application, the Security OM&A costs managed by DTS are presented in three separate exhibits to maintain consistency with the cost mapping presented in previous applications.

1. **General Security** – These costs are required to remediate and improve security capabilities by driving continuous improvement in security awareness, security threat intelligence and analysis, data protection, and workforce screening (as discussed in Section 2.4.1 below). This corresponds to costs reported under the title "Security" in Table 1 above, and covers common security technology operations, tools, managed services, and operational labour supporting enterprise IT and shared transmission and distribution OT environments.
2. **Security Management** – This function includes the development and maintenance of cyber and physical incident response and recovery plans for personnel, physical, and cybersecurity associated with North American Electric Reliability Corporation (NERC) assets. It also covers the establishment of enterprise-wide security standards. These costs are included within Common Corporate Functions and Services (CCF&S), as discussed in Exhibit E-04-02, Section 2.7.

3. **NERC Security** – These costs enable maintenance, monitoring and audit activities that are required to sustain the compliance of Hydro One systems and facilities with NERC Critical Infrastructure Protection (CIP) standards. These standards are designed to mitigate physical and cybersecurity risks to Ontario Bulk Energy System facilities, systems, and equipment. Standards cover physical security protection, internal network security monitoring, communications between control centres, configuration change management and vulnerability assessments, and supply chain risk management. Activities under this program include maintenance of cybersecurity assets (e.g., firewalls, intrusion detection systems), surveillance and monitoring of critical physical facilities, and conducting vulnerability and compliance assessments. The costs are included within Transmission Sustainment OM&A, as discussed in Exhibit E-02-02, Section 2.2.6.

Table 16 reflects the historical and projected spending for 2023 to 2028 across all security programs. The table is provided for contextual purposes. Of the amounts shown, only General Security is included in DTS OM&A in Table 1. Security Management and NERC Security are included in Exhibit E-04-02 and Exhibit E-02-02, respectively, and are not included in Table 1 of this exhibit.

Table 16 – Total Security OM&A Costs ($M)[10]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
General Security	33.5	22.1	19.0	20.1	21.3	43.6
Security Management[11]	8.9	7.9	7.5	9.0	9.2	9.2
NERC Security[12]	18.0	20.9	23.8	23.0	22.5	11.7
Total Security	**60.4**	**50.9**	**50.3**	**52.0**	**53.0**	**64.5**
Allocated to Transmission	35.9	33.6	35.4	35.9	35.6	32.8
Allocated to Distribution	24.3	17.2	14.7	15.9	17.2	31.5
Allocated to HOSSM	0.0*	0.0*	0.0*	0.0*	0.0*	0.1
Other	0.1	0.1	0.2	0.1	0.1	0.1

**Values are less than $50k.*

The 2028 Test Year expenditure for Security is $64.5M, a $4.1M increase over 2023 actuals, and an $11.2M increase over the average of the 2023-2027 rate period. When comparing the 2028 Test Year with the 2027 Bridge Year forecast, approximately $13M of 2028 costs have been realigned from the NERC Security category into the General Security category. As noted above in Section 1.1, this spend is for real-time threat monitoring, proactive testing, and operation of core security tools that support Hydro One's Operating Technology solutions. Security monitoring has evolved and now extends across the broader OT landscape. The 2028 allocation to General Security better reflects the investments in common toolsets, practices, and security operations support that span across both transmission (e.g., Energy Management System) and distribution (e.g., Advanced Distribution Management System). The movement of this spend to General Security better reflects the allocation between Distribution and Transmission. Further details are described below in Section 2.4.1.

[10] Figures presented in the table may not sum to the total shown due to rounding.
[11] Security Management costs are included in Common Corporate Functions and Services (CCF&S) OM&A, as discussed in Exhibit E-04-02, Section 2.7
[12] NERC Security costs are included within Transmission OM&A Sustainment, as discussed in Exhibit E-02-02, Section 2.2.6.

For clarity, only General Security costs, including the consolidated security subprograms previously associated with NERC Security, are included in the total DTS OM&A costs. The costs pertaining to Hydro One's Security Management and Transmission NERC Security functions are included in Exhibit E-04-02 (CCF&S OM&A) and Exhibit E-02-02 (Transmission Sustainment OM&A), respectively. Nevertheless, to provide the full context of Hydro One's unified security strategy, and given the significant interrelation between these functions, these functions are discussed in conjunction with General Security in the following subsections.

2.4.1 GENERAL SECURITY

Hydro One operates in an increasingly challenging cybersecurity environment as threat actors continue to target critical infrastructure and industrial control systems. Gartner research indicates that ransomware attacks against industrial organizations increased by 49% year-over-year in 2025, affecting approximately 3,300 organizations globally[13], while attacks exploiting industrial cyber-physical system protocols increased by 84%[14], demonstrating a growing focus on operational technology environments. Exploitation of vulnerabilities in public-facing applications increased by 44% and became the leading initial access vector for cyber incidents[15], while 41% of organizations reported experiencing a distributed denial-of-service (DDoS) attack in the previous 12 months[16].

The Gartner research underscores the rapid escalation in overall threats—both cyber and physical—that the energy and utility sector is experiencing, including from AI-enabled attacks, drone threats, and quantum computing. In addition, growing NERC-based regulatory requirements, especially related to physical security protection (CIP-006 and

[13] Gartner, Gartner Insights, *Cybersecurity Threat: CPS Compromise* (proprietary subscription article), in reference to Drago, Dragos OT Cybersecurity Report: Adversaries Increase Real-World Impact, Map Control Loops Across Industrial Infrastructure (May 2026).
[14] Gartner, Gartner Insights, *Cybersecurity Threat: CPS Compromise* (proprietary subscription article), in reference to Forescout Technologies, Forescout's 2025 Threat Roundup Report Finds 84% More Cyberattacks Using Operational Technology Protocols (May 2026).
[15] Gartner, Gartner Insights, *Cybersecurity Threat: Perimeter Threats* (proprietary subscription article), in reference to IBM, X-Force Threat Intelligence Index 2026 (May 2026).
[16] Gartner, Gartner Insights, *Cybersecurity Threat: Distributed Denial of Service* (proprietary subscription article), in reference to 2026 Gartner CISO Role-Based Survey (May 2026).

CIP-014) and internal network security monitoring (upcoming CIP-015-01) are increasing the need for overall common governance and controls. To meet these challenges and align with trends towards grid modernization, utility security requirements are shifting toward intelligence-driven, integrated security operations that provide real-time situational awareness across cyber, physical, and network domains. As Hydro One incorporates new sources of data to drive real-time decision making, it must also address new vulnerabilities and risks. Increased OT, cloud services, advanced analytics, distributed energy resources, and AI-enabled capabilities increase the number of systems, interfaces, vendors, and data flows that must be secured and monitored. To protect these additional data sources, security programs must transition from traditional perimeter controls towards threat intelligence, advanced detection and response, and stronger third-party risk management.

To address these needs, DTS places “security and privacy by design” at the forefront of its strategy. DTS plans to increase innovative monitoring and detection capabilities providing real-time visibility and early threat detection, enabling proactive risk management and protecting Hydro One’s critical infrastructure. Funding will support additional dedicated staff responsible for triaging escalated threats, coordinating incident response activities, managing day-to-day security operations, as well as for retaining a third-party incident response team. Security sustainment will be done through an integrated approach to operations with a unified view across physical security, cybersecurity, IT, and OT environments—enhancing situational awareness, coordination, and response.

General Security costs also include:

- Operation and sustainment of common cyber and physical security monitoring, detection, and response capabilities
- Common security software and managed services used across enterprise IT and shared transmission and distribution OT environments
- Operational labour for threat triage, incident coordination, vulnerability management, security engineering, and oversight of third-party security services;

- Security support required to integrate new technology services and enable security monitoring and response improvements; and
- Implementation and operational readiness activities for new security requirements where the capability is common across multiple business environments

Some managed services will continue to be outsourced as it represents reduced risks and costs while increasing flexibility and scalability. Among the outsourced services are physical security surveillance and cybersecurity monitoring, providing Hydro One access to specialized expertise and focused detection and response resources.

2.4.1.1 PROGRAM EXPENDITURES

General Security expenditures, for historical, bridge, and test years, are summarized in Table 17.

Table 17 - General Security OM&A Costs ($M)[17]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total General Security	**33.5**	**22.1**	**19.0**	**20.1**	**21.3**	**43.6**
Allocated to Transmission	13.7	9.0	7.9	8.2	8.3	16.0
Allocated to Distribution	19.9	13.2	11.1	11.9	13.0	27.6
Allocated to HOSSM	-	-	-	-	-	-
Other	-	-	-	-	-	-

The 2028 Test Year expenditure for General Security is $43.6M, a $10.1M increase over 2023 actuals, and a $20.4M increase over the average of the last rate period (2023-2027).

The approximately $22.3M increase between the 2027 Bridge Year and the 2028 Test Year is driven by two factors. First, two security subprograms previously recorded under

[17] Figures presented in the table may not sum to the total shown due to rounding.

NERC Security are consolidated under General Security in 2028. These subprograms account for approximately $17M of the increase in 2028, comprising approximately $13M transferred from NERC Security and approximately $4M of incremental funding for the expanded scope and cost of these activities. Second, approximately $5M relates to additional labour and third-party services within General Security.

The majority of the increase in the 2028 Test Year ($17M) is attributable to the consolidation of two security subprograms previously associated with NERC security compliance into the common security program, resulting in a greater proportion of security-related investments being reflected within the General Security program:

- **OT Infrastructure Sustainment Contract**: This subprogram funds specialized security and system management tools necessary to protect mission-critical environments, including threat detection, system integrity, and platform stability. This subprogram previously supported transmission assets. However, with the rapid evolution of automation and remote access capabilities to distribution stations, the OT environment started to monitor and control distribution assets such that infrastructure tools now support both transmission and distribution. This funding also supports sustainment of cybersecurity tools used across the Hydro One corporate environment, including Intrusion Detection System (IDS) / Intrusion Prevention System (IPS) licences and antivirus programs.
- **Cyber Security Operations**: These expenditures cover managed service provider costs and internal labour related to real-time threat monitoring, proactive testing, and the operation of core security tools. These functions include incident response actions, phishing assessments, SIEM operations, vulnerability management, security information and event management operations, patch management, and threat intelligence. This subprogram was initially planned to account for labour associated with NERC CIP compliance, both cyber and physical, at the control centre and transmission stations. However, since Hydro One consolidated its cybersecurity functions, this has resulted in blended services and labour to support both transmission and distribution. Labour funded under this subprogram now

supports both transmission and distribution assets, as well as Cyber Security Operations for the corporate environment.

Collectively, the consolidation and growth of these two subprograms account for approximately $17M of the increase in General Security's 2028 Test Year expenditures. This amount comprises approximately $13M previously recorded under NERC Security in 2027 and approximately $4M of incremental funding, primarily for expanded real-time cybersecurity monitoring, increased maintenance requirements for infrastructure supporting mission-critical OT environments, and enhanced compliance activities required to address evolving security and compliance requirements.

The remaining $5M increase between General Security's 2027 Bridge Year and 2028 Test Year supports additional internal security capacity and specialized third-party services required to operate and govern Hydro One's expanded security environment. The increase includes security support for technology projects, oversight of security contracts and managed services, regulatory assessments and readiness, security engineering, vulnerability and threat assessment, and assessing future cybersecurity technologies and toolsets. These activities are required to integrate new technology services securely and respond to emerging risk without reducing day-to-day monitoring and response capacity. These functions address growing security threats associated with evolving technologies including AI, quantum computing, and drones.

The overall increases to General Security reflect a material shift in the operating environment, where both cyber and physical threats to critical infrastructure have increased in frequency and sophistication (see exhibits GSP Section 4.11 G-GP-10 Attachment 1, GSP Section 4.11 G-GP-11 Attachment 1, and GSP Section 4.11 G-GP-30 Attachment 1 for additional context). In response, Hydro One is increasing internal staffing to establish and sustain the specialized expertise, governance, and operational accountability required to protect its critical infrastructure and meet expanding compliance obligations. These internal capabilities are necessary to maintain direct accountability for security risk decisions, provide continuous oversight of security controls and third-party

services, retain knowledge of Hydro One's systems and operating environment, and support timely coordination during security events. External providers will continue to supplement these capabilities where specialized expertise or scalable services are appropriate, but they cannot replace Hydro One's responsibility for security governance, risk ownership, regulatory compliance, and operational response.

Hydro One continues to manage these increasing requirements with a focus on operational efficiency and cost mitigation, including initiatives already underway that are expected to continue into the 2028–2032 period. For example, the transition to AI-enabled surveillance systems has improved detection accuracy by reducing false alarms - such as differentiating between wildlife and human intrusion - resulting in fewer unnecessary site dispatches and more efficient use of field resources. Similarly, the establishment of a more integrated monitoring and response model across IT, OT, and network environments has reduced duplication of effort and improved coordination in incident response.

Security and infrastructure capabilities are being further enhanced through unified intelligence and operations, which is expected to improve situational awareness, streamline operations, and reduce reliance on decentralized monitoring activities. In addition, increased use of automation and advanced analytics is expected to improve prioritization of incidents and reduce manual effort associated with monitoring and reporting. While these initiatives contribute to operational efficiencies and help mitigate cost escalation, they also introduce higher ongoing OM&A costs associated with data processing, system maintenance, and vendor-supported platforms.

2.4.2 SECURITY MANAGEMENT

The Security Management function provides enterprise leadership, governance, risk oversight, policy, standards, assurance, and incident preparedness across cybersecurity, personnel security, physical security, and NERC compliance. It establishes the security standards and requirements that operating programs must meet, oversees enterprise security risk and third-party security risk, coordinates incident and recovery planning, and provides assurance that security controls remain appropriate and effective. Activities

include overseeing Hydro One's enterprise security operating model and coordinating security requirements across the company providing advice, coordination and solutions to achieve security standards. This ultimately supports the reliable delivery of electricity, protection of Hydro One's assets, and the continuity or recovery of business functions in the event of a cyber or physical security incident. The costs of common security tools and day-to-day enterprise monitoring are included in General Security, while transmission asset-specific NERC CIP sustainment and compliance execution are included in NERC Security.

The Security Management program is continuously enhanced with new capabilities that are required to meet the following requirements:

- To remain appropriately positioned against an evolving threat landscape that is increasing in complexity and sophistication. This requires Hydro One to augment and deploy new protective technologies and processes to safeguard assets;
- To meet increasing regulatory and legislative requirements, which in turn drive the need for additional security capabilities and compliance requirements;
- To meet the increasing expectations of customers and stakeholders that entrust Hydro One to safeguard their sensitive information; and
- To manage the risks associated with third-party software integrity, vendor personnel security management and third-party connectivity into Hydro One's systems.

2.4.2.1 PROGRAM EXPENDITURES

Table 18 presents Hydro One's total Security Management costs (which are included as part of Hydro One's Corporate Common Costs outlined in Exhibit E-04-02, Section 2.7).

Table 18 - Security Management OM&A Costs ($M)[18, 19]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Security Management	**8.9**	**7.9**	**7.5**	**9.0**	**9.2**	**9.2**
Allocated to Transmission	4.3	3.8	3.6	4.8	4.8	5.0
Allocated to Distribution	4.5	4.0	3.6	4.1	4.2	3.9
Allocated to HOSSM	0.0*	0.0*	0.0*	0.0*	0.0*	0.1
Other	0.1	0.1	0.2	0.1	0.1	0.1

**Values are less than $50k.*

The 2028 Test Year expenditure for Security Management is $9.2M, a $0.3M increase over 2023 actuals, and a $0.7M increase over the average of the last rate period (2023-2027).

The increase in Security Management costs is below the rate of inflation over the 2023-2027 rate period, reflecting Hydro One's efforts to manage costs while maintaining the capabilities required to meet its security requirements. The reduction from 2023 to 2024-2025 is primarily due to organizational restructuring impacting labour and administrative costs. The restructuring of Security Management contributed to maintaining a 1% Compound Annual Growth Rate between 2023 and 2027. Security Management costs are forecast to return to 2023 levels for 2026 to 2028, reflecting the required increased program oversight corresponding to the growing volumes of security events, as well as the expanded monitoring of digital and physical assets.

2.4.3 NERC SECURITY

Hydro One must comply with mandatory physical and cybersecurity standards intended to ensure the integrity and reliable operation of the Ontario Bulk Energy System (BES) and the interconnected North American grid. These requirements are established by the

[18]These costs are not included in the Total Digital & Technology Solutions OM&A presented in Table 1 above. They are considered Corporate Common OM&A costs and are included in the total presented in Table 1 under Exhibit E-04-02.
[19] Figures presented in the table may not sum to the total shown due to rounding.

North American Electric Reliability Corporation (NERC) through its Critical Infrastructure Protection (CIP) standards.

NERC Security OM&A expenditures fund the ongoing maintenance, monitoring, testing, documentation and audit readiness activities required to sustain compliance with these standards. These activities mitigate physical and cybersecurity risks to BES facilities, systems, and equipment. If these systems were to be compromised, it could adversely affect transmission system reliability.

This OM&A program supports security tools and services in the OT environment specifically associated with transmission stations and NERC CIP compliance. The program funds the necessary maintenance and support work required to operate, maintain, and monitor the systems related to Hydro One's NERC Security program, including services provided by external resources. These systems include telecom, physical security, laboratory, central site tools and remote site systems. Hydro One's technical engineering teams also continuously evaluate and test hardware and software components to address compliance issues arising from emerging cyber threats or vendor-initiated changes, such as new features or functionality and hardware modifications.

Additionally, this program funds regular assessments and audits required by NERC CIP standards. Physical and cyber vulnerability assessments verify that implemented security controls have not been intentionally or unintentionally modified, and that Hydro One's assets continue to meet system security management requirements. Threat risk assessments evaluate potential emerging threats and vulnerabilities of Hydro One's transmission stations. The results of these assessments and audits are used to identify control gaps, emerging vulnerabilities, configuration weaknesses, documentation deficiencies, and opportunities to strengthen compliance processes. Assessment findings routinely drive remediation activities, additional monitoring, updates to cyber and physical security controls, and enhancements to compliance evidence and audit readiness activities.

This program also includes compliance-related projects and work triggered by new or revised NERC CIP standards. Funding has been allocated to address any NERC-related continuous improvement investments (identified outside of capital investments) that are required for Hydro One's compliance.

The specific maintenance and support activities within the NERC Security function include:

- Maintaining the various cybersecurity assets (e.g., firewalls, intrusion detection systems, malware detection systems, physical security systems), including third-party contract costs for the maintenance and support of these technologies;
- Monitoring of critical physical facilities, including video surveillance and real-time alarms;
- Conducting vulnerability assessments of critical sites and cyber assets, and security perimeters;
- Managing, operating and monitoring cybersecurity systems (e.g., maintaining personnel access lists, patch management, maintaining logs, updating firmware, periodic tests);
- Tracking the life cycle of critical cybersecurity assets, including proper disposal to ensure the destruction of sensitive information;
- Maintaining physical mapping systems, including patching and updating, setting new monitoring points, and mapping and grouping physical security access points; and
- Conducting ongoing assessments and testing of hardware and software components to ensure compliance.

2.4.3.1 PROGRAM EXPENDITURES

Table 19 below outlines Hydro One's NERC Security expenditures (which are included as part of the Transmission Sustainment OM&A costs presented in Exhibit E-02-02).

Table 19 - NERC Security OM&A Costs[20]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
NERC Security	**18.0**	**20.9**	**23.8**	**23.0**	**22.5**	**11.7**
Allocated to Transmission	18.0	20.9	23.8	23.0	22.5	11.7
Allocated to Distribution	-	-	-	-	-	-
Allocated to HOSSM	-	-	-	-	-	-
Other	-	-	-	-	-	-

The 2028 Test Year expenditure for NERC Security is $11.7M, a $6.2M decrease from 2023 actuals, and a $9.9M decrease from the average of the last rate period (2023-2027).

NERC Security's 2028 Test Year shows a $10.7M decrease from the 2027 Bridge Year. As discussed in Section 2.4.1, above, the decrease does not reflect a reduction in security activities or NERC security-related spending. Rather, approximately $13M associated with the OT Infrastructure Sustainment Contract and Cyber Security Operations subprograms has been transferred to General Security because these activities have evolved to support both Transmission and Distribution security needs. This transfer is partially offset by approximately $2M of additional funding required to expand physical security monitoring services at applicable transmission facilities.

As described in exhibit GSP Section 4.11 G-GP-10, Hydro One is expanding its perimeter security program and replacing end of life physical security devices over the 2028-2032 period. (Additional security sensitive information is provided in the confidential materials associated with exhibit GSP Section 4.11 G-GP-10 Attachment 1.) These investments will establish, strengthen, or renew physical security capabilities such as monitoring, access control, intrusion detection, alarming, and security management. Once placed in service, the additional and renewed equipment requires ongoing monitoring, alarm assessment, escalation, and response coordination to maintain effective physical security and support

[20] These costs are not included in the Total DTS OM&A presented in Table 1. They are included in the Total Transmission Stations Sustainment OM&A, also presented in Table 28 under Exhibit E-02-02.

applicable NERC CIP requirements. The additional OM&A funding supports these recurring operating requirements and is distinct from both the capital cost of installing or replacing physical security assets and the common cyber and OT security activities recorded under General Security.

2.5 TECHNOLOGY MANAGEMENT AND PROJECT CONTROLS

The Technology Management and Project Controls program funds the enterprise-wide management, governance, architecture, planning, procurement support, and delivery controls required to manage Hydro One's IT and OT portfolio.

The program consists of two subprograms:

- **Technology Management:** includes management and senior leadership responsible for the performance, workforce, financial oversight, risks, and outcomes of DTS departments and technology portfolios. It also includes the enterprise architecture team for the development and governance on technology standards. Lastly, it covers data and artificial intelligence governance, technology operations and service-management oversight, strategic vendor oversight, and regulatory support.
- **Project Support and Controls:** includes Supply Chain support for technology procurements, targeted improvements to DTS planning and delivery governance, administration and minor improvements of governance-related tools and associated change efforts to implement and oversee across DTS, and assessment of emerging technologies and business models.

Technology Management and Project Support and Controls fund enterprise-wide accountabilities and controls that cannot reasonably be assigned to a single project, system, or service.

Together, the two subprograms support effective oversight of Hydro One's technology investments and operations. They establish clear accountability, common standards, disciplined procurement and investment decisions, and consistent governance across the technology portfolio.

2.5.1 PROGRAM EXPENDITURES

Table 20 reflects the historical and projected spending for 2023 to 2028.

Table 20 - Technology Management and Project Controls OM&A Costs ($M)[21]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Technology Management	11.5	9.0	10.5	10.8	11.8	16.2
Project Support and Controls	0.6	0.6	0.6	0.7	0.8	3.0
Total Technology Management and Project Controls	**12.1**	**9.6**	**11.0**	**11.6**	**12.6**	**19.2**
Allocated to Transmission	5.3	3.6	3.6	3.8	4.2	7.1
Allocated to Distribution	5.7	4.0	3.8	5.2	6.1	9.9
Allocated to HOSSM	0.0*	0.0*	0.0*	0.0*	0.0*	0.0*
Other	1.0	2.0	3.6	2.5	2.3	2.2

**Values are less than $50k.*

The 2028 Test Year expenditure for Technology Management and Project Controls is $19.2M, a $7.1M increase over 2023 actuals, and a $7.8M increase over the average of the last rate period (2023-2027).

Technology Management

The 2028 Test Year expenditure for Technology Management is $16.2M, a $4.7M increase over 2023 actuals, and a $5.4M increase over the average of the last rate period (2023-2027). The lower costs in 2024 to 2026 are primarily due to organizational restructuring affecting management labour and administrative costs. These reductions were partially offset by the transfer of the Data Governance function from Finance into

[21] Figures presented in the table may not sum to the total shown due to rounding.

DTS to align with the growth of the dedicated Data, Analytics, and AI team. This resulted in Technology Management expenditures increasing approximately 1% annually between 2023-2027.

The increase from $11.8M in 2027 to $16.2M in 2028 is required to provide management and enterprise oversight for Hydro One's expanded technology workforce, work program, and operating environment. The need for these capabilities is increasing as Hydro One's technology environment becomes larger, more integrated, and more dependent on cloud services and external vendors. New and modernized systems, including S/4HANA (see GSP Section 4.11 G-GP-29), cloud platforms (e.g., see GSP Section 4.11, G-GP-05 or G-GP-28), data and artificial intelligence capabilities (see GSP Section 4.11 G-GP-26), enterprise workflow services, and replacement integration technologies, increase the need for coordinated management, architecture, operational governance, and lifecycle oversight.

The proposed capital and prepaid investments, as described across the ISDs summarized in GSP Section 4.11, require additional enterprise architecture resources to maintain technology standards and roadmaps, govern integration patterns, map business capabilities and system dependencies, and assess proposed solutions against Hydro One's target architecture. These activities reduce the risk of incompatible solutions, unmanaged customization, interdependent delivery collisions, duplicative investments, and unmitigated technical debt.

Data, artificial intelligence, automation, and low-code tools create a further increase in governance requirements, and therefore Technology Management funding. Hydro One must maintain policies, standards, decision rights, data ownership, data cataloguing and lineage, quality controls, security requirements, and responsible-use practices. These controls enable adoption while reducing the risk of unmanaged applications, unsupported business processes, data exposure, and inconsistent technology practices.

Project Support and Controls

The 2028 Test Year expenditure for Project Support and Controls is $3.0M, a $2.4M increase over 2023 actuals, and a $2.3M increase over the average of the last rate period (2023-2027). The increase from $0.8M in 2027 to $3.0M in 2028 is required to fund sourcing overhead and support, planning, and delivery controls across Hydro One's expanding technology work program.

The increase supports:

- Supply Chain overhead charges supporting the DTS division in managing technology procurements, including contract negotiations, licence and agreement renewals, service arrangements, and hardware purchases;
- targeted assessments and improvements to project delivery governance, vendor-management practices, investment intake, planning, and prioritization;
- external benchmarking, process reviews, and change-management support for approved governance improvements;
- administration and minor improvements to tools supporting portfolio management, enterprise architecture, demand management, and project delivery; and
- research and assessment of emerging technologies and business models before initiating procurements or projects.

Hydro One's technology portfolio is increasing in scale and complexity, with more interdependent investments competing for specialized resources and affecting common platforms, data, and infrastructure. Continued investment in Hydro One's project delivery governance and toolset (described further in GSP Section 4.10) is required to effectively sequence work within delivery capacity, apply consistent governance, and identify cost, schedule, scope, and operational risks before they affect outcomes. Funding here will also include minor configuration and administrative activities required to support project control processes within tools such as AzureDevOps for demand management, ServiceNow for strategic portfolio governance, or architecture capability models and standard tools such as ArDoq and LeanIX.

The pace of technology change is increasing, particularly with recent advances in artificial intelligence accelerating the development of new industry offerings and innovative solutions. Given this pace of change, DTS requires funding to perform targeted research to assess the potential uses, risks, costs, and implementation requirements of emerging technologies. This research supports the timely review and potential reprioritization of technology investments to meet the operational and delivery needs of the business more effectively. It also improves procurement readiness, enables more effective challenge of vendor proposals, and supports informed investment and architecture decisions.

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OPERATIONS OM&A

1.0 INTRODUCTION

This Exhibit presents the OM&A expenditures required to safely, reliably and efficiently operate Hydro One's transmission and distribution systems. Hydro One's transmission and distribution systems are operated on a 24/7 basis through the Integrated System Operations Centre (ISOC), with the Back-Up Ontario Grid Control Centre (BU-OGCC) providing operational resiliency in the event of a disruption. These facilities and the associated operational technologies enable Hydro One to monitor and control system assets, coordinate planned and unplanned outages, dispatch crews, communicate with customers, plan for and react to system contingencies, and monitor and report on the performance of the transmission and distribution systems.

Operations OM&A supports the people, processes, tools, systems and technology necessary to maintain real-time grid operations, coordinate outages, respond to emergencies, manage operational risk, and meet Hydro One's regulatory obligations in accordance with applicable requirements (including the Transmission System Code, Distribution System Code, IESO Market Rules and NERC/NPCC reliability standards).

Operations OM&A expenditures also support health, safety and environmental (HSE) activities that are required pursuant to Hydro One's regulatory obligations, including the *Occupational Health and Safety Act*.

In addition to supporting day-to-day operations, Operations OM&A supports the sustainment of emerging digital capabilities required to operate an increasingly modernized and distributed electricity system. As customer adoption of Distributed Energy Resources (DER) grows and market participation models evolve, Hydro One requires new operational platforms and capabilities to support DER integration, maintain system reliability and fulfill its evolving responsibilities within Ontario's electricity sector. These new platforms and capabilities are further described in DSP Section 3.11, D-SS-09 Intelligent Grid Platform. Ongoing sustainment of the Intelligent Grid Platform is required

to preserve the operational and customer benefits delivered by these capabilities and to ensure the associated platforms remain effective throughout their lifecycle.

Section 1.1 of this exhibit provides an overview of the overall Operations expenditures, and Section 2.0 provides further details on the underlying programs.

1.1 OVERVIEW OF OPERATIONS OM&A

Operations OM&A expenditures are organized into the following four program areas:

- **Operations** – These costs account for the staff and work activities required to ensure the safe and reliable operation of the transmission and distribution system, including the planning, scheduling and execution of outages, and back-office staffing.
- **Operations Support** – These costs ensure that the various operating computer tools and systems are kept current and functional. This includes the maintenance and support of the modernized distribution system.
- **HSE** – These costs support the HSE initiatives required to meet Hydro One's regulatory obligations and commitments to minimize environmental impact and protect the health and safety of employees, customers and the public.
- **Distributed Energy Resources (DER) Technology Sustainment** – These costs support the ongoing operation of technology assets implemented through capital investments in the Intelligent Grid Platform as outlined in DSP Section 3.11, D-SS-09. These OM&A expenses are required to sustain the functionality, availability, security, and regulatory compliance of the associated digital platforms that enable electricity market participation for DERs.

Table 1 below presents the total forecast Operations OM&A expenditures for the 2028 Test Year and Bridge Year, along with actual and forecast expenditures for the historical years. The total includes costs allocated to Hydro One's Transmission and Distribution businesses.[1]

[1] The allocation of costs between Transmission and Distribution is based on Atrium Economics' Common Corporate Cost Allocation Study provided in Exhibit E-04-08, Attachment 1.

Table 1 - Summary of Total Operations OM&A ($M)[2]

Description	Historical				Bridge	Test	Cost Allocation (Transmission, Distribution, or Common)
	2023	2024	2025	2026	2027	2028	
	Actual	Actual	Actual	Forecast	Forecast	Forecast	
Operations	53.6	59.2	53.5	62.4	62.5	79.2	Common
Operations Support	33.8	35.5	37.0	39.7	39.3	51.6	Common
HSE	3.1	3.4	4.0	5.1	4.5	6.0	Common
DER Technology Sustainment	-	-	-	-	-	1.0	Distribution
Total Operations OM&A	**90.6**	**98.1**	**94.5**	**107.2**	**106.4**	**137.8**	
Allocated to Transmission	49.6	53.9	51.0	57.5	55.8	72.9	
Allocated to Distribution	39.2	42.9	42.2	48.5	49.9	62.1	
Allocated to HOSSM	0.2	0.3	0.2	0.3	0.3	0.3	
Allocated to Other	1.6	1.0	1.1	0.9	0.3	2.5	

The 2028 Test Year expenditure for Operations OM&A is $137.8M, a $47.2M increase over 2023 actuals, and a $38.5M increase over the average of the last rate period (2023-2027).

The proposed $137.8M in total Operations OM&A spending for the 2028 Test Year is required to enable Hydro One to reliably operate the transmission and distribution systems and manage HSE risks, and meet regulatory compliance obligations and customer needs and preferences. The increase is primarily associated with the expansion in operational workload and complexity, the sustainment of operating tools and systems, implementation of the ADMS, evolving HSE requirements, and the introduction of DER Technology Sustainment expenditures.

The allocation between Transmission, Distribution, and HOSSM is largely consistent from 2023 to 2028. The proportion of Transmission-allocated costs decreases slightly from 2023 (55%) to 2028 (53%), while Distribution-allocated costs increase slightly from 2023

[2] Figures presented in the table may not sum to the total shown due to rounding.

(43%) to 2028 (45%). Approximately 0.2% is allocated to HOSSM on average across all years.

Table 2 and Table 3 show the breakdown of the total costs in Table 1 as allocated to Hydro One's Transmission and Distribution businesses, respectively.

Table 2 - Operations Costs Allocated to Hydro One Transmission ($M)[3]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations	25.1	27.5	23.6	28.8	28.4	37.7
Operations Support	22.9	24.6	25.3	26.0	25.0	32.1
HSE	1.6	1.8	2.1	2.7	2.3	3.1
Total Allocated to Transmission	**49.6**	**53.9**	**51.0**	**57.5**	**55.8**	**72.9**

The 2028 Test Year expenditure for Transmission-allocated Operations OM&A is $72.9M, a $23.3M increase over 2023 actuals, and a $19.4M increase over the average of the last rate period (2023-2027). Increases are seen across Operations, Operations Support, and HSE, with the increase in total Transmission-allocated costs primarily driven by increases in Operations and Operations Support.

Table 3 - Operations Costs Allocated to Hydro One Distribution ($M)[4]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Operations	26.7	30.5	28.6	32.5	33.5	38.9
Operations Support	10.9	10.8	11.7	13.6	14.2	19.3
HSE	1.5	1.6	1.9	2.4	2.2	2.9
DER Technology Sustainment	-	-	-	-	-	1.0
Total Allocated to Distribution	**39.2**	**42.9**	**42.2**	**48.5**	**49.9**	**62.1**

[3] Figures presented in the table may not sum to the total shown due to rounding.
[4] Ibid.

The 2028 Test Year expenditure for Distribution-allocated Operations OM&A is $62.1M, a $22.9M increase over 2023 actuals, and a $17.6M increase over the average of the last rate period (2023-2027). Increases are seen across Operations, Operations Support, and HSE, with the increase in total Distribution-allocated costs primarily driven by increases in Operations and Operations Support.

For both Transmission-allocated costs and Distribution-allocated costs, the increase in Operations spend is driven by an FTE increase to sustain a material expansion in operational workload and complexity as described in Exhibit E-06-02 Section 4.3.1 System Operations, and the increase in Operations Support spend reflects increases across Common, Transmission, and Distribution drivers. These trends are further discussed in Section 2.0 below.

2.0 OPERATIONS OM&A PROGRAM DESCRIPTIONS & EXPENDITURES

Hydro One's Operations OM&A expenditures are discussed below for each of the four program areas presented in Table 1: Operations, Operations Support, HSE, and DER Technology Sustainment.

2.1 OPERATIONS

Hydro One operates its transmission and distribution system from a shared facility known as the ISOC. In the event the ISOC or its computer systems become unavailable, back-up operating facilities located at a separate site called the BU-OGCC are activated.

The Operations program within Operations OM&A enables Hydro One to effectively deliver core operational functions that are critical to the level and quality of service delivered to customers in real-time. These functions include scheduling and overseeing planned outages, reacting to unplanned outages, coordinating emergency response, and monitoring system performance.

Between 2026 and 2032, Hydro One's capital investment plan is expected to grow significantly, driving a corresponding increase in outage coordination, real-time system control activities, and planning inputs into Operations.

More field activity means a higher volume of work permits, switching orders, clearances, lockouts, dispatch instructions and real-time communication. This requires Operators to perform more frequent confirmations and safety checks as the operating state of the transmission and distribution system changes more often. This could lead to higher risk of error if workloads spike without corresponding resources and support.

More work also leads to a higher volume of alarms, temporary bypasses or tags, and abnormal equipment states (e.g., open, grounded or locked out). The control room must be able to handle the additional alarms, monitor temporary configurations, and maintain increased updates in logs and operational records. When Operators must track more non-standard system conditions, this can lead to longer pre-job planning cycles and more time spent documenting system states.

Hydro One will continue to bundle outages where possible to reduce overall customer and system impacts. While outage bundling improves efficiency and reduces the number of customer interruptions, outage bundling results in a higher proportion of critical and complex outages that require significantly greater planning, coordination, and execution effort by Operations staff.

Operations also supports increased customer volume and transaction activity, including growth in Transmission-connected customers and obligations under several Operational Services Agreements. These changes have expanded both the scope and intensity of real-time system monitoring, dispatch, and coordination responsibilities.

In addition, Distribution Planning volumes continue to increase as a result of new customer connections and ongoing grid modernization initiatives required to support the Company's distribution strategy. The work program continues to grow year over year,

resulting in increased volumes of work flowing through Distribution Operations. The introduction of the Distribution System Operator Guideline (DSOG), together with a more centralized approach to outage planning, has further increased coordination and workload requirements within Operations.

The Transmission capital work program is also increasing year over year, resulting in a higher number of outages requiring coordination between Transmission and Distribution Operations. Although outage bundling generates efficiencies at a system and customer level, the level of effort required to support and coordinate these outages increases as they become more complex. The Company is also advancing a future-state strategy that emphasizes longer-term outage planning horizons of three to five years, further increasing planning and coordination requirements.

To respond to these increasing demands and improve system performance, Hydro One is implementing a new operating model aligned with the Company's broader distribution strategy and digital enablement initiatives. The revised model separates Operations into two distinct but complementary roles:

- **Distribution Operator** – responsible for operating the real-time distribution system using advanced tools and analytics available through the Advanced Distribution Management System (ADMS), including feeder studies, protection analysis, and system performance monitoring.
- **Outage Operator** – responsible for dispatching and supporting the distribution system during planned and unplanned outages, coordinating closely with field forces and ancillary service providers (including helicopter services), and leveraging ADMS functionality for intelligent dispatching and advanced outage management.

These operating model changes are expected to drive improvements in system reliability and customer outcomes. Further improvements to Distribution System Average Interruption Duration Index (DSAIDI) performance will increasingly depend on enhanced automation and control-room-enabled interventions. The expanded use of intelligent

dispatching, reduced response times to field crews, and increased use of remote switching and feeder study tools are expected to reduce outage duration and customer impact.

Specific Operations functions associated with managing planned and unplanned outages, coordinating emergency response, and monitoring system performance are described in further detail below.

2.1.1 MANAGEMENT AND IMPLEMENTATION OF PLANNED OUTAGES

Successful outage planning is core to Hydro One's business as it seeks to efficiently and safely maintain the transmission and distribution systems while limiting customer interruptions. Planned interruptions are coordinated and managed from the ISOC and typically account for 5% to 15% of the duration of all Hydro One transmission and distribution customer interruptions.

With respect to reliability outcomes explored during customer engagement, reducing the length and number of outages are important priorities across all customer types. Reducing the length of outages not caused by severe weather is within customers' top three priorities.[5] Hydro One's approach for coordinating planned outages to capture efficiencies and mitigate impacts on customers involves:

- Assessing all connected electrical equipment and devices that would be included in outage planning to determine appropriate limits and control actions;
- Assessing forecasted system conditions, system limits, and operating constraints;
- Identifying and notifying customers of upcoming outages through auto-dialer, phone, door-to-door visits, etc., and providing network outage updates to customers via Hydro One's mobile applications;
- For planned outages, addressing customer concerns related to outage times and dates by rescheduling and/or grouping (bundling) planned outages where possible and modifying work scope to restrict the outage in other cases; and

[5] SPF Exhibit B-01-01 Section 1.6 Attachment 1 – JRAP28 Phase 1 Planning Placement

- Complying with all established safety procedures and during outage work activities to ensure the safety of Hydro One staff, customers and the public.

Hydro One's Transmission System Outage Grouping (TSOG) and Distribution System Outage Grouping (DSOG) processes help to enhance outage related services and drive operational efficiencies. Through these processes, Hydro One is able to more effectively communicate and engage with customers, better understand the impacts of the planned outages on customers' operations, and enhance System Operations' ability to provide services that meet customer needs. Improved outage coordination results in a reduction in outage cancellations and annual transmission planned outages.

2.1.2 RESPONDING TO AND MANAGING UNPLANNED OUTAGES

Equipment failures, vegetation contact, road accidents, severe weather, and lightning are among the factors that can result in unplanned service interruptions on the transmission and distribution system. Unplanned outages typically account for a significant majority of Hydro One's total customer outage durations on the transmission and distribution system.

Distribution modernization has challenged how we have traditionally operated. With the rollout of remotely controllable and fault locating equipment on Hydro One's distribution system, System Operations will play a critical role in driving the expected business outcomes.

Furthermore, System Operations has pursued various process improvements. This includes, for example, a Work Protection Decentralization Project, which involves transitioning work protection responsibilities out of the Control Room and into the field. This improves situational awareness and allows Transmission Operators to better focus on system operator specific tasks (i.e., better aligning their duties with the Transmission Operations function).

Hydro One continues to review technologies, processes and best practices to more effectively deliver critical System Operations functions. Consistent with outcomes that

customers value, areas of focus and ongoing improvement include real-time communication with customers, increasing distribution automation (including automatic fault locates and isolation) to minimize restoration times, and optimization of outage duration and operating costs.

2.1.3 EMERGENCY RESPONSE COORDINATION

The Hydro One Emergency Response System is activated in response to widespread interruptions due to weather impacts. The specific responses vary depending on the severity and location of weather events, the number of customers affected, and the expected time to restore service.

During transmission-related emergency events, Transmission Operators activate emergency voltage reduction measures, initiate independent action to mitigate emergent conditions, and/or coordinate and perform routine emergency switching procedures with large generating stations and extra-provincial operating entities.

During distribution-related events, Distribution Operators dispatch crews based on the volume and severity of power-off calls until the command system is switched to Field Operations Centre Dispatch mode. At the Field Operations Centres, supervisors dispatch damage assessment crews and restoration crews at a local level and manage emergency response with firsthand knowledge of the actual problems and more efficient allocation of resources. For larger emergency conditions, which may be more widespread, Incident Command Centres and Forward Command Posts are activated to manage Hydro One's response with the local area command arrangements. Distribution Operators assist with media notifications to inform and update customers, municipalities and other agencies of outage progress and other Hydro One response updates.

2.1.4 SYSTEM PERFORMANCE MONITORING AND REPORTING

Hydro One monitors and reviews system reliability data to identify system performance issues and challenges, and to develop appropriate action plans. System performance reporting is also made available to the OEB. Data required to calculate Hydro One's

reliability indices, such as System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI), is collected at the ISOC.

Outage inquiries from customers and data extracted from the various applications and systems are reviewed to identify emerging performance issues, establish required action plans, and identify opportunities to further improve system performance and minimize customer interruptions. The Customer Operating Support team has placed increased focus on communications with customers, providing system statistics that allow customers to make more informed decisions on investments, outage planning, and operations.

2.1.5 PROGRAM EXPENDITURES

Operations program expenditures for historical, bridge and test years are presented below in Table 4.

Table 4 - Operations Program OM&A Costs[6]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Total Operations	**53.6**	**59.2**	**53.5**	**62.4**	**62.5**	**79.2**
Allocated to Transmission	25.1	27.5	23.6	28.8	28.4	37.7
Allocated to Distribution	26.7	30.5	28.6	32.5	33.5	38.9
Allocated to HOSSM	0.1	0.2	0.1	0.2	0.2	0.1
Allocated to Other	1.6	1.0	1.1	0.9	0.3	2.5

The 2028 Test Year expenditure for Operations OM&A is $79.2M, a $25.6M increase over 2023 actuals, and a $21.0M increase over the average of the last rate period (2023-2027).

Year-over-year variations in the historic actual period (2023-2025) are due to factors such as storm activity, volume of planned outage requests, and unplanned interruptions.

[6] Figures presented in the table may not sum to the total shown due to rounding.

In respect of the 2028 Test Year forecast, Hydro One requires increased funding to deliver the Operations functions described above, including the associated training and capability requirements, and to manage a material expansion in operational workload and complexity. Operations has planned an increase in regular resources to support this growth.

Hydro One's Operations workforce planning is based on demand growth and capital investment, as well as corresponding increases in outage requests, call volumes, alarm management, risk exposure, and compliance obligations. Hydro One's forecast models for both transmission and distribution outages, which have been aligned with 2023-2025 actuals, demonstrate significant growth in the number of annual outages. As a result of these cumulative workload pressures, an FTE increase is required to manage the forecast growth in workload. Exhibit E-06-02, Section 4.3.1 System Operations provides further details regarding the Operations resourcing details.

2.2 OPERATIONS SUPPORT

Operations Support expenditures are required to sustain and enhance the tools, systems and infrastructure that are critical to the reliable and safe operation of Hydro One's transmission and distribution system. These expenditures support compliance with applicable requirements, including the Transmission System Code, the Distribution System Code, IESO Market Rules and NERC/NPCC reliability standards, as well as good utility practice.

Operations Support expenditures for historical, bridge and test years are provided below in Table 5. This level of funding is essential to sustain the ongoing availability and functionality of real-time monitoring and control facilities, systems, and tools that are critical to the overall reliability of the transmission and distribution system.

Table 5 - Operations Support OM&A Costs[7]

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Operations Support	21.4	21.9	23.1	24.3	23.5	30.7
Transmission Operations Support	5.0	6.4	6.1	5.8	5.5	6.6
Distribution Operations Support	7.5	7.2	7.9	9.7	10.3	14.3
Total Operations Support	**33.8**	**35.5**	**37.0**	**39.7**	**39.3**	**51.6**
Allocated to Transmission	22.9	24.6	25.3	26.0	25.0	32.1
Allocated to Distribution	10.9	10.8	11.7	13.6	14.2	19.3
Allocated to HOSSM	0.0*	0.1	0.1	0.1	0.1	0.1
Allocated to Other	-	-	-	-	-	-

**Values less than $50k.*

The 2028 Test Year expenditure for Operations Support OM&A is $51.6M, a $17.8M increase over 2023 actuals, and a $14.5M increase over the average of the last rate period (2023-2027).

Operational tools and systems at the ISOC and BU-OGCC require ongoing maintenance to ensure their functionality and deliver intended benefits. While several factors may drive Operations Support expenditures, product lifecycles and vendor support agreements are the major determining factors for asset maintenance. In adherence to IT industry standard practice, Operations assets are managed through a lifecycle program to ensure the availability of vendor support and minimize the likelihood and impact of failure. Furthermore, the proposed OM&A expenditures fund essential services to support the day-to-day operation of the transmission and distribution system, such as monitoring, controlling and switching, as described in Sections 2.2.1 - 2.2.3 below.

The three subprograms of Operations Support expenditures (Common, Transmission and Distribution) are further discussed below.

[7] Figures presented in the table may not sum to the total shown due to rounding.

2.2.1 COMMON OPERATIONS SUPPORT

Common Operations Support covers several Operating Technology (OT) Operations sustainment functions.

- **Applications Management:** Sustainment for operating tools, including internal labour and third-party software contracts and integration platforms.
- **Infrastructure Management**: Sustainment of OT infrastructure, including network and server environments. This function includes licences, as well as internal labour and support contracts for maintenance, incident response, hardware decommissioning, vulnerability remediation, and associated data center support activities.
- **Data Management**: Sustainment for application support related to data modelling and management, including costs for EMS software suite.
- **Project Management**: Administrative labour, including supervision and training of internal project management personnel, support for investment planning and procurement processes, and financial reporting (including program-level budgeting and forecasting).
- **Service Management**: Internal labour to support grid control operations, administer incident and problem management activities related to service management, enroll and monitor intelligent electronic devices, coordinate data centre-related projects, and maintain the ISOC, BU-OGCC, and Richview data centres.

Additionally, the Common Operations Support program includes certain system operations functions. For example, this program funds minor one-off changes and projects within System Control, as well as funding for ISOC and BU-OGCC sustainment and maintenance. This program also provides funding for the Control Room Scheduling Tool, which schedules operators and supporting roles in the control room.

It also covers various smaller functions, including vendor support for control room interactive voice communications telephony, sustainment costs associated with the crew

call-out platform, and the licence costs for an outage planning visibility and coordination platform.

2.2.1.1 PROGRAM EXPENDITURES

Common Operations Support expenditures for historical, bridge and test years are provided below in Table 6.

Table 6 - Common Operations Support OM&A Costs

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Common Operations Support	21.4	21.9	23.1	24.3	23.5	30.7

The 2028 Test Year expenditure for Common Operations Support OM&A is $30.7M, a $9.3M increase over 2023 actuals, and a $7.8M increase over the average of the last rate period (2023-2027).

Common Operations Support OM&A increases from $23.5M in 2027 to $30.7M in 2028. This increase is primarily driven by the following two cost drivers:

- Approximately $3M of increased spending in core sustainment for operating tools, which includes both internal labour and third-party contracts necessary to sustain operating tools, integration platforms, and Oracle infrastructure. This amount includes $1.3M for incremental FTEs and sustainment support for applications transferred from the emergency preparedness team.
- Approximately $2M of increased spending on grid technology project management, which includes supervision and training of internal personnel, support for business and investment planning, financial reporting, and support for estimating and procurement processes.

2.2.2 TRANSMISSION OPERATIONS SUPPORT

Hydro One relies on several systems, tools, and associated competencies to manage and operate the transmission system. The Transmission Operations Support subprogram

funds services, operating systems and tools that are essential to the planning and execution of transmission outages.

The main Transmission Operations Support subprogram function is field switching for transmission stations and lines, which involves manual field switching of transmission system elements that cannot be remotely controlled. This subprogram ensures that switching function is performed safely in support of planned outages, and supports responses to unplanned outages and third party requests.

Other Transmission Operations Support subprogram functions include:

- **Operating Diagram Maintenance**: Ensures that ongoing changes to transmission system interconnectivity and elements are accurately and promptly reflected on the operating diagrams.
- **Emergency Preparedness**: Ensures the Hydro One Emergency Response Implementation Procedures for the transmission system are updated annually and to ensure emergency communications and backup generator testing are completed.
- **Field Verification**: Supports equipment and print verification required to facilitate incident reporting and ensure diagrams are adequately maintained.
- **Operating Engineering special studies and alarms**: Supports the programs used to investigate specific areas that require further analysis of alarm patterns.

2.2.2.1 PROGRAM EXPENDITURES

Transmission Operations Support expenditures for the historical, bridge and test years are provided below in Table 7.

Table 7 - Transmission Operations Support OM&A Costs

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Transmission Operations Support	5.0	6.4	6.1	5.8	5.5	6.6

The 2028 Test Year expenditure for Transmission Operations Support OM&A is $6.6M, a $1.6M increase over 2023 actuals, and a $0.9M increase over the average of the last rate period (2023-2027). Variations over the 2023-2025 historic actual period were caused by demand for field switching, partially caused by unplanned outages.

The $1.1M increase from the 2027 Bridge Year ($5.5M) to the 2028 Test Year is driven by inflation and growth across Transmission Operations Support subprogram functions as well as the addition of a new Operating Engineering Alarm Optimization function to improve the quality, prioritization, and management of operational alarms presented to grid operators.

2.2.3 DISTRIBUTION OPERATIONS SUPPORT

Hydro One relies on several systems, tools, and associated competencies to manage and operate the distribution system. The Distribution Operations Support subprogram provides funding for services, operating systems and tools that are essential to provide additional monitoring and control, and planning and execution of outages on the distribution system. Furthermore, Distributed Generation penetration on the distribution system will continue to significantly influence system operation and requirements for ongoing support (e.g., changes to station and operating diagrams, data collection activities and updates to the Distribution Management System network model).

The main Distribution Operations Support subprogram function is Control Centre Sustainment. This subprogram covers both sustainment labour and vendor contracts and allows system operators to remotely manage a distribution system enabled with distribution automation. The subprogram supports Hydro One's long-term vision towards a modernized distribution system and provides the following benefits and opportunities:

- Improves the monitoring and management capabilities of the distribution system;
- Enhances the reliability of the distribution system by increasing field crews' situational awareness of the real-time state of the distribution system and location of faults;

- Increases operational efficiencies related to how the distribution system is studied in the planning time frame and provides more real-time operations tools for the control room and field crews;
- Improves the efficiency of distribution load transfer and configuration studies by leveraging the accurate network topology and the state estimation function; and
- Improves efficiency of storm management by providing a real-time weather impact prediction model of the distribution system.

Other Distribution Operations Support subprogram functions include:

- **Data Collection and Information Updates**: Supports the demand category work required to update distribution system connectivity information and gather accurate field information describing equipment additions and changes on the distribution system
- **Distribution Storm Management Customer Satisfaction Surveys**: Conducted to obtain Hydro One customer feedback on measuring planned, unplanned and storm event outage management performance.
- **Field Verification (Distribution)**: Verifies the accuracy of distribution station operating diagrams.
- **Weather Prediction Tool:** Technology solution that reduces outage duration and optimizes crew and equipment utilization by anticipating and preparing for storms.
- **Leveraging Existing Databases**: Cloud-based smart solution that streamlines new DER connections to advance Hydro One's DER enablement strategy and comply with the OEB's Framework for Energy Innovation.
- **Sentient Sensor Technology Subscription**: Modernized electronic recording ammeter tool, including physical sensors and associated cloud-based solution subscription, that collects feeder data for distribution planners.
- **RSA Archer (Business Continuity):** Identifies potential threats and impacts to Operations resulting from emergency events.

2.2.3.1 PROGRAM EXPENDITURES

Distribution Operations Support expenditure for historical, bridge, and test years are provided below in Table 8.

Table 8 – Distribution Operations Support OM&A Costs

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Distribution Operations Support	7.5	7.2	7.9	9.7	10.3	14.3

The 2028 Test Year expenditure for Distribution Operations Support OM&A is $14.3M, a $6.9M increase over 2023 actuals, and a $5.8M increase over the average of the last rate period (2023-2027).

Distribution Operations Support was consistent from 2023 ($7.5M) to 2025 ($7.9M). In 2026, the forecast expenditures in this program increase to $9.7M. This increase was largely driven by integration and ongoing training for a grid outage prediction tool, and the configuration and deployment of an intelligent vegetation management system.

From 2027-2028, the forecast expenditure further increases from $10.3M to $14.3M. This increase is primarily driven by an additional $4.4M in Control Centre Sustainment to support implementation of the ADMS, which comes online in 2028 (see DSP Section 3.11, D-SS-09 for additional information). This increase in spending includes funding for on-call support from internal labour and external vendors in support of the Control Centre.

2.3 HEALTH, SAFETY AND ENVIRONMENT (HSE)

HSE program involves initiatives that are required to meet Hydro One's legal obligations and align with Hydro One's commitments to the safety of its employees, customers, the public and the environment. HSE includes safety, training, and environmental programs.

Safety programs support Hydro One's Health and Safety Policy and Public Safety Policy, and include:

- **Destination Zero:** As part of Hydro One's commitment to becoming the safest and most efficient utility, this subprogram speaks to its belief in eliminating life-altering injuries. The refreshed Health and Safety Plan builds on the strong foundation established through the 2020-2024 Safety Improvement Plan and reflects input from across the organization, including frontline employees, survey results and focus groups. Hydro One is focused on strengthening its safety culture by advancing its capabilities, enhancing operational discipline and keeping safety at the heart of everything it does. Getting to zero life-altering injuries is supported by the introduction of the Safety Absolutes, a set of guiding principles focused on the most critical hazards that could lead to a life-altering injury.
- **Public Electrical Safety**: This subprogram supports public safety education programs to ensure members of the public remain safe. Hydro One plays a critical role in powering the province and keeping Ontarians safe, including hospitals and police, fire, and ambulance services. Establishing trust between the organization and the communities it services fosters behaviours that drive positive outcomes for all stakeholders. The Public Electrical Safety program focuses on topics including the impact of power line contact, proximity to overhead power lines, and danger of tampering with electrical equipment. Education sessions include the Building Safe Communities program, the Hazard Hamlet electrical safety presentations to elementary school children across Hydro One's service territory, and the public safety presentations at various community events.
- **Employee Health and Safety**: This subprogram allows Hydro One to conduct specific employee occupational hygiene monitoring such as indoor air quality, electromagnetic field frequency, noise surveys and assessment of employee exposures to physical, chemical and biological agents.
- **Contractor Safety Management**: This subprogram entails comprehensive HSE reviews to ensure all hired contractors are qualified to carry out work for the Company. Under the *Occupational Health and Safety Act*, Hydro One has a legal duty to take every reasonable precaution to protect workers, including those not directly employed by Hydro One.

- **Health and Safety Management System:** Hydro One conducts maintenance audits to ensure its Management System is meeting the Occupational Health and Safety Assessment Series (OHSAS) standard.

Training subprograms support Hydro One's Health and Safety Policy and include:

- **Employee Health and Safety Learning**: This subprogram ensures employees are educated on safe work practices and are prepared for the potential critical hazards they may face in the field or in the office. E-learning modules are developed and refreshed to enable remote training and allow the timely and cost-effective delivery of required training. Hydro One endeavors to protect the safety of apprentices and future skilled labour by facilitating knowledge transfer from senior staff through alternative training technologies, including the Trades Mentorship Program.
- **Trades Mentorship Program**: Mentors play a crucial role in developing the next generation of safety-minded, skilled tradespeople. A strong mentorship culture promotes trust, thereby increasing safety and engagement. Mentoring is the transfer of knowledge, skills, and expected workplace behaviour from an experienced employee to an apprentice. Mentors help apprentices understand their trade by discussing technical skills, decision making, and working with other groups. Mentors can also provide insight on identifying hazards of the trade and measures to eliminate, control, and protect against those hazards. The impacts of effective mentorship are improved critical thinking skills and performance in apprentices' work and personal lives.
- **Specialized Training**: This subprogram involves specialized training for certain field employees within Operations (i.e. First Aid, CPR, Automated External Defibrillator (AED), Ice and Water Rescue, Human Performance) to ensure that they are able to perform work in potentially hazardous situations.
- **Training Lab Installation/Maintenance**: This subprogram supports the establishment of training labs and the ongoing need to ensure up-to-date technology for training is available for employees.

Environmental subprograms support sustainability, biodiversity and heritage resource management in alignment with Hydro One's Environment Policy, and include:

- **Sustainability**: This subprogram promotes environmental sustainability, manages risks associated with environmental impacts and climate change, and supports Hydro One's commitments in connection with the Canadian Electricity Association's Sustainable Electricity Company designation.
- **Biodiversity**: This subprogram ensures compliance with federal and provincial laws regarding the protection of migratory birds, endangered species, and associated habitat. This involves the development of special treatment requirements for areas containing migratory birds and endangered species. It also involves developing and implementing a system to relay these requirements to staff responsible for developing work programs.
- **Heritage Resource Management**: This subprogram ensures compliance with heritage legislation by supporting studies, company policies and documentation to manage Hydro One's heritage assets.

2.3.1 PROGRAM EXPENDITURES

HSE program expenditures for historical, bridge and test years are presented in Table 9.

Table 9 - HSE Program Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
HSE Program Costs	**3.1**	**3.4**	**4.0**	**5.1**	**4.5**	**6.0**
Allocated to Transmission	1.6	1.8	2.1	2.7	2.3	3.1
Allocated to Distribution	1.5	1.6	1.9	2.4	2.2	2.9
Allocated to HOSSM	-	-	-	-	-	-
Allocated to Other	-	-	-	-	-	-

The 2028 Test Year expenditure for HSE OM&A is $6.0M, a $2.9M increase over 2023 actuals, and a $2.0M increase over the average of the last rate period (2023-2027).

Historic actual costs were consistent in 2023-2024, then increased by $0.6M in 2025. This increase was largely driven by climate adaptation requirement changes. The 2026 forecast is $1.1M higher than 2025 actuals, largely due to the new five-year refreshed Health and Safety Plan and associated costs to raise awareness of the refreshed Plan.

The 2028 Forecast expenditure is $6.0M, which is $0.9M higher than the 2026 forecast, and $1.5M higher than the 2027 Bridge Year forecast. This increase is necessary to support Health and Safety Training programs, including commercial driver training.

2.4 DER TECHNOLOGY SUSTAINMENT

The DER technology sustainment expenditures support the ongoing operation of technology assets implemented through the capital investments described in DSP Section 3.11, D-SS-09 Intelligent Grid Platform, Section 1.3. These OM&A expenditures are required to sustain the functionality, availability, security, and regulatory compliance of the associated digital platforms that enable electricity market participation.

The capital components of these initiatives, described in DSP Section 3.11, D-SS-09 Section 3.0, established the foundational platforms, integrations, and system capabilities. The associated OM&A expenditures fund software licensing, system support, integration maintenance, and specialized operational labour necessary to keep these assets operational and aligned with evolving business processes, technical standards, and regulatory requirements.

The OM&A expenditures described below support the Market Management Platform which is required for Hydro One to enable its role as a DER Coordinator, assigned to local distribution companies by IESO's Enabling Resources Program (ERP). The DER Coordinator is expected to allow eligible customers and aggregators to safely and effectively participate in IESO-administered markets. As a DER Coordinator, Hydro One will need to facilitate access of DERs sited in Hydro One's distribution service territories to the wholesale market.

The Market Management Platform will allow Hydro One to evaluate safety and reliability of the distribution grid upon DER participation and coordinate dispatch signals while managing distribution system constraints and operating requirements. The Market Management Platform is procured as a Software-as-a-Service (SaaS) solution under which Hydro One accesses a hosted service and does not obtain ownership or control of the underlying software. The investment described in DSP Section 3.11, D-SS-09 Section 3.0 funds the implementation activities required to bring the platform to its intended use, while this investment funds the recurring annual SaaS subscription fees.

Continued OM&A investment is necessary to preserve the benefits of the investments described in DSP Section 3.11, D-SS-09, mitigate operational and compliance risks, and ensure Hydro One can continue to support DER adoption and market participation over the 2028-2032 planning period.

2.4.1 PROGRAM EXPENDITURES

DER Technology Sustainment expenditures for historical, bridge and test years are presented below in Table 10.

Table 10 - DER Technology Sustainment OM&A Costs ($M)

Description	Historical				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
DER Technology Sustainment	-	-	-	-	-	1.0
Allocated to Transmission	-	-	-	-	-	-
Allocated to Distribution	-	-	-	-	-	1.0
Allocated to HOSSM	-	-	-	-	-	-
Allocated to Other	-	-	-	-	-	-

The 2028 Test Year expenditure for DER Technology Sustainment OM&A is $1.0M. This is a new program with no expenditures in the current rate period. The phase-in of DER Enablement begins in 2028, at which point the associated OM&A expenditures begin. The

$1.0M of DER Sustainment forecasted for the 2028 Test Year will fund software licensing, system support, integration maintenance, and specialized operational labour.

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COMMON CORPORATE COSTS OM&A – TRANSMISSION COST OF SALES – EXTERNAL WORK

1.0 OVERVIEW

This exhibit details Hydro One Transmission's cost of sales for external work. This external work includes station maintenance activities, engineering and construction work, and other competitive services that are requested by customers and are individually priced. Exhibit D-02-01 describes the categories of external work and the associated revenues in greater detail.

Secondary Land Use (SLU) costs shown in Table 1 represent the directly attributable administration and support costs required to manage SLU activity. The majority of SLU-related costs are recovered through external revenues generated by the program, as described in Exhibit D-02-01, with only a small portion embedded in Common Corporate Costs, as described in Exhibit E-04-02 Section 2.9. Costs for other external service work, including station maintenance, engineering and construction, and other external services, are directly tracked in the same manner as internal work and are described in Exhibits C-09-01 to C-09-04.

Table 1 provides Hydro One Transmission's cost of sales for the 2023-2028 period.

Table 1 - Cost of Sales - Transmission External Work ($M)

	Historic				Bridge	Test
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	F/Cast	F/Cast	F/Cast
Station Maintenance	2.2	2.1	1.2	2.1	2.5	2.5
Engineering & Construction	1.0	1.8	0.4	0.3	0.4	0.4
Secondary Land Use	1.6	3.0	5.1	4.5	4.5	4.0
Other	3.6	2.9	6.6	3.2	6.6	3.0
Total	**8.5**	**9.9**	**13.3**	**10.1**	**14.0**	**9.9**

The proposed 2028 Test Year budget for Transmission External Work is $9.9M. This is $3.4M lower than 2025 actual expenditures of $13.3M and $1.3M lower than the 2023–2027 average of $11.2M. It is also $0.2M lower than the 2026 forecast of $10.1M, and $4.1M lower than the 2027 forecast of $14.0M. The decrease from the 2027 forecast is primarily driven by the Other category of work, as further described below.

2.0 PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

The sections below provide variance analysis for each component comprising the cost of sales associated with external work.

2.1 SECONDARY LAND USE

The SLU program generates revenue by permitting compatible third-party uses on Hydro One's transmission corridors and other lands. These uses include, among others, municipal and private roadways, parking lots, signboards, communication systems, recreational parks and trails, agricultural uses, pipelines, watermains, sewers, and other municipal, transit, and infrastructure occupations. The program requires dedicated administration and support to assess requests, manage agreements, coordinate access, support governance and controllership, and sustain the technology tools used to manage program activity while protecting corridor integrity.

Program revenues are considered together with the directly attributable costs required to administer and support the program. The SLU costs shown in Table 1 represent these directly attributable program and administration support costs. After accounting for these directly attributable program costs, the resulting net revenues are treated in accordance with the external revenue treatment described in Exhibit D-02-01.

As shown in Table 1, SLU costs increased from $1.6M in 2023 to $3.0M in 2024 and $5.1M in 2025. The increase was driven by higher program activity and more complex transactions. Rising land values extended negotiations for new licences and renewals, particularly where proponents faced materially higher licence amounts than under prior arrangements. This increased the effort required to assess requests, manage revised

commercial arrangements, and administer a higher volume of proponents and transactions. The program also required additional staffing, governance, controllership, and technology tools to support agreement management, access coordination, and corridor integrity.

The proposed 2028 Test Year budget for SLU costs is $4.0M. This is $1.1M lower than 2025 actual expenditures of $5.1M, $0.5M lower than the 2026 forecast of $4.5M, and $0.5M lower than the 2027 forecast of $4.5M. The decrease from 2025 reflects a moderation of higher program support costs associated with elevated transaction volumes and more complex agreement negotiations experienced during the 2023-2025 period. As transactions and costs related to establishing and renewing agreements normalize, the 2028 forecast continues to support the ongoing administration and sustainment of SLU activity.

2.2 STATION MAINTENANCE

Costs for station maintenance are directly related to the volume of work performed by Hydro One to support Ontario's key generating suppliers: Ontario Power Generation Inc., Siemens Westinghouse Inc. and Bruce Power LP. The proposed 2028 Test Year budget for Station Maintenance is $2.5M. This is $1.3M higher than 2025 actual expenditures of $1.2M, $0.4M higher than the 2026 forecast, and consistent with the 2027 forecasts of $2.5M. The forecast reflects the expected volume of station maintenance work performed by Hydro One.

2.3 ENGINEERING AND CONSTRUCTION

Hydro One's engineering and construction activities focus on work supporting Acronym Solutions Inc. (Acronym Solutions), formerly Hydro One Telecom Inc. In particular, Hydro One supports Acronym Solutions customer requests for new interconnections with Hydro One's optical fibre infrastructure by providing design, quote, and build services related to Acronym Solutions work within Hydro One's transmission station property.

Costs for engineering and construction are directly related to the volume of work performed by Hydro One to support Acronym Solutions operations. The proposed 2028 Test Year budget for Engineering and Construction is $0.4M. This is consistent with 2025 actual expenditures of $0.4M and the 2027 forecast of $0.4M, and $0.1M higher than the 2026 forecast of $0.3M.

2.4 OTHER

The Other category includes costs for work performed for Hydro One's affiliates, such as B2M and NRLP, as well as other miscellaneous external work. The proposed 2028 Test Year budget for Other external work is $3.0M. This is $3.6M lower than 2025 actual expenditures of $6.6M, $0.2M lower than the 2026 forecast of $3.2M, and $3.6M lower than the 2027 forecast of $6.6M.

The year-over-year fluctuations are primarily attributable to Transmission Line Maintenance and Vegetation Management activities on the B2M corridor. Transmission Line corrective maintenance is dependent on the availability of system outages. When planned outages are cancelled or deferred, the associated work is typically rescheduled to a subsequent year, contributing to the higher expenditures in 2025 and forecast for 2027.

For Vegetation Management, major maintenance activities are performed on a six-year cycle. The 2027 forecast reflects a higher concentration of scheduled work, while the lower 2028 Test Year forecast reflects the remaining scope, primarily comprising smaller projects, unplanned maintenance activities and NERC patrol requirements.

Overall, expenditures in this category vary with the timing and the volume of work performed by Hydro One for its affiliates and other external parties.

COMMON CORPORATE COSTS OM&A – DISTRIBUTION COST OF SALES – EXTERNAL WORK

1.0 OVERVIEW

This Exhibit details Hydro One Distribution's costs associated with regulated and unregulated external revenues that are not included in other OM&A programs. Regulated revenues are based on OEB-approved specific service charges, which are detailed in Exhibit L-04-01. Unregulated revenues and the associated charges are described in Exhibit D-02-02, which presents the associated external revenues over the 2028 to 2032 period.

In this Exhibit, the Cost of Regulated Revenue consists primarily of costs associated with new connections of subdivision and rural residential facilities, service upgrades to increase supply capacity, streetlight maintenance, and forestry work. The Cost of Unregulated Revenue includes costs associated with storm restoration; Hydro One Remotes transport work equipment used for emergency services and Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) training and development.

Table 1 sets out planned expenditures for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge Year (2027) and Historical Period (2023-2026) for the Distribution Cost of Sales.

Table 1 - Summary of OM&A Costs of External Revenue ($M)[1]

	Historical				Bridge Year	Test Year
	2023	**2024**	**2025**	**2026**	**2027**	**2028**
	Actual	**Actual**	**Actual**	**Forecast**	**Forecast**	**Forecast**
Cost of Regulated Revenue	1.6	3.1	3.3	1.1	1.1	(0.9)
Cost of Unregulated Revenue	3.9	15.0	15.1	3.4	3.5	3.7
Total	**5.5**	**18.1**	**18.4**	**4.5**	**4.7**	**2.7**

[1] Figures presented in the tables may not sum to the totals shown due to rounding

The 2028 test year expenditure for Distribution Cost of Sales OM&A is $2.7M, a $2.8M decrease from 2023 actuals, and a $7.5M decrease below the average of the last rate period (2023-2027). The historical actuals reflect costs of unregulated revenue related to storm support in 2024 and the replacement of Bell-owned poles following the 2025 ice storm. Due to their unpredictable nature, these costs are not included in the forecasts, leading to a decrease between historical actual and forecast costs. Beginning in 2028, costs decrease due to a higher allocation credit resulting from the Atrium study (see E-04-08 Attachment 1) and a lower forecast of new connections, resulting in a net credit (negative cost).

2.0 PROGRAM DESCRIPTIONS & VARIANCE DISCUSSION

2.1 COST OF REGULATED REVENUE PROGRAM INTRODUCTION

The cost of Regulated Revenue consists of miscellaneous services such as customer new connects and service upgrades, streetlight maintenance and forestry work.

EXPENDITURE FORECAST LEVEL

Table 2 sets out planned expenditures for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge Year (2027) and Historical Period (2023-2026) for Cost of Regulated Revenue.

Table 2 - Cost of Regulated Revenue OM&A ($M)[2]

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Cost of Regulated Revenue	1.6	3.1	3.3	1.1	1.1	(0.9)

The 2028 Test Year expenditure for Cost of Regulated Revenue OM&A is ($0.9M), a $2.5M decrease below 2023 actuals, and $2.9M below the average of the last rate period (2023-2027).

[2] Figures presented in the tables may not sum to the totals shown due to rounding

The forecast expenditure is based on the levels of forecasted customer connections and joint use services, which consists of construction activities and vegetation management. Given the demand nature of this work, forecasts are based on historical volumes.

From 2023 to 2025, the increase in the cost of regulated revenue was primarily driven by higher new connections and upgrade costs and increased joint use and relocation costs. Forecast costs in 2026 and 2027 are slightly lower than 2023 actual levels due to a reduction in expected new connection activity. Beginning in 2028, costs decline as a result of a higher allocation credit from the updated Atrium study and a lower new connections forecast, resulting in a net credit (negative cost). The negative cost reflects the recovery of common asset costs, including SAP and computer software, that are allocated from the transmission and distribution businesses to affiliate segments.

2.2 COST OF UNREGULATED REVENUE PROGRAM INTRODUCTION

The cost of Unregulated Revenue is comprised of costs associated with Hydro One Remotes transport work equipment usage on emergency services, MEARIE training and development and storm support.

EXPENDITURE FORECAST LEVEL

Table 3 sets out planned expenditures for the 2028 Test Year, along with the forecast and actual spending levels for the Bridge Year (2027) and Historical Period (2023-2026) for Cost of Unregulated Revenue.

Table 3 - Cost of Unregulated Revenue OM&A ($M)[3]

	Historical				Bridge Year	Test Year
	2023	2024	2025	2026	2027	2028
	Actual	Actual	Actual	Forecast	Forecast	Forecast
Cost of Unregulated Revenue	3.9	15.0	15.1	3.4	3.5	3.7

[3] Figures presented in the tables may not sum to the totals shown due to rounding

The 2028 Test Year expenditure for Cost of Unregulated Revenue is $3.7M, a $0.2M decrease below 2023 actuals, and $4.5M below the 2023-2027 average.

The cost of Unregulated Revenue varied over the historic actual period. The 2024 cost of Unregulated Revenue reflects deployments in response to Hurricane Helene and Hurricane Milton. The 2025 cost of Unregulated Revenue reflects the cost of pole replacements following the spring ice storm.

Forecast expenditures are consistent from 2026-2028. These expenditures are based on the levels forecasted for MEARIE training and Hydro One Remote operations, of which work equipment usage for Remote work contributes to the majority of expenditures. The forecast is informed by Hydro One Remotes to complete annual vegetation and line maintenance activities and corresponding fleet requirements. Storm support is unpredictable and dependent on Hydro One's ability to deploy storm relief to outside jurisdictions and, accordingly, is not included in the forecast.

COMMON CORPORATE COSTS & ALLOCATION METHODOLOGY

1.0 INTRODUCTION

Hydro One defines Common Corporate Costs as costs incurred to provide service on a shared basis to Hydro One Networks and its affiliate companies. Examples of Hydro One's shared functions include, but are not limited to, Finance, Human Resources, General Counsel, Planning, and Regulatory Affairs. The provision of these services is centralized to enable them to be delivered to Hydro One Networks and its affiliates efficiently. In addition to the need to allocate Common Corporate Costs between Hydro One Networks and its affiliate companies, for those Common Corporate Costs that are allocated to Hydro One Networks there is a further need to allocate Common Corporate Costs to the Distribution and Transmission business segments.

Hydro One uses a Common Corporate Cost allocation methodology to allocate these costs among affiliates and business segments. A list of Hydro One's affiliates and business segments can be found in Table 4 of Attachment 1 to this exhibit. To the extent that these costs cannot be directly assigned and charged to a particular affiliate or business segment, Common Corporate Costs are allocated either on the basis of cost drivers (e.g., HR is allocated based on headcount) or on the basis of time surveys and time studies (e.g. interviews and time tracking studies). The purpose of the allocation process is to ensure that affiliates and business segments each share a portion of the cost that is appropriate for the level of service they receive.

Common Corporate Costs can be incurred in support of both OM&A work and capital work. Consequently, it is necessary to allocate some Common Corporate Costs to capital work. This is completed through the application of an Overhead Capitalization Rate, which is an additional charge on capital work to recover a portion of Common Corporate Costs that is commensurate with the level of service provided on a shared basis in support of that capital work. Exhibit C-08-02 covers the Overhead Capitalization Rate in greater detail.

For greater clarity, in instances when costs can be directly attributed to OM&A or capital work for an affiliate or business segment for a sustained period of time, those costs are assigned directly to the relevant affiliate or business segment in connection with the specific OM&A or capital work that is being completed. These direct costs are excluded from Hydro One's Common Corporate Cost Allocation Methodology because they are assigned or transferred to the relevant affiliate or business segment prior to calculating the total Common Corporate Costs that are considered in the allocation methodology. Any costs that are not billed directly are subject to the Common Corporate Cost Allocation Methodology.

Common Corporate Costs as defined by Hydro One include the provision of Common Corporate Functions and Services (CCF&S) costs (Exhibit E-04-02) and portions of Customer Care costs (Exhibits E-02-04 and E-03-04), Planning costs (Exhibit E-04-03), System Operating (Operations) costs (Exhibit E-04-05) and Digital Technology System costs (Exhibit E-04-04).[1]

2.0 ALLOCATION METHODOLOGY

Since 2004, in connection with each rate application for Transmission and Distribution, Hydro One has engaged an independent expert to prepare a Common Corporate Cost Allocation Study to recommend a best practice methodology for allocating common corporate costs among the affiliates and business entities which receive services from the shared functions, and to provide a report setting out their findings and recommendations.

The initial Common Corporate Cost Allocation Methodology was developed for Hydro One by Black and Veatch Corporation (B&V) in 2004. B&V was routinely engaged by Hydro One in subsequent proceedings to refine the previously approved methodology on a go-forward basis. This methodology was utilized and subsequently endorsed by the OEB in each of the following Transmission revenue requirement proceedings: EB-2006-0501; EB-

[1] System Operating (Operations) Costs as presented in Exhibit E-04-05 and Customer Care Costs as presented in Exhibits E-02-04 and E-03-04 are not part of Summary of Common Corporate Costs presented in Exhibit E-04-01.

2008-0272; EB-2010-0002; EB-2012-0031; EB-2014-0140; EB-2016-0160; EB-2019-0082; and EB-2021-0110; as well as in each of the following Distribution rate proceedings: RP-2005-0020; EB-2005-0378; EB-2007-0681; EB-2009-0096; EB-2013-0416; EB-2017-0049; and EB-2021-0110.

The Corporate Cost Allocation Review was conducted to fulfill a commitment established in the EB-2021-0110 Settlement Proposal.[2] Hydro One selected Atrium Economics (Atrium) to conduct an independent assessment of the Company's Common Corporate Cost Allocation Methodology, Overhead Capitalization Methodology, and the methodology used to allocate Shared Asset costs among regulated business units and affiliates. Atrium was selected based on its expertise in utility cost allocation and regulatory matters, as well as its familiarity with Hydro One's operations and regulatory framework. Atrium was mandated to comprehensively review the existing methodologies, critically assess current practices, and identify refinements where appropriate based on industry best practices. The resulting review, filed in this Application, fulfills the commitment by providing an independent assessment of Hydro One's corporate and Shared Asset cost allocation methodologies.

Atrium has conducted a critical review of the methodologies and recommended refinements, where appropriate, as described in Section 4.4, "Updates to Methodology in 2026," of the Corporate Cost Allocation Update (Atrium Study) provided in Exhibit E-04-08, Attachment 1. Examples of these refinements include:

- developing allocation factors for each plan period to reflect the changing relative relationships among affiliates arising from the expected growth and evolution of the joint ventures over the course of the plan period;
- using a three-year average of program and project costs allocator instead of one-year to better reflect the effort associated with certain long-term planning activities;

[2] In its Settlement Proposal in EB-2021-0110, Appendix A, *Studies, Reports and Reporting*, the OEB required Hydro One to undertake and file a Corporate Cost Allocation Review as part of its next cost-based rate application.

- using a joint venture portfolio as a pre-allocator factor to ensure that subsequent distributions of corporate resources to transmission entities reflect a more stable, equitable, and representative measure of corporate support; and
- assessing IT contract costs to support capital-related activities.

The conclusions and results of the Atrium Study are outlined on page 28 of the report.

The three studies performed by Atrium are related, and to some extent, dependent on each other, as they utilize common drivers underpinned by the principles of cost causation. Common Corporate Costs are allocated to the affiliates and business units using the Common Corporate Cost Allocation Methodology, and applicable costs are then allocated to capital work via overhead rates, set by the Overhead Capitalization Methodology (see Exhibit C-08-02). The Shared Assets rates are determined using the output of the study and are used to allocate assets between Transmission and Distribution (see Exhibit C-03-01).

As part of the Atrium Study, and consistent with its prior practice in supporting Hydro One rate applications, detailed interviews were conducted by Atrium for all common corporate departments in order to update the services provided and cost drivers used to allocate the common corporate costs in prior proceedings.

Hydro One accepts the results of the Atrium Study as a reasonable and fair approach to the allocation of common corporate costs among the affiliates and business segments using the services of the shared functions. This recommended approach is largely based on the methodology employed in prior studies and accepted by the OEB in numerous Distribution and Transmission rate decisions (see Appendix A of Attachment 1 to this exhibit).

3.0 2027 BRIDGE YEAR ALLOCATED AMOUNTS

Table 1 below provides the annual allocation of 2027 bridge year CCF&S costs to all business units by department.

Table 1 - Allocation of 2027 Bridge Year CCF&S Costs ($M)

	Total	Transmission	Distribution	HOSSM	Other
Corporate Management	36.7	3.8	6.3	0.03	26.6
Finance	24.5	8.6	11.5	0.16	4.2
Human Resources	53.5	23.4	25.1	0.08	5.0
Corporate Affairs	27.4	9.6	12.1	0.12	5.6
General Counsel	17.0	9.6	5.4	0.23	1.8
Regulatory Affairs	31.3	15.8	14.1	-	1.3
Security Management	9.2	4.8	4.2	0.05	0.1
Internal Audit	8.5	3.4	4.3	0.01	0.8
Facilities and Real Estate	64.7	34.3	30.0	0.02	0.3
Total CCF&S Costs[3]	**272.8**	**113.3**	**113.0**	**0.7**	**45.8**

4.0 2028 TEST YEAR ALLOCATED AMOUNTS

Table 2 below provides the annual allocation of 2028 test year CCF&S costs to all business units by department.

Table 2 - Allocation of 2028 Test Year CCF&S Costs ($M)

	Total	Transmission	Distribution	HOSSM	Other
Corporate Management	35.7	3.9	6.2	0.09	25.5
Finance	25.9	10.8	12.1	0.10	2.9
Human Resources	58.6	34.2	18.6	0.02	5.8
Corporate Affairs	31.6	12.6	14.2	0.21	4.6
General Counsel	16.8	6.3	5.7	0.07	4.7
Regulatory Affairs	35.4	22.5	10.0	0.23	2.7
Security Management	9.2	5.0	3.9	0.09	0.1
Internal Audit	9.1	3.9	4.0	0.04	1.1
Facilities and Real Estate	80.9	39.6	40.8	0.04	0.5
Total CCF&S Costs[3]	**303.2**	**139.0**	**115.5**	**0.9**	**47.8**

The amounts allocated to Other in Tables 1 and 2 above reflect costs allocated to Hydro One Inc., Hydro One Limited, Hydro One Networks non-regulated segment, Hydro One

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

Remotes, B2M, NRLP, CLLP and other non-regulated segments. Hydro One has excluded from its request for recovery in this application any costs that have not been allocated to Hydro One Networks' Transmission and Distribution business segments (as well as any costs continue to be excluded on the basis of the historical *Hydro One Accountability Act, 2018* (Bill 2)).

5.0 VARIANCE ANALYSIS

Variance analysis with explanations is provided in Exhibit E-04-02 for CCF&S, Exhibit E-04-03 for Planning, Exhibit E-04-04 for Information Solutions, Exhibit E-02-04 and Exhibit E-03-04 for Customer Care and Exhibit E-04-05 for System Operating (Operations).

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Hydro One Networks Inc.

2028 Corporate Cost Allocation Review

September 10, 2026

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1. Summary

1.1 Purpose and Organization of Report

Atrium Economics, LLC ("Atrium Economics") was retained by Hydro One Networks, Inc. ("Hydro One") to review Hydro One's Corporate & Shared Cost Allocation Methodology in connection with its rebasing application for approval of Transmission and Distribution rates for 2028-2032. Atrium's review assessed whether the methodology remains appropriate in light of Hydro One's current organizational structure and operations, relevant Ontario Energy Board ("OEB") requirements, and generally accepted regulatory cost allocation practices, and identified refinements where warranted. Martha Davis, Managing Consultant, served as Project Manager and, together with John Taylor, CEO, provided subject-matter expertise for the review, with support from Kara Hounam, Consultant.

In the Ontario Energy Board's ("OEB") April 23, 2020 Decision and Order in the matter of Hydro One's Transmission revenue requirement for 2020-2022 (EB-2019-0082), the OEB indicated that, as part of Hydro One's rebasing application for Transmission and Distribution rates for 2023-2027, it intended to examine Hydro One's Corporate & Shared Cost Allocation Methodology in detail. The 2021 Evaluation was filed in response to the OEB's direction in EB-2019-0082 and served as the basis for the methodology reviewed in Hydro One's 2023-2027 Transmission and Distribution rate application.

Additionally, as part of the Settlement Proposal in Hydro One's Transmission and Distribution rate application for 2023 to 2027 (EB-2021-0110), the OEB indicated that Hydro One shall submit an independent third-party Corporate Cost Allocation Review as part of its next cost-based rate application. Hydro One agreed to submit an independent third-party Corporate Cost Allocation Review as part of its next cost-based rate application. This report has been prepared in response to that requirement. Atrium's review considered whether Hydro One's existing methodology and its principal components remain appropriate for the 2028–2032 period and identifies refinements recommended as a result of that review.

Hydro One's Corporate & Shared Cost Allocation Methodology, as reviewed and refined through prior regulatory proceedings, includes three principal components: (1) a methodology to allocate Hydro One's common corporate operation, maintenance, and administrative ("OM&A") costs ("common corporate costs"); (2) a methodology for capitalizing a portion of Common Corporate Costs for the Transmission ("Tx") and Distribution ("Dx") businesses; and, (3) a methodology to allocate the use of shared assets. Overall, the methods employed across these three components are described collectively as Hydro One's Corporate & Shared Cost

Allocation Methodology. Common corporate costs are those costs incurred to provide shared corporate services to Hydro One and its affiliated companies.

Atrium's review of Hydro One's Corporate & Shared Cost Allocation Methodology began in December 2025 and continued through June 2026. The review focused on assessing whether the methodology continues to distribute costs in a manner consistent with OEB precedent and generally accepted regulatory cost allocation practices while appropriately reflecting Hydro One's current organizational structure and the operational realities of how services are provided across the business.

Consistent with Atrium Economics' standard practice for consulting assignments, we relied on the genuineness and completeness of all documents presented to us by Hydro One, and we accepted factual statements made to us by Hydro One (e.g., headcount, budgeted amounts) subject only to their overall reasonableness and factual accuracy, but without our independent confirmation.

1.2 Scope of Review

Atrium Economics' review was conducted with reference to select provisions of the Ontario Energy Board's Affiliate Relationships Code for Electricity Distributors and Transmitters (the "Affiliate Relationships Code"). As outlined in Appendix B, our analysis focused on the definitions and sections of the ARC that relate to the identification, classification, and allocation of costs, particularly those pertaining to fully allocated costs associated with shared corporate services.

Consistent with this scope, Atrium Economics' work was limited to evaluating the methodology for allocating Hydro One's fully allocated costs across affiliated entities. This included an assessment of whether cost categories were appropriately defined and whether allocation approaches were reasonable, transparent, and aligned with the cost allocation principles embedded in the Affiliate Relationships Code.

Importantly, this review did not assess whether a reasonably competitive market exists for any of the services provided, nor did it evaluate or benchmark market prices for those services. While the Affiliate Relationships Code includes provisions governing transactions in which market prices apply, those provisions were referenced solely for contextual completeness and to delineate the broader regulatory framework. Atrium Economics did not perform a market study, pricing analysis, or comparability assessment with third-party providers.

Accordingly, the conclusions presented in this report should be understood as limited to the appropriateness of the cost allocation methodology for shared corporate services and other centrally held costs within Hydro One, rather than as an evaluation of transfer pricing outcomes

under market-based standards. In addition, the review is not an audit, validation, or assurance review of Hydro One's calculation systems, accounting systems, or computational tools used to implement the methodology.

Atrium focused its review on evaluating the continued appropriateness of the methodology and identifying changes that may be warranted due to changes in Hydro One's business, governmental or regulatory requirements, available information, technology, or other relevant considerations. Where the review identified a more appropriate allocation approach or driver, Atrium recommended refining the methodology.

Hydro One updated the allocation factors used in the methodology to reflect its current organizational structure, business activities, and the most recent available data. Atrium reviewed the updated allocation factors for reasonableness and consistency with the applicable cost allocation principles and recommended refinements where warranted. The resulting allocation factors support application of the methodology across the 2028–2032 planning period and allow the allocations to reflect changes in business activity over time.

The general methodology used by Hydro One in 2021 has been consistently applied in subsequent Business Plans. The purpose of this report is to document Atrium's review, the refinements identified through that review, and the methodology Hydro One proposes to apply for the 2028–2032 period.

1.3 Components of Hydro One's Corporate & Shared Cost Allocation Methodology

The three components of Hydro One's Corporate & Shared Cost Allocation Methodology are described below.

1.3.1 Allocation of Common Corporate Costs

Common Corporate Costs are incurred to provide Shared Services to Hydro One and its affiliate companies. The provision of these Shared Services is centralized, so costs need to be allocated across the various affiliates using either cost drivers (e.g., certain Human Resources costs are allocated based on company headcount) or time surveys (e.g., interviews with company personnel). The purpose of these allocations is to ensure no cross-subsidization between affiliates nor between the Tx and Dx businesses by allocating Common Corporate Costs in accordance with the level of services being received.

An overview of the methodology is described below:

- Through interviews with Hydro One personnel, identify the Shared Services included in Common Corporate Costs and the particular activities performed to provide these Shared Services.
- Through interviews with Hydro One personnel, time surveys, and analyses of time spent by employees, distribute the costs of each Shared Service among the activities performed by that Line of Business to provide that Shared Service.
- Distribute the cost of each activity among Hydro One, its affiliate companies, and between the Tx and Dx businesses based on direct assignment (see **Section 3.3**) or on cost drivers (see **Section 3.4**) when direct assignment is not possible.

Further, in instances when costs associated with Common Corporate Costs can be directly attributed to work for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers. These costs are not included in Hydro One's Corporate & Shared Cost Allocation Methodology because they are recorded and transferred before determining the total Common Corporate Costs included in the allocation methodology.

1.3.2 Capitalizing Common Corporate Costs for Tx and Dx Businesses

Common Corporate Costs support both OM&A expenditures and capital expenditures; so there is a need to distinguish further Common Corporate Costs between those that (a) only support OM&A expenditures, (b) directly support capital expenditures, and (c) are overhead costs that support both OM&A expenditures and capital expenditures. Those costs that directly support capital expenditures, and a portion of the overhead costs that support both OM&A and capital expenditures, are recovered from capital expenditures through an Overhead Capitalization Rate. This rate is an additional charge on capital expenditures to recover Common Corporate Costs in proportion to the amount of Shared Services used to support those projects. Costs that only support OM&A expenditures are excluded from this calculation.

The general methodology employed is first to review Shared Service activities to ascertain whether the activity directly supports OM&A, directly supports capital, or supports both capital and OM&A. Second, costs that support both capital and OM&A are split between OM&A and capital. Third, the resulting capitalized common corporate costs are used by Hydro One to calculate the Overhead Capitalization Rate applied to capital expenditures.

1.3.3 Allocation of Shared Assets

As part of the review, Hydro One updated the Shared Asset information to reflect current asset balances, additions, and relevant usage, including updates to asset categories such as Aircraft and Fleet. Atrium reviewed the resulting Shared Asset allocations to assess whether the allocation methods and drivers remained appropriate in light of the nature of the assets, the

Shared Services they support, and how Hydro One, its Affiliates, and the Tx and Dx businesses use them. Hydro One also included Prepaid Cloud Computing Implementation and Amortization Costs associated with in-service projects within the Shared Asset information. Atrium reviewed the appropriate allocation treatment for those costs and recommended using the Program and Project Costs driver. The resulting Shared Asset allocations support the development of the Tx and Dx revenue requirements and transfer pricing associated with affiliate use of Shared Assets.

1.4 Executive Summary

Atrium Economics conducted an independent third-party review of Hydro One Networks Inc.'s ("Hydro One") Corporate & Shared Cost Allocation Methodology to assess whether the methodology continues to be reasonable, is consistent with Ontario Energy Board ("OEB") requirements, and aligned with generally accepted regulatory cost allocation practices.

Based on our review, Atrium concludes that Hydro One's Corporate & Shared Cost Allocation Methodology remains appropriate for its intended purpose. Specifically, the methodology:

- Allocates costs in a manner consistent with the principle of cost causation and, where appropriate, benefits received
- Is consistent with the relevant provisions of OEB's Affiliate Relationships Code and prior regulatory precedent
- Avoids cross-subsidization among affiliates and between the Transmission ("Tx") and Distribution ("Dx") businesses
- Produces transparent, stable, and reproducible results suitable for regulatory review.

The current review supports retaining the core framework used in prior periods, with targeted refinements to reflect changes in Hydro One's organizational structure, business activities, and available data. These refinements improve the accuracy, transparency, and forward-looking applicability of the methodology without altering its fundamental design.

1.4.1 Key Enhancements Identified Through the Current Review

The principal refinements identified through the current review are:

- **Allocation Factors by Plan Year:**
  Allocation factors have now been developed for each year of the plan period (2028–2032), enabling the methodology to reflect changes in the relative size, activity levels, and cost drivers of Hydro One's affiliates and business segments over time.
- **Refinement of Program and Project Cost Driver:**
  A three-year average of Program and Project Costs is now used to drive certain allocations. This approach better reflects the multi-year nature of planning, capital development, and associated support activities and reduces volatility from single-year measures.

- **Treatment of Joint Venture Affiliates:**
  As part of this 2028 review, Atrium reviewed Hydro One's approach for allocating common corporate costs to existing and future joint venture Transmission affiliates. For purposes of determining the overall level of common corporate costs attributable to the joint venture portfolio, the methodology treats the joint venture entities collectively to reflect the shared nature of corporate support activities and the expectation that the portfolio of joint venture entities will continue to evolve over the 2028-2032 planning period. After costs are allocated to the joint venture portfolio, Hydro One separately allocates those costs among the individual joint venture entities using allocation factors appropriate to each entity. This approach allows the methodology to accommodate the addition of future joint venture entities while maintaining separate cost attribution and regulatory accountability for each individually regulated entity.
- **Inclusion of IT Third-Party Contracts:**
  Third-party IT contracts, including enterprise software and cloud-based platforms, are incorporated into the cost allocation and overhead capitalization framework, where they support capital-related activities. This treatment is consistent with the increasing reliance on technology to plan, design, and execute capital projects and aligns with regulatory principles of cost causation.
- **Inclusion of Prepaid Cloud Computing Costs in Shared Assets:**
  Prepaid cloud computing implementation and amortization costs are included within Shared Assets and allocated using Program and Project Cost drivers. This approach reflects the functional role of these assets in supporting both operational and capital activities.

1.4.2 Summary of Results

Hydro One applied the Corporate & Shared Cost Allocation Methodology to its Business Plan data. The results demonstrate that:

- The distribution of Common Corporate Costs among Tx, Dx, and Other businesses remains generally consistent with prior studies, with variations reflecting expected changes in organizational structure and business focus
- The Overhead Capitalization Rates for Tx and Dx remain within a reasonable range and consistent with prior outcomes
- The allocation of Shared Assets continues to appropriately reflect usage across businesses, with no material shifts that would indicate distortion or bias

Overall, the results confirm that the methodology continues to produce reasonable and stable allocations that are aligned with regulatory expectations.

1.4.4 Summary Tables of Corporate & Shared Cost Allocation Methodology

Hydro One's Corporate & Shared Cost Allocation Methodology has been applied to its 2028 Business Plan data, and the results for the three components are presented below.

Table 1 - Distribution of Annual Common Corporate Costs for Ratepayer Recovery

BUSINESS	2028
($ Millions)	$
Transmission	196.86
Distribution	180.17
Other	65.56
Total	442.59
(% of Total)	%
Transmission	44%
Distribution	41%
Other	15%
Total	100%

Table 2 - Overhead Capitalization Rate for Tx and Dx Businesses

OVERHEAD CAPITALIZATION RATE	2028
Transmission Rate	7.00%
Distribution Rate	9.00%

Table 3 - Allocation of Shared Assets to Tx and Dx Businesses*

Type	Asset Value	Transmission	Distribution	Other	TX %	DX %	Other %
Major Assets							
Buildings and Fixtures	$ 332.26	$ 133.78	$ 198.01	$ 0.47	40.26%	59.60%	0.14%
Communication equipm	$ 28.22	$ 13.19	$ 14.87	$ 0.16	46.75%	52.68%	0.58%
Computer Equip Major	$ 32.91	$ 15.10	$ 17.34	$ 0.47	45.88%	52.68%	1.44%
Computer Software	$ 2.19	$ 0.99	$ 1.14	$ 0.06	45.36%	51.95%	2.69%
Intangibles Software	$ 348.59	$ 153.24	$ 184.23	$ 11.12	43.96%	52.85%	3.19%
Land	$ 22.58	$ 9.85	$ 12.74	$ -	43.60%	56.40%	0.00%
Leasehold improvemnt	$ (3.00)	$ (2.49)	$ (0.49)	$ (0.03)	82.78%	16.23%	0.99%
Syst supervisry equp	$ 23.90	$ 10.91	$ 12.83	$ 0.16	45.65%	53.70%	0.65%
Subtotal - Major Assets	$ 787.66	$ 334.58	$ 440.66	$ 12.42	42.48%	55.95%	1.58%
Minor Assets							
Transportation equip	$ 95.22	$ 31.79	$ 63.43	$ -	33.39%	66.61%	0.00%
Power operated equip	$ 112.04	$ 37.41	$ 74.64	$ -	33.39%	66.61%	0.00%
Aircraft & Railway	$ 37.87	$ 27.56	$ 10.31	$ -	72.77%	27.23%	0.00%
Comp Equip / Telecom	$ 39.68	$ 18.11	$ 20.55	$ 0.32	45.63%	51.79%	0.79%
Tools,shop,garag equ	$ 6.67	$ 3.76	$ 2.91	$ -	56.35%	43.65%	0.00%
Office furnitre Equp	$ 3.63	$ 1.70	$ 1.93	$ -	46.84%	53.16%	0.00%
Measurement & testin	$ 5.65	$ -	$ 5.65	$ -	0.00%	100.00%	0.00%
Misc. service equipm	$ 5.88	$ 3.32	$ 2.57	$ -	56.35%	43.65%	0.00%
Stores equipment	$ 0.27	$ 0.15	$ 0.12	$ -	55.31%	42.84%	0.00%
Subtotal - Minor Assets	$ 306.91	$ 123.78	$ 182.10	$ 0.32	40.33%	59.33%	0.10%
Cloud Computing Implementation Cost - In Service	$ 20.16	$ 10.81	$ 9.18	$ 0.04	53.64%	45.54%	0.21%
Total - All Shared Assets	$ 1,114.73	$ 469.17	$ 631.95	$ 12.77	42.09%	56.69%	1.15%

**Data as of December 31, 2025 ($M)*

2. Corporate Cost Allocation Framework

2.1 The Use of and Reliance on Shared Corporate Services and Assets

Large corporations use Shared Services as an effective, efficient strategy to provide support services to affiliated companies and business segments. The decision to provide Shared Services rather than deliver services within each affiliate separately depends on the balance between the costs and benefits of decentralized and centralized service provision. Centralized service provision benefits from economies of scale, efficient knowledge transfer, common systems and support, and management's ability to identify efficiencies and alignment across affiliates. Decentralized operations can result in higher costs and inconsistent standards, but may also provide the benefits of flexibility and recognition of specific requirements. For services whose benefits outweigh the costs, providing them centrally to multiple Affiliates is preferable. Services that require unique functions specific to a single affiliate, or that benefit from the flexibility to account for an affiliate's unique requirements, should remain decentralized. In the end, the balance between centralized and decentralized services is largely a matter of corporate organizational strategy and will not be the same for all entities. This is a similar question for Shared Assets, where decisions about when to share the use of assets across multiple affiliates and when to purchase assets solely to serve one affiliate will depend on the nature of the asset and the affiliate's specific requirements. Savings can be expected from economies of scale when investing in assets that serve multiple affiliates, even if those affiliates serve different markets (e.g., software infrastructure, office buildings).

Hydro One has developed an organizational structure to leverage the benefits of Shared Services and Shared Assets. There are still many functions and assets that remain decentralized, given that they directly serve one affiliate or the Tx or Dx businesses and benefit from the direct fulfillment of that affiliate's or the Tx or Dx business’s specific, unique requirements.

2.2 Hydro One’s Organizations

The Hydro One group of companies includes the wholly owned subsidiaries, partnerships, and business segments listed in **Table 4**. The OEB regulates the businesses identified in **Table 4** separately. Certain entities and business segments are rate-regulated, while others are not. For this reason, Hydro One must maintain clear cost attribution among regulated and non-regulated businesses, and among separately regulated Transmission and Distribution entities, for regulatory and financial reporting purposes.

Table 4 – Hydro One Affiliates and Businesses

SUBSIDIARY	BUSINESS SEGMENT	REGULATED	DESCRIPTION
Hydro One Ltd.	Holding	No	Public company that owns Hydro One Inc., Hydro One Telecom Inc., and other non-regulated businesses. Hydro One Ltd. is owned by public shareholders as well as the Province of Ontario.
Hydro One Inc.	Holding	No	Subsidiary of Hydro One Ltd. Acts as the holding company of Hydro One's rate-regulated businesses, including Hydro One Networks Inc.
Hydro One Networks Inc.	Distribution	Yes	Owns and operates a distribution system that spans approximately 75% of Ontario and serves over 1.3 million customers.
	Transmission	Yes	Owns and operates a very significant majority of Ontario's electricity transmission system
	Non-Regulated	No	Costs incurred by Hydro One Networks to support non-regulated business activities, which are excluded from recovery through regulated rates. The unregulated business provides opportunity for additional growth, including Acronym Solutions, Inc. and Aux Energy.
Acronym Solutions	Acronym	No	Subsidiary company of Hydro One Ltd. serving as a full-service Information and Communications Technology (ICT) provider to carriers, Internet service providers, and large public and private sector organizations.
Hydro One Remote Communities Inc.	Remotes	Yes	Subsidiary company of Hydro One Inc. that owns, operates, maintains, and constructs generation and distribution assets used to supply electricity to remote communities in northern Ontario.
Aux Energy	Aux	No	Subsidiary of Hydro One Inc. that offers services for fleet electrification, microgrids, and battery storage.
Hydro One Sault Ste. Marie Limited Partnership	HOSSM	Yes	Subsidiary company of Hydro One Inc. that connects Northern Ontario to Southern Ontario and next to Hydro One Networks Inc. is one of the largest electricity transmitters in the Province.
B2M Limited Partnership	B2M Transmission	Yes	B2M is a partnership between Hydro One and Saugeen Ojibway Nation (SON) that carries on the business of owning and operating a continuous transmission line between the Bruce Nuclear Power Development and Hydro One's Milton Switching Station.
Niagara Reinforcement Limited Partnership	NRLP Transmission	Yes	NRLP is a partnership between Hydro One, Six Nations of the Grand River Development Corporation (SNGR) and Mississaugas of the Credit First Nation (MCFN) that carries on the business of owning and operating a transmission circuit between the Allanburg Transmission Station near Niagara Falls and Hydro One's Middleport Transmission Station.

Chatham x Lakeshore Limited Partnership	CLLP	Yes	CLLP is a partnership between Hydro One Inc. and First Nation partners, established to develop major transmission infrastructure, modernize the grid, increase capacity, and foster partnerships with the Indigenous communities.

3. Guiding Principles of Cost Allocation

3.1 The Need for Cost Allocation

Cost allocation is required when costs are not tracked for each activity that relates to an individual recipient of services. For instance, a Shared Service employee in accounts payable could track time spent processing each invoice and the entity charged for that invoice, and this time sheet record could be used to allocate that employee's costs to each entity. However, this is not practical or desirable, given that invoices may relate to multiple entities and that time may be spent improving or ensuring the effectiveness of the invoice review process. Activity-based time tracking requires significant time for the employee to track their time. If this were always practical, then there would be no need for cost allocation principles or methods; costs would follow the time sheets for all employees. This, however, is not practical given the time and effort for employees to track their time and the fact that there will always be employees who work on processes or projects that simultaneously benefit multiple business entities (i.e., the accounts payable manager who trains employees and works with the information systems division to develop more streamlined processes).

3.2 Principles of Cost Allocation

The guiding principle for cost allocation is that cost responsibility should follow cost causation. As such, company policy and allocation methodology should satisfy the following criteria:

- The method should be based on cost causation. Cost causation means there is a causal relationship between the basis used to allocate a cost and the cost incurred. Costs are recognized as being caused by a service or group of services if (a) the costs are brought into existence as a direct result of providing the service or group of services; or (b) the costs are avoided if the service or group of services is not provided.
- If cost causation cannot be used or is determined to be inappropriate in the circumstances, the method usually considered next is benefits received (i.e., allocated to the business that received the benefits).
- The method should be based on data that can be obtained at a reasonable cost and are objectively verifiable, in the initial year as well as in subsequent years.
- When relying on estimates, results should be unbiased, reasonably consistent with comparable data, and provided by employees familiar with the costs.

3.3 Methods of Cost Allocation

There are two methods for allocating or distributing shared costs among a utility's businesses: Direct Assignment and Allocation.

Direct Assignment is used when it can be reasonably determined that all or a designated portion of an activity is performed for a particular business. Direct Assignment is completed through time studies or time surveys, in which participants either fill out time sheets during a sample period or indicate how they spend their time throughout the year.

Allocation is used when more than one business uses an activity. Still, the portions of the activity that each uses cannot be directly established through a time study or time survey. In this case, a cost driver must be assigned to allocate the activity's costs. A cost driver is a formula for allocating the cost of an activity among the entities that cause it to be incurred.

3.4 Cost Drivers

As stated above, a cost driver is a formula for sharing the cost of an activity among the entities that cause it to be incurred. The guiding principle that Atrium applied in evaluating and recommending cost drivers is cost causation and, in cases when cost causation cannot be easily established, cost drivers are assigned based on a review of the level of benefits received (e.g., diversity and inclusion activities may not be caused by a particular affiliate or group of businesses but the benefits of the programs can accrue to the affiliates and businesses who participate in the strategies, plans, programs and policies).

Other factors considered in assigning cost drivers include:

- **Practicality –** The cost driver should be understandable, obtainable at a reasonable cost, and objectively verifiable in the initial year as well as in subsequent years.
- **Stability –** Cost driver values should be reasonably stable from year to year. When estimates are used, the cost driver should be estimable with reasonable accuracy, and the estimates should be unbiased.
- **Materiality –** When choosing between cost drivers, small differences can often be ignored in favor of the above-listed factors, Practicality and Stability.

3.5 Types of Cost Drivers

Cost drivers can be classified as External or Internal. External drivers are based on data that are external to the cost allocation process, such as physical units or financial amounts. Internal drivers are based on values computed as an integral part of the cost allocation process. For example, the cost of a supervisor's salary might be allocated in the same proportion as the

salaries of the people being supervised, and the cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities.

Table 5 – Types of Cost Drivers

TYPE	DESCRIPTION	EXAMPLES
External Cost Drivers		
Physical	Physical units; usually objectively determinate but often require estimates	Headcount (of employees), Kilometers of Lines
Financial	Financial information from accounting or management reports, budgets, or projections	Capital expenditures, Net utility plant, Program Project Costs, Total capital, Total revenue
Blended or Multi-Factor	Weighted combinations of other drivers are used when one or more drives are applicable, and none is clearly preferable.	Equal weighting of Capital, Labour, Revenue
Internal Cost Drivers		
All Internal Cost Drivers	Use the result of previous allocations as the basis for further allocations.	The cost of general departmental expenses might be allocated in the same proportion as the specifically assigned departmental activities.

3.6 Blended or Multi-Factor Allocation

The use of multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified is a widely respected and common practice across the utility industry. The most common multi-factor allocation is a three-factor formula, with each factor equally weighted (generally referred to as the Massachusetts Formula), where the three components of the factor are representative of: (1) Capital, (2) Revenue, and (3) Labour. The implementation of the Massachusetts Formula varies slightly as entities use different measures to represent the three components (e.g., net plant/rate base, revenue/margin, labour/headcount).

Often, the multi-factor allocator is chosen to account for the idea that a business's size and scope affect the level of services it receives from certain common corporate services. The corporate services that are impacted by the size and scope of the business typically include executive costs, the board of directors, corporate affairs, the CFO/controller, legal/general counsel, and strategy and innovation. These are high-level costs related to the business's oversight and strategy. The inability to find a single direct assignment that is most appropriate leads to the use of a multi-factor allocation that reasonably represents the size and scope of the business, which impacts the time and effort spent or the service received from these common corporate services. In short, it is more common to see multi-factor allocations as the requirement for an allocation shifts from direct operations up the organization to high-level support and strategy, where multiple factors relate to the time and effort spent and the benefits received.

For Hydro One's Corporate & Shared Cost Allocation Methodology, the three-factor allocation driver based on Capital, Labour, and Revenue was utilized as appropriate to reflect the fact that the effort associated with a certain activity relates to the overall size, scale, and importance of each operating entity rather than to any single operating entity or by any particular allocation factor.

4. Allocation of Common Corporate Costs

4.1 Purpose of Allocating Common Corporate Costs

Hydro One's organizational structure takes advantage of the benefits of Shared Services; as a result, it is necessary to allocate the costs of these Shared Services among Hydro One, its affiliate companies, and between the Tx and Dx businesses. While this allocation is in place to avoid cross-subsidization and comply with the relevant provisions of the Affiliate Relationships Code, it also allows Hydro One leadership to evaluate all costs incurred by each affiliate.

4.2 Shared Services

Hydro One provides Shared Services through the Lines of Business identified in **Table 6**, to the affiliates and businesses identified in **Table 4. Appendix A** further describes the Lines of Business listed below.

Table 6 – Lines of Business Providing Shared Services

COST GROUPING	LINE OF BUSINESS
Corporate	Board of Directors Ombudsman President/CEO Office
Corporate Affairs	Corporate Sustainability EVP Corporate Affairs Indigenous Relations Marketing & Communications Stakeholder Relations
Finance	Audit Chief Financial & Regulatory Officer Corporate Ethics Corporate Secretary Facilities & Real Estate Finance Business Services Finance Enablement Financial Reporting Internal Controls & Compliance Investor Relations Legal Pension Regulatory Affairs Regulatory Finance Risk SVP Finance Tax Treasury VP – FP&A
Human Resources	Employee & LR, Diversity & Governance EVP HR People Strategies & HR Initiatives Rewards & Human Capital Mgmt Transformation Management Office LTD
DTS	DTS Digital & Technology Solutions
Safety, Operations, and CE	Customer Service and Billing Ops EVP Safety, Ops & Customer Experience Integration, Reliability, and Emergency Mgmt System Control
Strategy and ET	Corporate Development Customer Relations Strategy EVP, Strategy, Energy, Transition Planning Strategy and Innovation Tx System Planning & Large Customer

The Lines of Business in **Table 6** organize themselves into Cost Centers, which may represent a single activity or multiple activities. For instance, the Audit Line of Business contains two Cost Centers, one of which supports financial control assurance and the other provides four services relating to (1) financial statement reporting support, (2) IT/OT Governance & Cybersecurity audits, (3) Safety, Ops, Customer Experience audit support, and (4) Capital Project Delivery audit support.

4.3 Cost Allocation Methodology

The allocation methodology for Hydro One's Common Corporate Costs was designed to address the following considerations:

- Compliance with relevant provisions of the Affiliate Relationships Code
- Cost incurrence- Are the costs needed to perform services required by the business?
- Cost allocation- Are costs appropriately allocated among businesses, based on the application of cost drivers /allocation factors supported by principles of causality?
- Cost/benefit- Do benefits received equal or exceed the cost?

An overview of the methodology is described below:

- Through interviews with Hydro One personnel, identify the Shared Services included in Common Corporate Costs and the particular activities performed to provide these Shared Services.
- Through interviews with Hydro One personnel, time surveys, and analyses of time spent by employees, distribute the costs of each Shared Service among the activities performed by that Line of Business to provide that Shared Service.
- Distribute the cost of each activity among Hydro One, its affiliate companies, and between the Tx and Dx businesses based on direct assignment (see Section 3.3) or on cost drivers (see Section 3.4) when direct assignment is not possible.

Further, in instances when Common Corporate Costs can be directly attributed to expenditures for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers. These costs are not included in Hydro One's Corporate & Shared Cost Allocation Methodology because they are recorded and transferred before determining the total Common Corporate Costs to be allocated.

The Corporate & Shared Cost Allocation Methodology is based on the current methodology used in Hydro One's Business Plan. The Corporate & Shared Cost Allocation Methodology is based on the current methodology used in Hydro One's Business Plan. Atrium reviewed the methodology to assess whether it remains appropriate and to identify changes warranted by Hydro One's current circumstances.

Based on our discussions with Hydro One personnel and detailed review of the past methods employed, Atrium determined that the Corporate & Shared Cost Allocation Methodology continues to be appropriate for Hydro One because:

- It meets best generally accepted regulatory practices for cost allocation since it distributes costs based on cost causation, including the use of direct assignment when possible, and then through the use of cost drivers.
- The OEB has accepted it.
- It has the support of Hydro One management and is understood and accepted by Hydro One, its affiliate companies, and the Tx and Dx businesses.
- It allows Hydro One, its affiliate companies, and the Tx and Dx businesses to determine precisely what amounts they are charged by department and by activity within the department, and this transparency provides a basis for understanding the nature of the charges and value of the services received.
- It is well-integrated with Hydro One's annual business planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization, and it can be adapted easily to reflect those changes.

4.4 Refinements Identified Through the Current Review

While Atrium concluded that the general methodology remains appropriate, the current review identified several refinements to better reflect Hydro One's organization, operations, available data, and planning period.

4.4.1 Development of Allocation Factors for Each Plan Period

As part of its review, Atrium observed that the relative relationships among affiliates are expected o change over the 2028–2032 planning period, particularly as Hydro One's joint venture portfolio evolves (see further discussion in Section 4.4.3 below). To better reflect these changes, Atrium recommended that Hydro One develop a unique set of allocation factors for each year of the plan period . These factors are designed to align with the underlying cost drivers for that specific period, ensuring that cost allocations remain representative of resource utilization. Where appropriate, allocation factors may also be based on a multi-year average, as discussed below, to smooth short-term fluctuations and provide a more stable, representative basis for cost allocation. This approach supports greater accuracy, consistency, and transparency in allocating shared costs across affiliates throughout the plan period.

4.4.2 3-Year Average Program and Project Costs Allocation Driver

Based on Hydro One's explanation that certain planning and support activities span multiple planning years, Atrium recommended use of a three-year average of Program and Project Costs

(Program Costs, OM&A, and Project Costs Capital) for those activities rather than a single-year measure. The three-year average better reflects the multi-year nature of planning, capital development, and associated support activities and reduces volatility associated with a single-year measure. Previously, the methodology used Program and Project costs based on a single plan period. The three-year average was developed on a rolling-forward basis, which better reflects the multi-year nature of planning, capital development, and associated support activities and reduces volatility from single-year measures.

4.4.3 Allocation to Transmission Affiliates

In prior reviews, common corporate costs associated with Hydro One's Transmission affiliates and partnership entities, including B2M, NRLP, and CLLP, were allocated to the applicable individual entities based on the methodology then in effect. These entities generally rely on Hydro One Networks Inc. for corporate and shared services support under applicable service arrangements, rather than maintaining separate internal staffing for those functions.

As part of the current review, Hydro One identified concerns regarding whether the methodology should continue to treat each existing and future joint venture entity separately at the initial allocation stage. Atrium evaluated the alternative portfolio approach in light of the shared nature of the services provided, the limited staffing within the entities, expected growth in the number of joint ventures, and the information available to support the allocation. Based on that review, Atrium concluded that allocating common corporate costs first to a joint venture portfolio provides a more stable and representative measure of the corporate support required for this group of entities.

After costs are allocated to the joint venture portfolio, Hydro One allocates those costs among the individual joint venture entities based on entity-specific allocation factors. Existing joint venture entities remain separately identified for cost attribution and regulatory purposes. Future joint venture entities are incorporated into the joint venture portfolio as they are established, and Hydro One then allocates the applicable portfolio costs among the individual entities, including the new entity, using the relevant allocation factors.

As these existing joint ventures are expected to change and evolve over the plan period (2028 – 2032), it was determined that treating them as a single portfolio of projects/companies would better capture costs than treating them individually. Additionally, as Hydro One is anticipated to establish additional or "future" joint venture companies during the JRAP plan period, it is important to properly allocate these costs as part of the Corporate & Shared Cost Methodology. Similar to the existing joint venture affiliates, the future joint ventures are treated as a single portfolio of projects/companies for cost allocation. This determination was based on Atrium's review of Hydro One's organizational structure, the nature of the shared

services provided to the joint venture entities, Hydro One management's expectations regarding future joint venture activity, and the availability of data to support a stable and transparent allocation methodology.

Building on this portfolio-based approach, Hydro One has updated the treatment of common corporate costs and shared asset allocations for both existing and future joint ventures. Approximately $2.6 million in common corporate costs is first allocated to the joint venture portfolio and then distributed across the four existing joint ventures in proportions broadly consistent with current practice, thereby limiting disruption to approved rates. At the same time, Hydro One is currently in the process of refining the allocation methodology for future major shared assets (particularly intangible software) to rely more on labour-based factors and common corporate effort rather than a generic three-factor (capital/labour/revenue) allocator, improving alignment between costs and the underlying drivers of service provision for both existing and future joint ventures.

4.4.4 IT Third-Party Contracts

For the current plan period, Hydro One has included certain third-party IT contract costs within the common work program budgets. From a regulatory perspective, the OEB's Affiliate Relationships Code ("ARC") explicitly includes information technology services within the scope of shared corporate services. Software, software-as-a-service ("SaaS") subscriptions, cloud-based systems, and enterprise platforms fall within this definition, where the associated services support common business functions and are allocated using a reasonable and consistently applied methodology.

Historically, internal IT sustainment activities supporting capital planning, engineering, and project execution activities have been included within Hydro One's overhead capitalization framework. As Hydro One's operations and project execution activities have become increasingly dependent on integrated digital systems, cloud computing environments, enterprise software, cybersecurity platforms, and digital work management tools, certain third-party IT contract costs now also support capital-related activities, similar to internal IT sustainment functions.

The key principle supporting this treatment is functional necessity and cost causation. Capital planning, engineering design, project management, scheduling, financial controls, and project execution activities increasingly rely on enterprise IT platforms and software environments to support the development and placement of capital assets into service. Accordingly, Atrium determined that certain third-party IT contract costs have a sufficiently direct relationship to capital-related activities to warrant inclusion within the overhead capitalization framework, provided the costs:

- support capital-related activities;
- are allocated using a reasonable and consistently applied methodology; and
- do not result in cross-subsidization.

This treatment applies only to IT services and platforms that functionally support capital-related activities. General-purpose IT costs and other enterprise technology costs that do not directly support capital-related activities remain classified as OM&A and are excluded from overhead capitalization.

For Hydro One, the methodology used to allocate applicable IT sustainment costs and relevant third-party IT contract costs to overhead capitalization is based on a cost-causative approach, including a combination of direct labour and shared services labour ("Total Labour including CC Labour"), allowing for a reasonable allocation of costs among Hydro One, its affiliates, and the Tx and Dx businesses.

To avoid duplication, costs that are directly charged to specific capital projects are excluded from the overhead capitalization calculation. Accordingly, the methodology does not permit double recovery of the same costs through both direct capital charges and overhead allocations.

Table 7 summarizes the allocation methods and cost drivers used to distribute the Common Corporate Costs among Hydro One, its affiliates, and the Tx and Dx businesses.

Table 7- Summary of Common Corporate Cost Allocation Methods

Cost Allocation Method	2028
(1) Direct Assignment - Time Survey	38.98%
Total Labour incl CC Labour	19.81%
Capital, Labour, Revenue	10.77%
Headcount	8.86%
(2) Total Cost Center Labour (for Non-Labour)	7.42%
Program & Project Costs	5.22%
Assets	3.05%
(3) Direct Non-Labour Assignment	2.44%
Program & Project Costs - 3 Yr. Average	1.32%
Project Costs Capital - 3 Yr. Average	1.19%
Project Costs Capital	0.54%
Other Allocators <0.5% for each	0.40%
Total	**100%**

Cost Allocation Method	2028
(1) Direct Assignment - Time Survey	38.58%
Total Labour incl CC Labour	20.58%
Capital, Labour, Revenue	10.63%
Headcount	8.93%
(2) Total Cost Center Labour (for Non-Labour)	7.32%
Program & Project Costs	5.15%
Assets	3.01%
(3) Direct Non-Labour Assignment	2.41%
Program & Project Costs - 3 Yr. Average	1.30%
Project Costs Capital - 3 Yr. Average	1.17%
Project Costs Capital	0.53%
OTher Allocators <0.5% for each	0.40%
Total	100%

These percentages align with previous reviews regarding the percentage of total costs allocated based on direct costs (time survey). In the current analyses the direct assigned costs are also approximately 48%, which is the sum of the rows (1) Direct Assignment – Time Survey (2) Internal – Total Cost Center Labour (for Non-Labour) and (3) Direct Non-Labour Assignment. Cost Drivers are further discussed in sections 3.5 and 3.6 above.

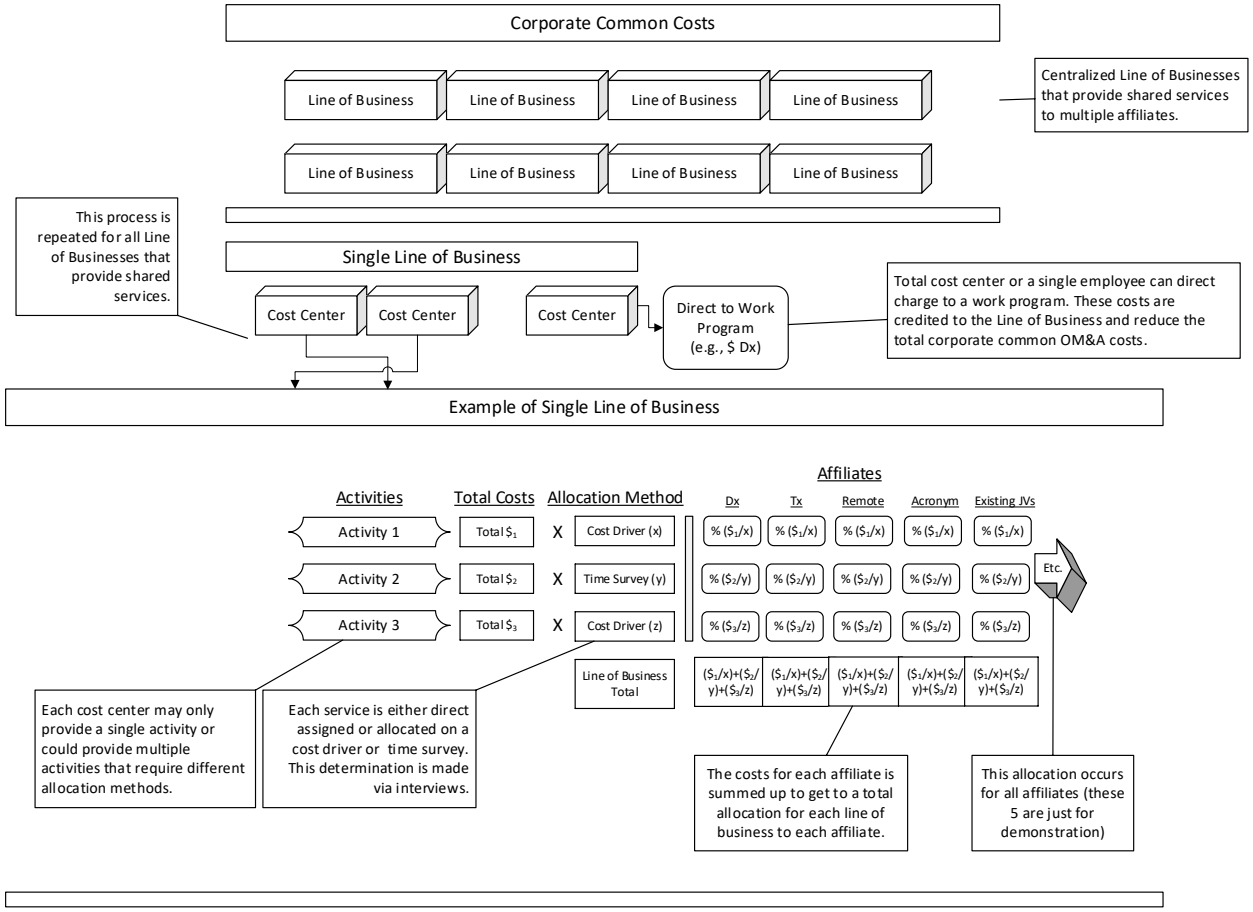
4.5 Review Process Employed by Atrium Economics

The general process employed to conduct the review was to evaluate the Lines of Business that provide shared corporate services, identify the activities performed, evaluate the allocation approaches for those activities, and assess the allocation factors or time surveys used to distribute costs among Hydro One, its affiliates, and the Tx and Dx businesses. This method is depicted in **Figure 1** below.

Consistent with this approach, Atrium reviewed Hydro One's organizational structure to identify the relevant Lines of Business and map shared services to cost centers. Based on budget data, management interviews, and other information provided by Hydro One, Atrium documented and evaluated the activities performed within each Line of Business and the costs associated with those activities. Atrium evaluated whether each activity supports OM&A, capital, or both, and assessed the allocation methodology applicable to each activity based on cost causation, data availability, and industry practice. Atrium also evaluated the affiliates and business units receiving or driving each activity and the treatment of associated non-labour costs. For the System Control function, Hydro One is currently undertaking an internal initiative to quantify

the allocation of work activities across the Hydro One organization and affiliates; pending completion of that effort, Hydro One applied the existing allocation methodology for this group.

Figure 1 – Common Corporate Cost Allocation Methodology



4.6 Conclusions and Results

With the inclusion of the enhancements described above, Atrium believes that Hydro One's current Common Corporate Cost allocation methodology is appropriate for Hydro One because it achieves the purposes for which it was designed: to distribute costs in a manner that is consistent with OEB precedent and regulatory practice for cost allocation, ensures legislative compliance (i.e., Hydro One Accountability Act), and promotes transparency and efficiency.

Table 8 presents the results of Hydro One's distribution of the Common Corporate Costs in the Business Plan year 2028, among its Transmission, Distribution, and Other businesses.

Table 8 - Distribution of Annual Common Corporate Costs for Ratepayer Recovery

Business	2028
($ Millions)	$
Transmission	196.86
Distribution	180.17
Other	65.56
Total	442.59
(% of Total)	%
Transmission	44%
Distribution	41%
Other	15%
Total	100%

The Common Corporate Costs Allocation Methodology yields a similar outcome to past methods with respect to the percentage of Common Corporate Costs allocated to the Transmission business, the Distribution business, and Hydro One and its affiliates (the Other category). There was an approximate 5% shift from Distribution businesses to Transmission and Other Businesses between the affiliate allocation method results and the results filed in EB-2021-0110, with percentages of 43% Transmission, 46% Distribution, and 11% Other.

There are two primary reasons why this movement is reasonable (1) the results of the previous 2020 review for 2023 is not directly comparable to the results of the current allocations applied to 2028 since the base period is not the same and the budget is not the same, and (2) changes in organizational structure and focus are to be expected as Hydro One evolves and adapts to new circumstances. For instance, as the portfolio of projects/companies across the Existing and Future Joint Ventures is expected to grow, the associated split of time and cost allocation across these areas of the business is expected to increase. Thus, the Common Corporate Costs Allocation Methodology reflects these changes in organizational focus in its inputs, affecting the allocation of costs to Hydro One, its affiliates, and the Tx and Dx businesses. In addition, Atrium reviewed the changes in each of the Line of Business with the Hydro One team assigned to this project, which also included members from Finance and Regulatory Affairs, and the changes occurring as a result of this review and their update aligned with their expectations, given the changes in the focus and organizational structure of Hydro One.

5. Overhead Capitalization Rate Methodology

5.1 Purpose of Overhead Capitalization Rate

Overhead Capitalization Rates are percentages applied to the cost of Transmission and Distribution capital expenditures, resulting in a portion of Common Corporate Costs being included in each business's capital expenditures. The Overhead Capitalization Rate is used to recover Common Corporate Costs that are not directly recorded to capital expenditures due to the nature of the costs; either employees who support capital expenditures but do not directly charge time to a specific capital project (assigned for less than three months or work on multiple projects simultaneously), or employees who perform work that impacts both capital and OM&A projects. For instance, time spent on risk evaluation and mitigation simultaneously impacts both capital and OM&A projects; without efficient and effective risk evaluation and mitigation, Hydro One would be unable to undertake OM&A and capital expenditures as effectively. In summary, the Overhead Capitalization Rate allocates to capital both (1) costs for Shared Service activities that directly support capital expenditures but are not billed directly to capital; and (2) costs for a portion of Shared Service activities that relate to both capital and OM&A simultaneously.

5.2 Application of Cost Allocation Principles to Overhead Capitalization Rate Methodology

In addition to alignment with the general principles of cost allocation discussed in **Section 3** - Guiding Principles of Cost Allocation, the methodologies for overhead capitalization should address a set of formal, objective criteria that align with company and policy objectives. Guiding regulatory principles for the Capitalized Common Corporate Costs allocation methodology include:

- **Defensible Cost Causation:** To conform to regulatory principles, the methodology should show a causal link between capitalized overhead and capital activity.
- **Distinguishable from Directly Allocated Capital Costs:** The overhead costs must be distinguished from those that are directly charged to capital (i.e., no duplication of costs and distinct sets of costs that are to be included in overhead).
- **Transparency:** The methodology and calculations should be easy to follow and understand by internal users and external reviewers.
- **Freedom from Bias:** The methodology should not contain a bias in the allocation of costs toward either operating or capital activities.
- **Stability:** The methodology should remain stable from year to year and not result in disproportionately large variations in the amounts of capitalized overhead from year to year.

- **Accuracy of Underlying Data:** Any data used in the methodology should be accurate and able to be relied upon for the purposes intended (i.e., provide an appropriate measure and reasonable approximation of the underlying volume of activity or output).
- **Flexibility/Adaptability:** The methodology should accommodate changes in organizational structure, availability of data, business processes, and information systems with reasonable ease.
- **Cost-effectiveness:** Methodologies should be cost-effective to implement. Additional accuracy may entail high additional cost, so an appropriate balance is needed between precision and cost, with respect to both implementation and ongoing costs.

5.3 Overview of Methodology

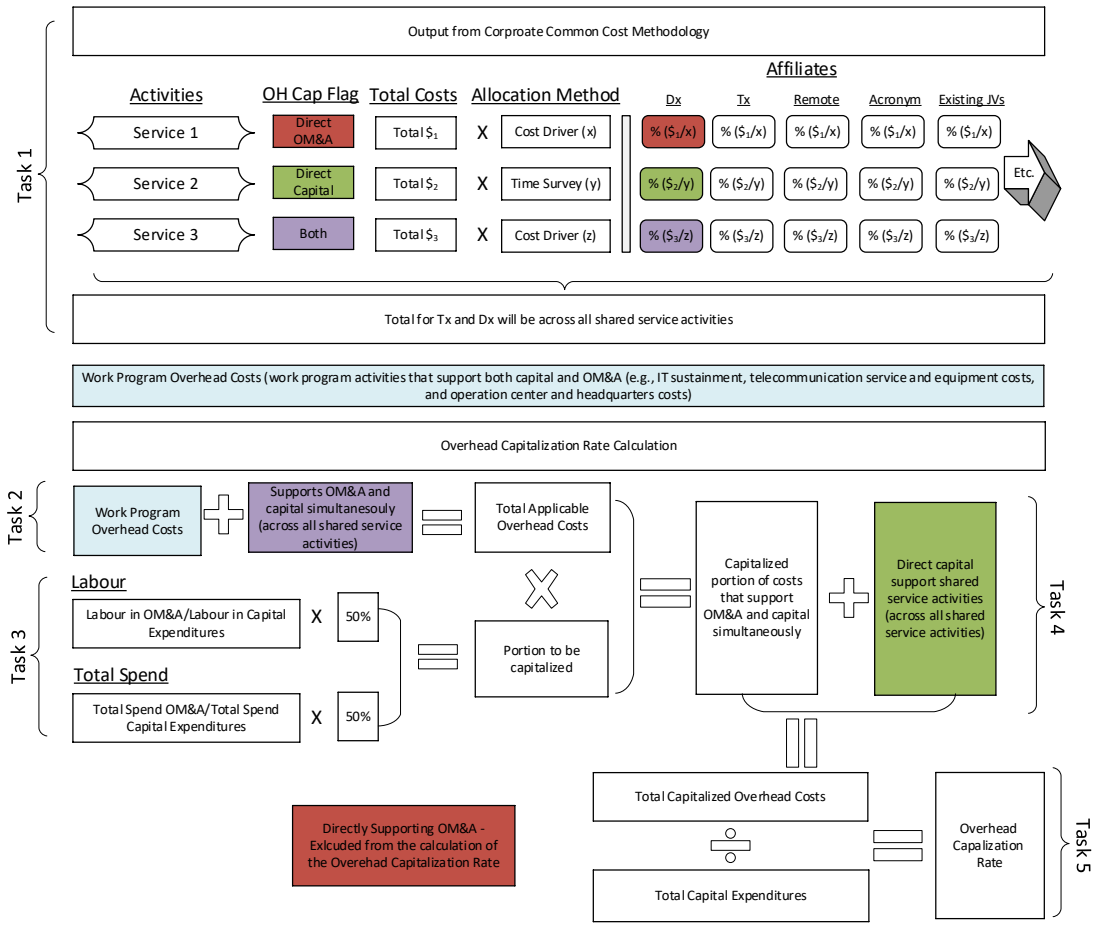
The purpose of this portion of the review is to evaluate whether the Overhead Capitalization Rate methodology remains appropriate and identify any refinements warranted by the current circumstances. The result of this methodology is two Overhead Capitalization Rates, one for Tx and one for Dx, which are applied to capital expenditures to recover a portion of common corporate costs that support capital activities. This process is depicted in **Figure 2** below.

Consistent with this approach, Atrium reviewed the classification of shared service activities to confirm whether each activity supports OM&A, capital, or both, as established in the common corporate cost allocation process. Atrium then evaluated the identification of total applicable overhead costs, including both Line of Business activities and relevant work programs, to ensure all appropriate costs that support both OM&A and capital were captured. Atrium reviewed the methodology used to split these costs between OM&A and capital, including the application of the labour and total spending capital ratios, to assess whether the approach remains reasonable, consistently applied, and aligned with cost causation principles. Hydro One is responsible for calculating the Overhead Capitalization Rates and applying them to Tx and Dx capital expenditures. Because these ratios use expenditure levels as proxies for the relative support of capital and OM&A activities, changes in expenditure levels should be evaluated to determine whether they reflect changes in underlying activity or merely changes in the cost of delivering that activity.

Plan-to-actual variances in capital expenditures should be evaluated to determine whether they reflect productivity improvements, timing differences, changes in project scope, structural business changes, or other factors. In particular, a reduction in capital expenditures resulting from productivity improvements does not necessarily indicate a corresponding reduction in the level of shared-service support required to deliver the capital program. Where Hydro One achieves substantially the same capital program or level of activity at a lower direct cost as a result of identifiable productivity savings, those savings should be considered when assessing the capital activity measures and ratios used in the Overhead Capitalization Rate methodology. This avoids a mechanical shift of otherwise capital-related shared corporate costs to OM&A

solely because productivity has reduced the direct cost of the capital program. Any such adjustment should be supported by identifiable productivity savings, applied consistently, and avoid double counting or capitalization of costs that do not support capital activities.

Figure 2 - Overhead Capitalization Rate Methodology



5.4 Conclusions and Results

Below are the resulting Overhead Capitalization Rates for the 2028 Business Plan for both the Tx and Dx businesses.

Table 9 – Overhead Capitalization Rate for Tx and Dx Businesses

OVERHEAD CAPITALIZATION RATE	2028
Transmission Rate	7.00%
Distribution Rate	9.00%

The total Common Corporate Costs being recovered through the Overhead Capitalization Rate are consistent with the results in the previous review (EB-2021-0110) of 8.0% for the Transmission business and 9% for the Distribution business, compared to **Table 9** above of 7% for Tx and 9% for Dx, respectively.

6. Allocation of Shared Assets

6.1 Purpose of Allocating Shared Assets

In addition to allocating Common Corporate Costs, it is necessary to allocate the use of and costs for Shared Assets among Hydro One and its affiliate companies, and between the Tx and Dx businesses, to comply with the relevant provisions of the Affiliate Relationships Code. Atrium's objective in reviewing the method of allocating Shared Assets was to assess whether the allocations are reasonable, reflect regulatory principles, avoid cross-subsidization between businesses, and are consistent with the allocation of Common Corporate Costs.

Atrium then evaluated the allocation methodologies and cost drivers reflected in Hydro One's Shared Asset information to assess their consistency with cost causation principles, industry practice, and available information, and recommended refinements where warranted. Hydro One provided Atrium with a list of all Shared Assets, summarized by asset group and subgroup, as shown in **Figure 3** below.

Figure 3 – Types of Shared Assets

ASSET GROUP	ASSET SUBGROUPS
Major Assets	■ Software • Intangibles Software • Computer Equipment • Computer Software ■ Buildings and Telecommunication Equipment • Land • Buildings and Fixtures • Leasehold Improvements • Communication Equipment • System Supervisory Equipment

Minor Assets	■ Aircraft ■ Transportation & Work Equipment ■ Computer Hardware ■ Office Equipment ■ Measurement and Testing ■ Service Equipment- Miscellaneous ■ Service Equipment- Storage ■ Tools
Prepaid Cloud	■ Cloud Computing Implementation Cost – In Serviced Projects

6.2 Overview of Methodology

The Transmission and Distribution businesses directly purchase most fixed assets. In contrast, the remaining assets, classified as shared assets, are held by Hydro One Networks Inc. and allocated across Hydro One, its affiliates, and the Tx and Dx businesses. The portion of shared asset costs not allocated to Tx or Dx is used to develop transfer prices charged to affiliates, with resulting revenues applied as an offset to the revenue requirements of the Tx and Dx businesses.

The general process employed in this review was to develop an understanding of the nature and use of shared assets and to evaluate the methodologies used to allocate those assets among Hydro One, its affiliates, and the Tx and Dx businesses. Consistent with this approach, Atrium reviewed the composition of shared asset groups and subgroups to understand how assets support shared services and specific businesses, based on documentation and management interviews. Atrium then evaluated and selected allocation methodologies and cost drivers for each asset group, applying cost causation principles, industry practice, and data availability.

Major Assets

- **Software -** Most of the software included in Shared Assets is related to Hydro One's common computing infrastructure, which is comprised of various enterprise software systems necessary to support Hydro One's operations, including work management, asset management, engineering, financial, human resources, cybersecurity, and other enterprise functions. While Hydro One's SAP ("Cornerstone") system historically represented a significant component of the Software asset group, it is now substantially amortized and represents a smaller share of the overall software allocation. The cost of software assets is allocated using cost drivers that reflect the activities and functions supported. For example, software implementation costs related to Human Resources

are allocated based on headcount, while certain systems may be directly assigned to a particular business where the software supports a specific function (e.g., the customer information system assigned to the Dx business).

- **Buildings and Telecommunications Equipment -** Each asset included in Buildings and Telecommunications Shared Assets was allocated using one of the following methods:
- **Specific estimation for a building -** For example, the Sudbury Service Centre and Barrie Area Buildings have estimated usage of Transmission-20% and Distribution-80%.
- **Direct assignment based on type of usage -** For example, Hydro One summarized Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2020-2025 and determined that Fleet usage was Transmission- 33% and Distribution-67%; therefore, the costs for buildings used for Fleet were allocated using these percentages.
- **Cost Drivers -** For example, buildings used to manage both Distribution and Transmission projects are allocated using the cost driver OM&A and capital expenditures, developed as part of the Allocation of Common Corporate Costs methodology.

Minor Assets

Atrium reviewed the lists of individual items and determined that the following allocations are appropriate:

- **Aircraft –** Includes helicopter and supporting components. Usage was based on an analysis of time charges (recorded on time sheets concurrently with usage) for the years 2020 – 2025.
- **Transportation & Work Equipment** – Includes primary vehicles and associated equipment. Allocated using the cost driver "Fleet", which represents Fleet time charges (which are recorded to time sheets concurrently with usage) for years 2020-2025.
- **Computer Hardware –** Includes Laptops, Desktops, Network Equipment, Printers, etc. Allocated using the cost driver Headcount.
- **Office Equipment –** Includes office furniture and other office equipment. Allocated using the cost driver Headcount.
- **Measurement and Testing Equipment –** Includes testing and measurement equipment and tools used for Distribution. Directly assigned to Distribution.
- **Service Equipment-** Storage – Includes Waste Storage and Other Storage equipment. Allocated using the cost driver based on total OM&A expenditures and capital expenditures for Tx and Dx businesses.
- **Service Equipment -** Miscellaneous – Includes miscellaneous equipment. Allocated using the Total Common Corporate Costs cost driver, developed as part of the Common Corporate Cost allocation methodology.
- **Tools –** Includes Rental tools. Allocated Distribution-20% / Transmission-80% reflecting estimated usage based on information as to which business units are renting the tools.

Prepaid Cloud Computing Costs

- **Cloud Computing -** Prepaid Cloud Computing Implementation and Amortization Costs on In-service Projects. Allocated using the Program and Projects Costs driver, developed as part of the Common Corporate Cost allocation methodology.

Atrium reviewed the population of cost drivers used to allocate shared asset costs, including those aligned with the common corporate cost allocation, as well as additional drivers developed for specific asset groups such as aircraft, fleet, central maintenance services, and field offices. Atrium reviewed the application of these methodologies and the resulting allocation of Shared Asset costs across Hydro One, its affiliates, and the Tx and Dx businesses.

Finally, Atrium reviewed the development of transfer pricing for affiliates, whereby the portion of shared asset costs not allocated to Tx or Dx is used to calculate affiliate charge rates. These charges reflect affiliate use of shared assets and are applied as a reduction to the revenue requirements recovered through Transmission and Distribution rates, ensuring no cross-subsidization between regulated and affiliate businesses.

The transfer price charge rates represent Hydro One's affiliate businesses' use of the Shared Assets. The approach to developing the transfer price charge rates is as follows:

- The portion of each asset that should be allocated to Hydro One and each affiliate based on the appropriate cost driver was determined (result of Task 4 above).
- A revenue requirement was developed for the Shared Assets subgroup based on the components of the revenue requirement (return on debt, return on equity, taxes, and depreciation expense) for the Tx and Dx businesses for each Shared Asset subgroup.
- This revenue requirement for each Shared Assets subgroup was multiplied by the portion of the Shared Assets subgroup allocated to each affiliate with transfer pricing.
- These resulting dollar amounts were summed for each Shared Asset subgroup for each affiliate with transfer pricing to develop the total transfer price.

6.3 Refinements Identified Through the Current Review

The general methodology for allocating Shared Assets and developing the transfer pricing remains consistent with the methodology used in prior periods. As part of the current review, Atrium reviewed the Shared Assets and consulted with Hydro One personnel familiar with the nature of each asset to assess the appropriateness of the applicable allocation factor. Further, the methods employed to allocate Shared Assets align with those used to allocate Common Corporate Costs. When Shared Services and Shared Assets provide a similar service, the allocation factor is the same for both methodologies.

6.3.1 Prepaid Cloud Computing Costs

Hydro One has included Prepaid Cloud Computing Implementation and Amortization Costs on In-service Projects as part of the Shared Assets allocated to Hydro One, its affiliates, and the Tx and Dx businesses. While not considered fixed assets, these costs are subscription-based services that, under US GAAP, are treated as prepaid assets on the balance sheet, with the associated amortization expensed over the benefit period. For purposes of the allocation methodology, the relevant regulatory consideration is not the accounting classification alone, but whether the costs functionally support shared services and capital-related activities. In this instance, the included costs support shared services and capital-related activities, including capital planning, engineering design, project management, and project execution. Given the nature of the costs, the functions they support, and the available information regarding business usage, Atrium recommended the use of the Program and Project Costs driver to allocate these costs among Hydro One, its affiliates, and the Tx and Dx businesses.

6.4 Conclusions and Results

Atrium believes that Hydro One's current allocation of Shared Assets is appropriate for Hydro One because it aligns with the objectives for which it was designed: to fairly attribute and recover the Shared Assets from Hydro One, its affiliates, and the Tx and Dx businesses in a manner consistent with regulatory practice and the requirements of the Affiliate Relationships Code. Hydro One's other affiliated businesses are used to develop any applicable transfer pricing for those Affiliates.

Table 10 below provides the resulting allocation of Shared Asset values as of December 31, 2025, for the Transmission and Distribution businesses. In addition, this table includes a column labeled "Other," which represents allocations to Hydro One's other affiliated businesses and is used to develop any applicable transfer pricing for those affiliates.

Table 10- Allocation of Shared Asset Values ($Millions) (December 31, 2025)

Type	Asset Value	Transmission	Distribution	Other	TX %	DX %	Other %
Major Assets							
Buildings and Fixtures	$ 332.26	$ 133.78	$ 198.01	$ 0.47	40.26%	59.60%	0.14%
Communication equipm	$ 28.22	$ 13.19	$ 14.87	$ 0.16	46.75%	52.68%	0.58%
Computer Equip Major	$ 32.91	$ 15.10	$ 17.34	$ 0.47	45.88%	52.68%	1.44%
Computer Software	$ 2.19	$ 0.99	$ 1.14	$ 0.06	45.36%	51.95%	2.69%
Intangibles Software	$ 348.59	$ 153.24	$ 184.23	$ 11.12	43.96%	52.85%	3.19%
Land	$ 22.58	$ 9.85	$ 12.74	$ -	43.60%	56.40%	0.00%
Leasehold improvemnt	$ (3.00)	$ (2.49)	$ (0.49)	$ (0.03)	82.78%	16.23%	0.99%
Syst supervisry equp	$ 23.90	$ 10.91	$ 12.83	$ 0.16	45.65%	53.70%	0.65%
Subtotal - Major Assets	$ 787.66	$ 334.58	$ 440.66	$ 12.42	42.48%	55.95%	1.58%
Minor Assets							
Transportation equip	$ 95.22	$ 31.79	$ 63.43	$ -	33.39%	66.61%	0.00%
Power operated equip	$ 112.04	$ 37.41	$ 74.64	$ -	33.39%	66.61%	0.00%
Aircraft & Railway	$ 37.87	$ 27.56	$ 10.31	$ -	72.77%	27.23%	0.00%
Comp Equip / Telecom	$ 39.68	$ 18.11	$ 20.55	$ 0.32	45.63%	51.79%	0.79%
Tools,shop,garag equ	$ 6.67	$ 3.76	$ 2.91	$ -	56.35%	43.65%	0.00%
Office furnitre Equp	$ 3.63	$ 1.70	$ 1.93	$ -	46.84%	53.16%	0.00%
Measurement & testin	$ 5.65	$ -	$ 5.65	$ -	0.00%	100.00%	0.00%
Misc. service equipm	$ 5.88	$ 3.32	$ 2.57	$ -	56.35%	43.65%	0.00%
Stores equipment	$ 0.27	$ 0.15	$ 0.12	$ -	55.31%	42.84%	0.00%
Subtotal - Minor Assets	$ 306.91	$ 123.78	$ 182.10	$ 0.32	40.33%	59.33%	0.10%
Cloud Computing Implementation Cost In Service	$ 20.16	$ 10.81	$ 9.18	$ 0.04	53.64%	45.54%	0.21%
Total - All Shared Assets	**$ 1,114.73**	**$ 469.17**	**$ 631.95**	**$ 12.77**	**42.09%**	**56.69%**	**1.15%**

There are no material changes to the outcome of the Shared Asset allocations to the Transmission and Distribution businesses. The current analysis results in 42.09% to Tx and 56.69% to Dx, as shown in **Table 10**, compared to 38.39% to Tx and 60.6% to Dx filed in EB-2021-0110.

7. ECI-EPC Contracted Projects Overhead Capitalization Rate

7.1 Review of ECI-EPC Methodology

In addition to the review of Hydro One's general Corporate & Shared Cost Allocation Methodology described in this report, Hydro One maintains a previously established methodology for recovering overhead costs associated with Early Contractor Involvement ("ECI") and Engineering, Procurement, and Construction ("EPC") Contracted Projects ("ECI-EPC Contracted Projects").

As documented in Atrium Economics' 2023 report entitled Overhead Capitalization Methodology for ECI-EPC Contracted Projects, Hydro One established a distinct overhead capitalization approach for large transmission projects delivered under the ECI-EPC delivery model. See Appendix C for this report. The review concluded that these projects differ materially from Hydro One's standard transmission capital delivery model due to the significantly higher reliance on external contractors and the corresponding reduction in the level of internal Hydro One shared service support required per dollar of capital expenditure.

The 2023 review determined that a blended Overhead Capitalization Rate ("OCR") was appropriate for ECI-EPC Contracted Projects. Specifically, the methodology recognized that a substantial portion of project expenditures relate to externally provided OE/EPC services that do not utilize Hydro One's shared corporate functions to the same extent as internally managed capital activities. Accordingly, Atrium Economics recommended the application of a blended OCR comprised of:

- A reduced OCR applicable to the externally contracted portion of ECI-EPC project costs; and
- Hydro One's standard transmission OCR applied to the internally managed portion of project costs.

As part of the current review, Atrium considered whether changes in Hydro One's organizational structure, common corporate cost and overhead capitalization allocations, project cost forecasts, allocation factors, or 2028 Business Plan assumptions warranted modification of the previously established ECI-EPC methodology. Atrium also reviewed the application of the methodology using the current inputs described below.:

- Hydro One's current organizational structure;
- Updated common corporate cost and overhead capitalization allocations;
- Revised project cost forecasts and allocation factors; and

- The updated 2028 Business Plan assumptions.

Based on this review, Atrium Economics concludes that the use of a distinct blended OCR for ECI-EPC Contracted Projects continues to be reasonable and appropriate, as it reflects the differing level of support provided by Hydro One's shared corporate functions under the ECI-EPC delivery model relative to standard internally supported transmission capital projects.

Based on the updated inputs, Hydro One updated the calculation of the blended OCR for ECI-EPC Contracted Projects to be applied beginning in 2028, as presented below.

Table 1 - Overhead Capitalization Rate for ECI-EPC Projects

ECI-EPC Projects	2024	2025	2026	2027	2028	5 Year Avg	Rounded
Blended Overhead Rate	2.02%	1.95%	2.10%	2.26%	2.37%	**2.14%**	**2.0%**

Note: the blended overhead rate has been reviewed and updated as part of the annual integrated business planning process. As such, Table 1 reflects the most up-to-date rates.

Appendix A – Allocation of Common Corporate Costs by Line of Business

Line of Business	Description of Activities	Method of Allocation
Corporate		
Board of Directors	Provides governance oversight, Board and committee activities, and enterprise supervision.	Costs are allocated by entity using direct assignment (time survey) for specific entities and Capital, Labour, Revenue ("three-factor allocation") for remaining costs.
Ombudsman	Provides independent complaint resolution and reporting to support fair customer outcomes.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
President/CEO Office	Provides executive leadership, enterprise oversight, and coordination across Hydro One.	Costs are allocated by activity using the Board allocator for governance activities, three-factor allocation for enterprise support, direct assignment for shareholder-related activities, and Total Common Corporate Labour for non-labour.
Customer & Corporate Affairs		
Corporate Development	Supports mergers and acquisitions, growth initiatives, and corporate strategy execution.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Corporate Ethics	Provides ethics oversight, compliance support, and governance across entities.	Costs are allocated by entity using direct assignment (time survey) and three-factor allocation for labour, and Total Common Corporate Labour for non-labour.
Corporate Sustainability	Supports environmental, social, and governance (ESG) initiatives and sustainability reporting.	Costs are allocated by activity using three-factor allocation and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Customer Relations Strategy	Provides business planning, strategy, and customer program development.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Customer Service & Billing Operations	Supports billing, settlements, contract management, and customer service operations.	Costs are allocated by activity using direct assignment (time survey), three-factor allocation, and Project Costs Capital for labour and Total Common Corporate Labour for non-labour.
EVP Corporate Affairs	Provides executive leadership for corporate affairs, government relations, and stakeholder engagement.	Costs are allocated by activity using three-factor allocation and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.

Line of Business	Description of Activities	Method of Allocation
EVP Safety, Ops & Customer Experience	Provides oversight of operations, safety, and customer experience.	Costs are allocated by activity using Program & Project Costs for labour and Total Common Corporate Labour for non-labour.
Indigenous Relations	Supports Indigenous engagement, partnerships, and project coordination.	Costs are allocated by activity using Program & Project Costs and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Marketing & Communications	Provides communications, branding, and stakeholder engagement activities.	Costs are allocated by activity using three-factor allocation, Headcount, and direct assignment (time survey) for labour and applicable allocators for non-labour.
Stakeholder Relations	Supports government relations, policy development, and community engagement.	Costs are allocated by activity using three-factor allocation, Program & Project Costs, and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Finance		
Audit	Provides independent audit, financial controls assurance (including SOX), IT/OT governance, cybersecurity oversight, and audit support.	Costs are allocated by activity using three-factor allocation for core audit functions, Program & Project Costs for Safety, Ops & Customer Experience, Project Costs Capital for Capital Project Delivery, and Total Common Corporate Labour for certain non-labour costs.
Chief Financial & Regulatory Officer	Provides executive financial leadership and oversight of financial strategy and performance.	Costs are allocated by activity using three-factor allocation and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Facilities & Real Estate	Provides facilities management, land, and property support services.	Costs are allocated by activity using Project Costs Capital, three-factor allocation, and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Finance Business Services	Provides accounting, reporting, and transaction processing services.	Costs are allocated by activity using three-factor allocation, Project Costs Capital, and Headcount for labour and Total Common Corporate Labour for non-labour.
Finance Enablement	Provides financial systems, consolidation, and business analysis support.	Costs are allocated by activity using three-factor allocation and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.

Line of Business	Description of Activities	Method of Allocation
Financial Reporting	Provides internal and external financial reporting and accounting.	Costs are allocated by activity using three-factor allocation, Project Costs Capital, and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Internal Controls & Compliance	Provides internal control oversight and compliance support.	Costs are allocated by activity using Headcount for labour and Total Common Corporate Labour for non-labour.
Investor Relations	Manages investor communications and shareholder engagement.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Pension	Administers pension programs and defined contribution plans.	Costs are allocated by activity using Defined Contribution Headcount for both labour and non-labour.
Regulatory Finance	Supports regulatory financial analysis and filings.	Costs are allocated by activity using three-factor allocation for labour and Total Common Corporate Labour for non-labour.
Risk	Supports enterprise risk management and mitigation activities.	Costs are allocated by activity using three-factor allocation for labour and Total Common Corporate Labour for non-labour.
Strategic Finance	Provides financial planning, decision support, and strategic analysis.	Costs are allocated by activity using three-factor allocation, Project Costs Capital, and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Strategy & Innovation	Supports corporate strategy and innovation initiatives.	Costs are allocated by activity using three-factor allocation for both labour and non-labour.
SVP Finance	Provides executive financial leadership and oversight.	Costs are allocated by activity using three-factor allocation and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Tax	Provides tax compliance, planning, and advisory services.	Costs are allocated by activity using three-factor allocation and Headcount for labour and three-factor allocation for non-labour.
Treasury	Manages financing, insurance, and treasury operations.	Costs are allocated by activity using three-factor allocation for labour and Total Common Corporate Labour for non-labour.
VP-FP&A	Provides financial planning, forecasting, and analysis.	Costs are allocated by activity using three-factor allocation, Project Costs Capital, and direct assignment (time survey) for labour and Total

Line of Business	Description of Activities	Method of Allocation
		Common Corporate Labour for non-labour.
Human Resources		
Employee & LR, Diversity & Governance	Provides labour relations, diversity programs, and workforce governance.	Costs are allocated by activity using Headcount for labour and Total Common Corporate Labour for non-labour.
EVP HR	Provides executive leadership for human resources.	Costs are allocated by activity using Headcount for both labour and non-labour.
EVP Strategy, Energy Transition	Provides strategic leadership for energy transition initiatives.	Costs are allocated by activity using Headcount for both labour and non-labour.
LTD	Administers long-term disability programs.	Costs are allocated by activity using labour-based allocation for labour and Total Common Corporate Labour for non-labour.
People Strategies & HR Initiatives	Provides HR services including payroll, talent, and HR operations.	Costs are allocated by activity using Headcount for labour and Total Common Corporate Labour for non-labour.
Rewards & Human Capital Mgmt	Supports compensation, benefits, and workforce analytics.	Costs are allocated by activity using Headcount and Program & Project Costs for labour and Total Common Corporate Labour for non-labour.
Information Solutions Division		
DTS Digital & Technology Solutions	Provides enterprise IT, cybersecurity, data, and infrastructure services.	Costs are allocated by activity using three-factor allocation, asset-based allocators, and Headcount where applicable for labour and Total Common Corporate Labour for non-labour.
Legal & Secretariat		
Corporate Secretary	Provides governance, Board administration, and corporate secretariat functions.	Costs are allocated by activity using direct assignment (time survey) and three-factor allocation for labour and Total Common Corporate Labour for non-labour.
Legal	Provides legal advice and regulatory support across the enterprise.	Costs are allocated by activity using three-factor allocation, Board allocator, Program & Project Costs, and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Regulatory Affairs	Supports regulatory filings, compliance, and rate design.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour or direct assignment for non-labour.

Line of Business	Description of Activities	Method of Allocation
Operations		
Integration, Reliability & Emergency Mgmt	Supports emergency management and system reliability functions.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
Planning	Supports capital planning, investment strategy, and system planning.	Costs are allocated by activity using Project Costs Capital, Program & Project Costs, and direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.
System Control	Supports system operations, control, and reliability.	Costs are allocated by activity using direct assignment (time survey) and Program & Project Costs for labour and Total Common Corporate Labour for non-labour.
Transformation Mgmt Office	Supports enterprise transformation and shared services strategy.	Costs are allocated by activity using Program & Project Costs for labour and Total Common Corporate Labour for non-labour.
Tx System Planning & Large Customer	Supports transmission planning and large customer management.	Costs are allocated by activity using direct assignment (time survey) for labour and Total Common Corporate Labour for non-labour.

Appendix B – Provisions of the Affiliate Relationships Code Considered

Atrium Economics primarily focused its analysis on the following provisions of the *Affiliate Relationship Code for Electricity Distributors and Transmitters* when assessing compliance:

"**affiliate**", with respect to a corporation, has the same meaning as in the Business Corporations Act (Ontario);

"**direct costs**" means costs that can reasonably be identified with a specific unit of product or service or with a specific operation or cost centre;

"**fully-allocated cost**" means the sum of direct costs plus a proportional share of indirect costs;

"**indirect costs**" means costs that cannot be identified with a specific unit of product or service or with a specific operation or cost centre, and include but are not limited to overhead costs, administrative and general expenses, and taxes;

"**information services**" means computer systems, services, databases, and persons knowledgeable about the utility's information technology systems;

"**market price**" means the price reached in an open and unrestricted market between informed and prudent parties, acting at arm's length and under no compulsion to act;

"**shared corporate services**" means business functions that provide shared strategic management and policy support to the corporate group of which the utility is a member, relating to legal, regulatory, procurement services, building or real estate support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee, or public affairs;

2.3.3 Where a Market Exists

2.3.3.1 Where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall pay no more than the market price when acquiring that service, product, resource or use of asset from an affiliate.

2.3.3.6 Where a reasonably competitive market exists for a service, product, resource or use of asset, a utility shall charge no less than the greater of (i) the market price of the service, product, resource or use of asset and (ii) the utility's fully-allocated cost to provide service, product, resource or use of asset, when selling that service, product, resource or use of asset to an affiliate.

2.3.4 Where No Market Exists

2.3.4.1 Where it can be established that a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility acquires from an affiliate, the utility shall pay no more than the affiliate's fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost may include a return on the affiliate's invested capital. The return on invested capital shall be no higher than the utility's approved weighted average cost of capital.

2.3.4.2 Where a reasonably competitive market does not exist for a service, product, resource or use of asset that a utility sells to an affiliate, the utility shall charge no less than its fully-allocated cost to provide that service, product, resource or use of asset. The fully-allocated cost shall include a return on the utility's invested capital. The return on invested capital shall be no less than the utility's approved weighted average cost of capital.

2.3.4.3 Where a utility pays a cost-based price for a service, resource, product or use of asset that is obtained from an affiliate, the utility shall obtain from the affiliate, from time to time as required to keep the information current, a detailed breakdown of the affiliate's fully-allocated cost of providing the service, resource, product or use of asset.

2.3.5 Shared Corporate Services

2.3.5.1 For shared corporate services, fully-allocated cost-based pricing (as calculated in accordance with sections 2.3.4.1 and 2.3.4.2) may be applied between a utility and an affiliate in lieu of applying the transfer pricing provisions of section 2.3.3.1 or section 2.3.3.6, provided that the utility complies with section 2.3.4.3.

Appendix C – Atrium Economics ECI-EPC Report

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Hydro One Networks Inc.

Overhead Capitalization Methodology for ECI-EPC Contracted Projects

August 9, 2023

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1 Executive Summary

1.1 Introduction

Hydro One asked Atrium Economics, LLC ("Atrium") to provide guidance and advice on a methodology for appropriately recovering overhead capitalization ("OH Cap") costs for ECI-EPC Contracted Projects (as defined below) through the application of an Overhead Capitalization Rate ("OCR"). This report discusses the underlying theoretical, conceptual, and methodological procedures utilized by Hydro One in their current OH Cap methodology as approved by the Ontario Energy Board ("OEB") in Hydro One's Joint Transmission and Distribution Rate Application for 2023-2027 ("JRAP" or "2023-2027 Application")[1] and presents a recommended method of recovering OH Cap costs relating to ECI-EPC Contracted Projects, and discusses the implications of this approach.

1.2 Background

As of 2021, Hydro One is utilizing an Early Contractor Involvement ("ECI") delivery model for affiliate Transmission Line Projects[2] that engages the services of an external Owner's Engineer ("OE") and the services of Engineering, Procurement, and Construction ("EPC") contractor for each significant Transmission system expansion spanning multiple years ("ECI-EPC Contracted Projects" or "ECI-EPC Delivery Model"). These ECI-EPC Contracted Projects are contracted at a significantly earlier stage of development (typically at the budgetary estimate instead of the late detailed estimate or construction estimate stage); when compared to Hydro One's standard EPC delivery model ("Standard Delivery Model" or "Standard Hydro One Tx Projects") currently utilized for sustainment and natural growth of the Transmission System.[3] As such, under the ECI-EPC approach, the OE/EPC contractors perform many of the development functions that would be performed internally under the Standard Delivery Model. Hydro One uses the ECI-EPC Delivery Model for such projects instead of the Standard Delivery Model that supports delivering the primary transmission portfolio as these projects exceed Hydro One's current internal capacity built to support standard system requirements. Due to ECI, the ECI-

[1] EB-2021-0110
[2] "The OEB notes that the costs that are to be recorded in this account are for projects which are the subject of an Order in Council or direction from the Minister of Energy or a letter from the IESO." from Finding of Issue 1 on Page 7 of DECISION AND ORDER EB-2021-0169 issued October 7, 2021
[3] The Standard Delivery Model could also include instances where an EPC is not utilized.

EPC contractor will thoroughly understand the risks, costs, and challenges associated with the project, thus giving greater certainty to Hydro One on the overall schedule and cost.

Directed Transmission Line Projects that are expected to fall under the Affiliate Transmission Projects Regulatory Account established in EB-2021-0169 (the "ATP Account")[4], were not included in the JRAP and are anticipated to be performed under the ECI-EPC Delivery Model.

1.3 Principal Considerations & Conclusions

As explained in more detail in this report:

- Hydro One identified a need to review the appropriateness of its current method of recovering overhead costs from the ECI-EPC Contracted Projects.

- Hydro One retained Atrium to provide guidance and advice on reviewing the nature of shared services[5] provided by Hydro One for ECI-EPC Contracted Projects and provide a recommended methodology for appropriately recovering OH Cap costs for ECI-EPC Contracted Projects.

- Through the review, Atrium determined that the size and delivery model of Hydro One's ECI-EPC Contracted Projects warrants a refinement to the calculation of the OCR as the nature of the shared services provided by Hydro One are different than those provided under the Standard Delivery Model. As such, there are different implications on the common corporate costs incurred by Hydro One in support of these capital projects.

- Hydro One estimates that 79.5% of the costs associated with ECI-EPC Contracted Projects relate to external contractor payments, and 20.5% relate to internal Hydro One incurred costs.

- Through cost analyses, as detailed in Section 5 of this report, Atrium determined

[4] Various components of Station work with respect to the project may be executed using the ECI-EPC Delivery Model.
[5] Shared services means the centralized business operations that support multiple businesses, affiliated companies, or multiple parts of the same organization. Common corporate costs are costs incurred to provide shared services to Hydro One and its affiliate companies.

an appropriate OCR is 79.5% of the costs associated with external contractor payments, averaging 1.0% over five years.

- Atrium recommends applying the OCR rate that is currently applied to projects under the Standard Delivery Model to the 20.5% of project costs that relate to internal Hydro One incurred costs (i.e., not ECI-EPC costs).

- The resulting recommendation is for Hydro One to modify its current OH Cap recovery method for these ECI-EPC Contracted Projects such that the ECI-EPC Contracted Projects are subject to a blended OCR that reflects the appropriate burden placed on Hydro One's shared services.

- This blended rate is calculated using the OCR mentioned above (five-year average of 1.0%) weighted at 79.5% and the standard OCR, currently applied capital projects under the Standard Delivery Model, to capital weighted at 20.5%.

- Atrium recommends using a five-year average as it reflects these projects' long duration, and also recommends reviewing the five-year average annually. Refinements may be required for efficient and effective operational and accounting administration.

Atrium believes this recommended methodology for recovery of overhead costs associated with ECI-EPC Contracted Projects aligns with the criteria and methods currently employed by Hydro One to allocate costs incurred to provide shared services to Hydro One and its affiliate companies. Specifically, the ECI-EPC Contracted Projects overhead cost recovery methodology fairly attributes and recovers these costs from the ECI-EPC Contracted Projects, ensuring the prudent and fair cost allocation to Hydro One's ratepayers.

2 Guiding Principles of Cost Allocation

2.1 The Need for Cost Allocation

Activities require cost allocation when existing accounting methodologies do not include tracking costs for providing services to recipients. Tracking one's time is not always practical or preferred, as activity-based time tracking isn't always an efficient use of one's time and

resources. In instances where activity-based time tracking is not preferable, utilizing cost allocation principles and methods is beneficial. For example, cost allocation is preferable to activity-based time for employees working on processes or projects that benefit multiple business entities simultaneously.

2.2 Principles Of Cost Allocation

With cost responsibility following cost causation as the guiding principle, company policy and allocation methodology should satisfy the following criteria:

- The method should be based on cost causation. Cost causation means a causal relationship exists between the basis used to allocate a cost and the cost incurred. Costs are recognized as being caused by a service or group of services if (i) the costs are brought into existence as a direct result of providing the service or group of services; or (ii) the costs are avoided if the service or group of services is not provided.
- If cost causation is inappropriate in a given situation, the method often utilized is benefits received (i.e., allocated to the business that received the benefits).
- Underlying data used for implementing the method should be obtained at a reasonable cost and be objectively verifiable in the initial and subsequent years.
- Estimates used for the allocation method should be unbiased, reasonably consistent with comparable data, and provided by employees familiar with the costs.

3 Hydro One's Current Corporate Overhead Recovery

3.1 Overview

Hydro One's Corporate Cost Allocation addresses the following considerations:

- Methods comply with the relevant provisions of the OEB Affiliate Relationships Code for Electricity Distributors and Transmitters.[6]
- Cost incurrence - The costs are needed to perform services the business requires.
- Cost allocation - The costs are appropriately allocated among businesses using cost drivers/allocation factors supported by principles of causality.
- Cost/benefit - The benefits received equal to or exceed the cost.

[6] Affiliate-Relationships-Code-ARC-Electricity-20100315.pdf (oeb.ca)

The Corporate Cost Allocation is detailed in Hydro One's 2023-27 Joint Rate Application (EB-2021-0110) within a Hydro One commissioned report by Black & Veatch relating to the Corporate Cost Allocation review undertaken in 2021.[7] This report finds the Corporate Cost Allocation continues to be appropriate for Hydro One because:

- It meets generally acceptable regulatory practices for cost allocation since it distributes costs based on cost causation, including the use of direct assignment when possible, and then using cost drivers.
- It has been accepted by the OEB.
- It has the support of Hydro One management and is understood and accepted by Hydro One, its affiliate companies, and the Transmission ("Tx") and Distribution ("Dx") businesses.
- It allows Hydro One, its affiliate companies, and the Tx and Dx businesses to determine precise charges by department and by activity. This transparency provides a basis for understanding the nature of the charges and value of the services received.
- It is well integrated with Hydro One's annual business planning process and produces reasonably stable results over time.
- It accommodates changes in Hydro One's organization and can be adapted easily to reflect those changes.

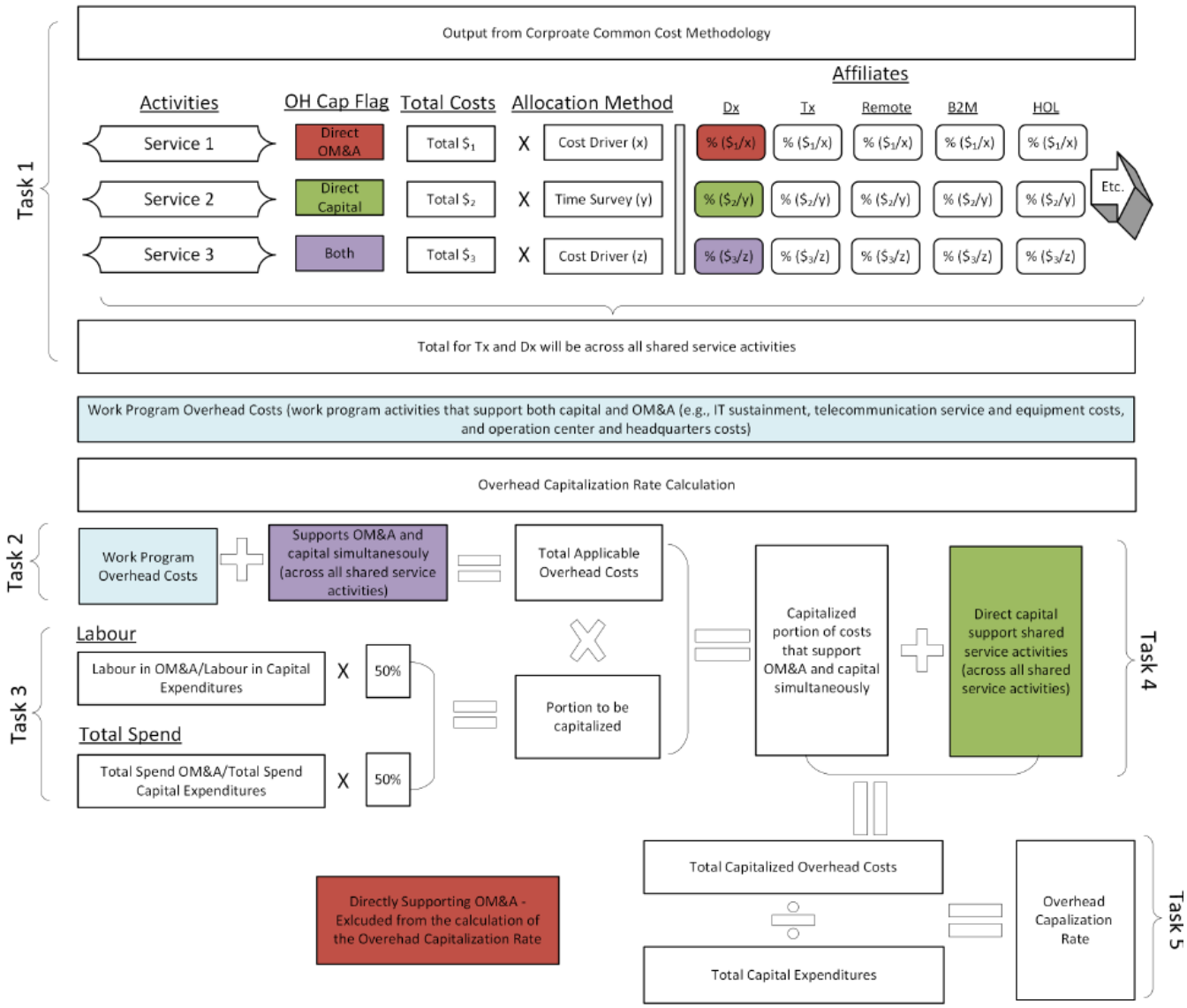
OCRs are percentages that are applied to the cost of Transmission and Distribution capital expenditures resulting in a portion of common corporate costs being included as part of capital expenditures for each business. The OCR is used to recover common corporate costs that are not directly recorded to capital expenditures due to the nature of the costs; either for employees who support capital expenditures but do not directly charge time to a specific capital project (assigned for less than three months or work on multiple projects simultaneously) or for employees who perform work that impacts both capital and OM&A projects.

The output from the Overhead Capitalization Rate Methodology consists of two percentages (Overhead Capitalization Rates for Tx and for Dx) that are applied to the costs of Tx and Dx

[7] Black & Veatch Report as filed in EB-2021-0110, Exhibit E-4-8, Attachment 1. Mr. Taylor of Atrium, in his former capacity with and as a subcontractor to B&V, has been the lead expert in connection with the B&V Report.

capital expenditures, as applicable, to recover the portion of common corporate costs that support capital expenditures for each business. This process is depicted in Figure 1 below.

Figure 1 – Overhead Capitalization Rate Methodology



4 Need for a Specific OCR for ECI-EPC Contracted Projects

Hydro One internally determines which projects will follow the ECI-EPC Delivery Model. Atrium's conclusion through interviews with Hydro One staff is that these ECI-EPC Contracted Projects are unique for several reasons: (i) their delivery model engages outsourced services much earlier in the project; (ii) they rely on outsourced services more fully and across more stages of the project; and (iii) their size and duration are higher than Standard Hydro One Tx

Projects. As such, the common corporate costs incurred by Hydro One to support these ECI-EPC Contracted Projects is of a different level than Standard Hydro One Tx Projects, as demonstrated by the following descriptions:

- A significant portion of each project's total cost relates to OE and ECI-EPC Contracted work (i.e.. Hydro One determined that 79.5% of the capital expenditures will be payments to external contractor and only 20.5% will relate to internal Hydro incurred costs).

- The EPC contractors are engaged much earlier in the process through Hydro One's ECI process and perform many of the development functions that, under the Standard Delivery Model, are undertaken internally by Hydro One.

- The projects are multi-year and significantly more extensive than most standard Transmission projects, which leads to a portion of Hydro One Common Corporate functions support being directly assigned from common corporate costs centers (e.g., most indigenous affairs, system planning, and land acquisition are all directly charging time to these projects).[8]

- For ECI-EPC Contracted Projects, the level of support provided by internal Hydro One functions per dollar of capital is significantly lower.[9]

5 Development of OCR Specific to ECI-EPC Contracted Projects

5.1 Review of Costs within OCR

One of the first steps conducted by Atrium was to review the Lines of Business that are designated as providing Common Corporate Costs directly to capital work or included as part of the overhead capital costs within the Overhead Capitalization Rate Methodology contained in Hydro One's 2023-2027 Application. The Applicable Capital Overhead costs are activities that

[8] As noted in the Black & Veatch Report as filed in EB-2021-0110, "In instances when costs associated with Common Corporate Costs can be directly attributed to work for a specific affiliate and are expected to be for a minimum period of three months, those costs are transferred via variable timesheets or automatic transfers."
[9] An estimated 23 Hydro One staff will be dedicated to ECI-EPC projects with ~$500M annual capital expenditures, compared to ~4,200 Hydro One transmission staff (OEB application EB-2021-0110, Appendix 2-K) supporting ~$1,500M annual capital expenditures (EB-2021-0110, O-01-02, Table 4).

support both OM&A and capital and are split between (a) costs that remain in OM&A and (b) costs that will be included in the Overhead Capitalization Rate calculation by multiplying the Total Applicable Overhead Costs by a ratio developed using a 50/50 weighting of the Labour Content-Capital Ratio and the Total Spending-Capital Ratio.

Hydro One personnel indicated that employees within the Lines of Businesses included as Direct Capital in the Overhead Capitalization Rate Methodology will directly charge to these ECI-EPC Contracted Projects. These include Indigenous Relations, Planning, and System Control.

A second review was conducted to ascertain the methods used to assign the overhead capital costs to the Transmission business. Those allocation methods are provided below:

- Direct Assignment - Time Survey
- Capital, Labour, Revenue
- Headcount
- Internal - Total Cost Center Labour (non-labour)
- Program & Project Costs
- Project Costs Capital
- Union Employee Headcount
- Labour Costs
- Board of Directors Labour Costs
- Information System Direct Assignment
- Defined Contributions Headcount

While the Overhead Capitalization Rate Methodology uses cost drivers to allocate Direct Capital and Applicable Capital Overhead costs to the Transmission business, there is no separation between the projects within the Transmission business. However, information is available on the split of these cost drivers between ECI-EPC Contracted Projects and all other Standard Hydro One Tx Projects. This information was gathered and used to further disaggregate the allocation of Common Corporate Costs across different types of Transmission projects.

5.2 Disaggregate Transmission Related Direct Capital Costs & Applicable Capital Overhead Costs using Sub-Allocation Factors

As indicated above, the Common Corporate Costs allocated to the Transmission business relate to two distinct types of costs (1) Direct Capital - employees who support capital expenditures but do not directly charge time to a specific capital project, and (2) Overhead Capital - employees who perform work that impacts both capital and OM&A projects. The proposed method of developing an OCR for ECI-EPC Contracted Projects is first to disaggregate the Transmission related direct capital and overhead costs between those that support the ECI-EPC Contracted Projects and the Standard Hydro One Tx Projects. Sub-allocation factors were

developed for each allocation method used in the Corporate & Shared Cost Allocation Methodology to disaggregate these costs. Figure 3 below maps the allocation factors used in the Corporate & Shared Cost Allocation Methodology to initially assign these costs to the Transmission business and the sub-allocation factors used to disaggregate costs between ECI-EPC Contracted and the Standard Hydro One Tx Projects. As mentioned above, most employees within the Line of Business (1) Indigenous Relations, (2) Planning, and (3) System Control are directly charging costs in support of these ECI-EPC Contracted Projects. These costs are allocated to the Transmission business using the allocation method 'Direct Assignment – Time Survey,' and the sub-allocation factor for these costs is 'Direct Assignment to Non-ECI.' There are additional costs within the allocation method 'Direct Assignment – Time Survey' relating to Facilities which was based on a headcount allocation between Transmission and Distribution, and the proposed method is to use Headcount as a sub-allocation factor for these Facilities' costs.

Figure 2 – Disaggregation of Tx Related Direct Capital Costs & Applicable Capital Overhead Costs

Allocation Method	Sub-Allocation Factor
Direct Assignment - Time Survey	Direct Assignment to Non -ECI, Headcount for Facilities
Capital, Labour, Revenue	Capital, Labour (50/50)
Headcount	Headcount
Internal - Total Cost Center Labour (non-labour)	Labour Costs
Program & Project Costs	Program & Project Costs
Project Costs Capital	Project Costs Capital
Union Employee Headcount	Union Employee Headcount
Labour Costs	Labour Costs
Board of Directors Labour Costs	Capital, Labour (50/50)
Information System Direct Assignment	Headcount
Defined Contributions Headcount	Headcount

Using a multi-factor allocation to allocate costs that cannot be directly charged and for which a single cost allocation factor cannot be easily identified is a widely respected and common practice across the utility industry. The Corporate & Shared Cost Allocation Methodology uses a three-factor formula, with each factor equally weighted, and is generally referred to as the Massachusetts Formula, where the three components of the factor are representative of (1) Capital, (2) Revenue, and (3) Labour. These costs are further disaggregated using a 50/50 weighting of capital and labour given the insufficiency of using revenue as a sub-allocation factor (i.e., ECI-EPC Contracted Projects may not have revenue for several years). The result of

this process for the budget plan years (2023-2027) is a total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects.

5.3 Calculate OCR for the Portion of ECI-EPC Contracted Projects Fully Outsourced to OEs and EPCs

The resulting total Direct Capital and total Applicable Capital Overhead Costs associated with ECI-EPC Contracted Projects are then utilized in an OCR Calculation identical to the OCR Calculation used for the Tx business as approved in Hydro One's 2023-2027 Application. The OCR Calculation is calibrated to contain inputs (e.g., total capital expenditures) relating only to ECI-EPC Contracted Projects. This aligns the numerator (i.e., the allocation of costs to these ECI-EPC Contracted Projects) with the denominator (i.e., total capital associated with ECI-EPC Contracted Projects). The resulting OCR for the 79.5% of costs associated with external contractor payments averaged 1.0% over five years.

5.4 Develop Blended Rate for ECI-EPC Contracted Projects

To account for the fact that 79.5% of the costs associated with ECI-EPC Contracted Projects relate to external contractor payments and 20.5% relate to internal Hydro One incurred costs, a blended rate was developed. This blended rate was calculated using the OCR for the 79.5% of costs associated with external contractor payments (described in Section 5.3) weighted at 79.5% and the standard delivery Tx OCR weighted at 20.5%. The results are shown in Figure 4 below.

Figure 3 – Blended OCR for ECI-EPC Contracted Projects

ECI-EPC Projects	2023	2024	2025	2026	2027	5-year avg	Rounded
Blended Overhead Rate	2.6%	2.6%	2.4%	2.5%	2.6%	2.5%	**3.0%**

Atrium reviewed the results of this updated OCR and evaluated the appropriateness of setting an annual OCR for ECI-EPC Contracted Projects compared to setting an OCR based on an average of overhead costs and capital expenditures. Atrium noted large deviations in forecasted capital expenditures associated with ECI-EPC Contracted Projects (e.g., the total capital expenditures for these projects can increase more than 100% without seeing a material

change in overhead costs).[10] As such, Atrium suggested a five-year average should be used for the ECI-EPC OCR rate.

5.5 Application and Monitoring of the Overhead Capitalization Rates

The blended rates shown in Figure 4 are developed based on forecast numbers and other estimates. Hydro One reviews and adjusts the OCR periodically to reflect changes in capital spending and associated support costs. Capitalized overheads are trued-up (in-year) at year-end to reflect actual results for capital implemented under the Standard Delivery Model. Given the proposed multi-year average for the ECI-EPC Contracted Projects, Atrium recommends Hydro One annually evaluate the OCR calculation for each year and ascertain if the OCR for the 79.5% of costs associated with external contractor payments used in the blended rate should be updated.

6 Conclusions and Recommendations

Atrium recommends that Hydro One adopt a blended OCR based on the analyses conducted and described in Section 5 of this report. The recommended methodology and resulting OCR reflect the level of common corporate costs provided to these ECI-EPC Contracted Projects and are consistent with the following guiding regulatory principles:

- Defensible Cost Causation: To conform to regulatory principles, the methodology should show a causal link between recovery of overhead and facilitation costs and capital activity.
- Distinguishable Costs: The overhead costs should be distinguished from those directly charged to these projects (i.e., no duplication of costs and distinct sets of costs to be included in overhead).
- Transparency: The methodology and calculations should be easy to follow and understand by internal users and external reviewers.
- Stability: The methodology should remain stable from year-to-year and not result in disproportionately large variations.

[10] This underscores the nature of these projects; that early involvement of third-party EPC contractors can be leveraged to undertake large capital expenditure projects with little additional overhead costs being incurred directly by Hydro One.

- Accuracy of Underlying Data: Any data used in the methodology should be accurate and able to be relied upon for the purposes intended (i.e., provide an appropriate measure and reasonable approximation of the underlying volume of activity or output).
- Flexibility/Adaptability: The methodology should accommodate changes in organizational structure, availability of data, business processes, and information systems with reasonable ease. Where possible, the method should automatically adjust for changes in circumstances (i.e., reconciliation processes).
- Cost-effectiveness: Methodologies should be cost-effective to implement. Additional accuracy may require significant incremental cost; thus, an appropriate balance is required between precision and cost, in relation to both implementation and ongoing costs.

PROCUREMENT MANAGEMENT

1.0 OVERVIEW

This Exhibit sets out the procurement management processes that Hydro One employs to source the materials and services required to execute the company's operations, maintenance, and capital delivery.

The 2023-2027 rate period has been impacted by unprecedented market forces, global supply constraints, geopolitical instability, escalating tariffs, high demand, and sustained inflation, which have significantly increased the cost of key electrical equipment and materials. The strategies, processes, and governance structures described in this Exhibit represent Hydro One's disciplined response to these market forces, designed to deliver on the Supply Chain Guiding Principles and rate period priorities.

This Exhibit is organized as follows: Section 2.0 sets out the Guiding Principles and Priorities, Section 3.0 describes the Category Management Framework, which includes the company's approach to Strategy Development, Category Execution, Contract Management, and Supplier Management. Finally, Section 4.0 summarizes the results of an independent review of Hydro One's supply chain practices by Wood Mackenzie.

For further information on how Hydro One applied its procurement management processes to address the unprecedented market forces in the current rate period, see SPF Section 1.8, section 1.8.3 and for information on Supply Chain productivity savings, see SPF Section 1.4, section 1.4.3 and attachment 1.

2.0 SUPPLY CHAIN - GUIDING PRINCIPLES AND PRIORITIES

Hydro One's Supply Chain activities are guided by a set of enduring principles that apply regardless of market conditions, investment cycles, or rate periods. These Guiding Principles define how decisions are evaluated and the trade-offs that must be managed in serving customers. They are stable over time and do not change in response to short-term market dynamics.

At times of market stability, these principles support efficient, predictable sourcing and contract management. During periods of volatility or supply constraint, they provide discipline and consistency in determining how Hydro One responds while continuing to meet its obligations to customers.

Hydro One's Supply Chain activities are guided by the following enduring principles:

Value for Money

Supply Chain decisions seek to minimize the total lifecycle cost of materials and services while maintaining the required performance, reliability, and quality. This principle recognizes that procurement decisions directly affect customer rates and require disciplined cost management rather than a sole focus on the lowest initial price.

Material and Services Readiness

Materials and services required to operate, maintain, restore service and expand the electricity system must be available when needed to support safe, timely, and reliable service. This principle governs decisions related to category strategy, inventory, supplier diversification, and long lead time procurement.

Safety, Quality, and Compliance

Supply Chain decisions must uphold Hydro One's safety, quality, environmental, and regulatory obligations across the full supplier lifecycle. This principle is non-negotiable and applies equally to sourcing, contracting, and supplier performance management activities.

Stewardship and Accountability

Supply Chain activities must be governed with integrity and accountability, with clear ownership for performance, risk management, and outcomes. This principle reflects Hydro One's responsibility to manage expenditures prudently while conducting procurement activities in a manner that is responsible, inclusive, and aligned with broader corporate, regulatory, and public interest obligations. This includes consideration of Indigenous

participation, environmental and sustainability objectives, and ethical business practices across the supplier lifecycle.

For further information, Hydro One's Supply Chain Policy is included as Attachment 1 to this Exhibit. The Policy applies to Hydro One and its subsidiaries, all of which are required to adhere to the same procurement policies, procedures, and governance requirements. In addition, Hydro One ensures that transactions between affiliated entities are undertaken in compliance with the Affiliate Relationships Code and are subject to the applicable controls, oversight, and requirements established thereunder.

2.1 SUPPLY CHAIN PRIORITIES FOR THE 2028–2032 PLANNING PERIOD

While Hydro One's Guiding Principles remain constant, the way they are delivered in practice depends on prevailing conditions. The 2028–2032 planning period is expected to continue to be characterized by supply constraints, elevated demand for electrical equipment, cost pressures, and increased delivery risk associated with large-scale capital investment.

In this context, Supply Chain has established a set of priorities that reflect where emphasis is required to deliver on its Guiding Principles in the current environment. These priorities do not replace the principles; rather, they represent how the principles are operationalized in response to market conditions.

Supply Chain Priorities

The following priorities guide Supply Chain activities during the 2028–2032 planning period and are addressed in the subsections that follow:

1. **Financial Stewardship** – Maintaining cost management practices to support customer affordability while navigating inflationary and market-driven cost pressures.
2. **Business Enablement** – Ensuring that materials and services are available in the right quantity and at the right time to support operations, maintenance, and capital delivery.

3. **Supplier Partnerships & Performance Management –** Building and managing structured supplier relationships that support performance, accountability, supply reliability, and continuous improvement.
4. **Indigenous Procurement –** Advancing Indigenous participation in procurement in a structured and transparent manner consistent with Hydro One's broader commitments and policies.
5. **Canadian- and Ontario-First Procurement –** Supporting domestic and Ontario-based suppliers where competitive, while maintaining value for customers and supply resilience.
6. **Supply & Delivery Risk Management** – Identifying, monitoring, and mitigating supply, cost, and delivery risks across the supplier lifecycle to protect program execution and customer outcomes.
7. **Health, Safety, Environment, and Sustainability** – Reinforcing safety, environmental, and sustainability expectations in supplier qualification, sourcing decisions, and ongoing performance management.

The sections that follow describe how these priorities are executed through Hydro One's Category Management Framework.

2.1.1 FINANCIAL STEWARDSHIP

In an environment where external market conditions continue to place upward pressure on input costs, Supply Chain's role is to mitigate these cost pressures through disciplined category strategies, sourcing approaches, and life cycle management. This includes decisions that improve cost predictability, reduce rework and inefficiency, limit exposure to volatility, and avoid costs associated with poor performance, delivery delays, or misaligned specifications.

Supply Chain achieves reduced total cost of ownership through activities under this priority such as:

1. Using competitive sourcing to achieve optimal market pricing and commercial terms by creating competitive tension amongst suppliers for contracts and leveraging external market data such as benchmarking and indexes to drive pricing negotiations.
2. Long term Demand Planning, which enables more efficient sourcing strategies, improved production alignment, and reduced fragmentation across contracts and projects;
3. Commercial structures that manage cost volatility and risk, including the use of cost adjustment methodologies, multi-year arrangements, and shared risk mechanisms that reduce unexpected cost escalation and avoidable risk premiums over the life of contracts;
4. Specification and requirement optimization, worked jointly with Engineering and the Lines of Business, to align designs with industry standards, reduce unnecessary complexity, and lower installation, maintenance, and lifecycle support costs; Improved schedule and delivery reliability, which reduces indirect costs associated with work stoppages, resequencing, emergency procurement, and premium logistics; Proactive supplier and contract management, which reinforces performance accountability, reduces defects and rework, and limits downstream cost exposure over the life of capital assets; and,
5. Lifecycle feedback loops that use performance and market insights to continuously refine category strategies and sourcing approaches, preventing the recurrence of avoidable cost drivers.

Through these mechanisms, Supply Chain contributes directly to lowering the cost of delivering Hydro One's capital and operating programs, even in periods of sustained inflation and supply constraint.

In 2025, Supply Chain realized approximately $3.5 million in savings from conductor hardware procurement as part of the Enterprise Cost Optimization (ECO) Program described in SPF 1.4, section 1.4.3. These savings were achieved by partnering with the Transmission Lines team to review and adjust technical standards to align with industry

norms. By identifying competitive suppliers and market-based pricing for new hardware, Supply Chain ensured that Hydro One benefited from fair, transparent, and cost-effective sourcing without compromising performance or safety.

Building on this success, Supply Chain is expecting to generate over $3.8 million in additional savings through strategic sourcing in 2026. Supply Chain achieved measurable cost reductions during the procurement of 13 power transformers by running a competitive sourcing process that enabled true like-for-like comparisons across suppliers. The team leveraged pricing transparency and robust commercial negotiations, challenging suppliers to go beyond existing contract pricing and submit their best and final offers. This disciplined approach ensured Hydro One secured optimal pricing in a highly constrained market.

Further savings and value were realized through the refurbishment of existing power transformers. Refurbished units offer the same operational life as new transformers while significantly reducing material waste and environmental impact. This approach not only supports Hydro One's sustainability objectives but also improves access to critical equipment in a supply-constrained market.

Supply Chain also applies these cost management practices to its own costs. It has been able to reduce the Supply Chain functional cost that is allocated to the business, including through: volume rebates, early pay discounts and investment recovery. These activities are further described in Exhibit C-09-04, section 3.0. The financial benefits generated through these programs are reflected in the approved investment plan and cost recovery mechanisms.

2.1.2 BUSINESS ENABLEMENT

In the 2028–2032 planning period, ensuring the availability of materials and services continues to be a central priority for Supply Chain. This is driven by strong growth in capital investment, sustained demand for electrical equipment, and extended manufacturing lead

times across key asset categories. Without sufficient capacity and forward planning, projects are delayed, costs escalate, and reliability risks increase.

Under this priority, Supply Chain focuses on ensuring that:

- Critical materials and services are available in the quantities and timeframes required to complete work;
- Procurement activity anticipates demand rather than reacting to shortages; and,
- Execution risks arising from supply constraints are identified early and actively managed.

Strong and unprecedented demand for engineered electrical equipment has driven significantly longer manufacturing lead times, in some cases extending to multiple years for critical assets. This has made supply planning more consequential than ever. In the current rate period, Supply Chain has responded with long term category strategies and targeted tactical measures, such as the Supply Risk Taskforce, as described in the Category Management Framework in Section 3.0.

Key elements of this priority include:

- Maintaining sufficient supply capacity across critical material and service categories to support Hydro One's capital program and ongoing operations;
- Aligning sourcing strategies and procurement timing with the five-year investment plan so that materials and services are secured ahead of need;
- Managing inventory and warehousing to ensure materials are available where and when required, without unnecessary carrying costs; procuring long lead time, highly engineered equipment in advance of construction execution to secure manufacturing capacity and support on-time delivery; and,
- Leveraging Demand Planning to forecast material and service requirements and to identify supply risks early, so that sourcing decisions are grounded in accurate, forward-looking information.

2.1.3 SUPPLIER PARTNERSHIPS AND PERFORMANCE MANAGEMENT

In the 2028–2032 planning period, the scale, complexity, and delivery risk of Hydro One's capital and operating programs require that supplier performance, reliability, and responsiveness be a top priority. As supply markets tighten and execution risk increases, effective supplier management is critical to maintaining schedule, controlling costs, and protecting system reliability.

Supply Chain has placed increased focus on how suppliers perform once contracted, using structured relationship and performance management practices to support reliable delivery, surface issues early, and address performance shortfalls before they affect program execution.

Key elements of this priority include:

- Segmenting suppliers into strategic and operational tiers based on spend, criticality, and risk, and tailoring the intensity of oversight accordingly;
- Using a structured Supplier Relationship Management (SRM) program for Strategic suppliers to support transparency, issue resolution, capacity planning, and alignment on delivery expectations;
- Holding regular executive-level business review meetings with strategic and operational suppliers to review performance trends, forward capacity, cost drivers, and emerging risks; and,
- Applying standardized Supplier Performance Management (SPM) processes to track performance, drive corrective action where required, and inform sourcing and risk decisions.

The detailed application of supplier segmentation, SRM, and SPM, including scorecards, escalation mechanisms, and feedback loops into category planning, is described in Section 3.4.

2.1.4 INDIGENOUS PROCUREMENT

Hydro One is committed to building and maintaining relationships with Indigenous Peoples and communities based on mutual respect. As part of this relationship, Hydro One is also committed to creating meaningful economic opportunities through its procurement activities.

Key elements of this priority include:

- Incorporating Indigenous participation considerations into category strategies and sourcing plans, based on the nature of the work, market capability, and risk profile;
- Using established procurement mechanisms, including set-aside processes and participation requirements, where appropriate and consistent with policy;
- Working with the Lines of Business and Indigenous Relations to identify opportunities that are suitable for Indigenous supplier participation without compromising safety, quality, or delivery outcomes; and
- Applying the same performance, safety, and compliance expectations to Indigenous suppliers as to all other suppliers to ensure fairness, accountability, and value for customers.

For more information on Indigenous procurement, please refer to SPF Section 1.6 – Attachment 2, Section 3.0.

2.1.5 ONTARIO AND CANADA FIRST PROCUREMENT

Supporting Canadian and Ontario-based suppliers is a Supply Chain priority in the 2028 to 2032 planning period because it makes strong business sense for the delivery of Hydro One's capital and operating programs. From a procurement perspective, a strong local supply chain improves supply resilience, reduces exposure to tariffs, foreign exchange fluctuations, and cross border disruptions, and lowers delivery risks associated with overseas shipments. Where competitive domestic supply is available, relying on local suppliers also supports more reliable scheduling and timely delivery.

In the current market environment, domestic sourcing can reduce transportation risk, improve responsiveness, and support continuity of supply for critical materials and services. At the same time, Supply Chain applies this priority within a procurement framework that preserves competitive tension and maintains value for customers.

Key elements of this priority include:

- Prioritizing Ontario and Canadian-based businesses for materials and services on critical projects, consistent with broader government and Hydro One objectives. All new category strategies are reviewed through a Canada First lens & Canadian ownership, resources and manufacturing considerations are incorporated into competitive procurement evaluations. In addition, Hydro One continues to reinforce Canadian content expectations with existing suppliers and supply chain partners, including requests for suppliers to identify opportunities to increase local content. Promoting opportunities with Canadian manufacturers, including suppliers in specialized sectors such as power transformers, supports domestic production and employment. For example, Hydro One partnered with Northern Transformers to support a local manufacturing plant in Ontario.
- Collaborating with Electricity Canada and peer utilities to align specifications with Canadian industry standards, creating conditions that support bulk procurement and domestic supplier development.
- Requiring contractors to provide Ontario and Canadian-based suppliers the opportunity to bid on relevant subpackages such as steel structures, conductors, hardware, and electrical equipment, with Ontario options prioritized where available.

This priority does not require supplier selection based on geography alone. Supply Chain decisions continue to be based on competitiveness, capability, and risk, with Canadian and Ontario-based sourcing considered as one factor within an overall value-for-money assessment.

2.1.6 SUPPLY & DELIVERY RISK MANAGEMENT

Supply and delivery risk management is a key Supply Chain priority in the 2028–2032 planning period, reflecting heightened uncertainty in global supply markets and increased delivery risk associated with large-scale capital execution. Unmanaged supply risks can translate directly into delayed projects, cost escalation, and challenges in meeting service and reliability expectations.

Supply Chain's role is to identify, monitor, and mitigate risks related to material availability, supplier capability, and delivery timing before they affect program execution. This priority focuses on early risk visibility and proactive intervention rather than reactive escalation.

Key elements of this priority include:

- Maintaining a diversified supply base across all material and service categories to protect supply continuity and reduce the risk of cost increases from over-reliance on any single supplier or region.
- Integrating risk monitoring into every stage of the Category Management life cycle, from strategy development through contract administration and supplier performance management, so that risk is never treated as a one-time consideration.
- Applying contractual mechanisms, such as cost adjustment methodologies and commercial protections, to improve transparency and manage exposure to volatile market conditions
- Using early ordering, production slot commitments, and proactive inventory procurement for long-lead-time equipment, to ensure materials are secured well in advance, and project delivery is not constrained by supply timing.
- Coordinating risk monitoring and response activities through structured cross-functional forums, including the Supply Risk Taskforce, to ensure emerging risks are identified and addressed in a timely manner.

Supply and delivery risk management is embedded across the Category Management Lifecycle rather than treated as a standalone activity. The specific tools and processes used to manage these risks, including assurance of supply measures, supplier

performance management, and contract management practices, are described in Section 3.0.

2.1.7 HEALTH, SAFETY & ENVIRONMENTAL AND SUSTAINABILITY

Health, safety, environmental, and sustainability considerations are a core Supply Chain priority and represent a non-negotiable foundation for procurement activities. Supply Chain decisions support Hydro One's safety culture, regulatory obligations, and environmental responsibilities, while ensuring that materials and services are sourced in a responsible, ethical, and compliant manner.

This priority is focused on embedding safety, environmental, and sustainability considerations into sourcing decisions from the outset, rather than treating them solely as post-award compliance activities. This ensures that suppliers selected to support Hydro One's operations and capital programs can meet required standards throughout the lifecycle of their contracts.

Key elements of this priority include:

- Integrating health, safety, environmental, and sustainability considerations into category strategy development, supplier qualification, and sourcing evaluations;
- Establishing clear expectations for supplier performance related to safety, environmental practices, and regulatory compliance as part of contract formation;
- Working with Engineering, the Lines of Business, and Corporate functions to ensure procurement requirements align with Hydro One's applicable safety standards and environmental policies; and,
- Applying consistent governance to ensure that safety and sustainability requirements are not compromised in the pursuit of cost, schedule, or capacity objectives.

Ongoing monitoring, performance management, and enforcement of supplier health, safety, environmental, and sustainability obligations are addressed through Contract Management and Supplier Management processes described in Sections 3.3 and 3.4.

3.0 CATEGORY MANAGEMENT

Hydro One delivers all Supply Chain activities through a single, integrated Category Management Framework. This framework translates the Guiding Principles and rate period priorities described in Section 2.0, into sourcing, contract management, and supplier management decisions that support the delivery of the capital and operating programs.

Category Management group materials and services into distinct categories based on shared business needs, technical requirements, supply bases, and go-to-market strategies, managing them in a coordinated, end-to-end manner over time. This provides a structured, repeatable approach to planning and managing the materials and services that Hydro One relies on across its distribution and transmission systems. It enables Supply Chain to take a long-term view of demand, market conditions, supplier capability, cost drivers, and risk, rather than managing procurement as a series of isolated transactions.

At Hydro One, Category Management is implemented through a four-stage lifecycle that governs how categories are planned, executed, and managed over time:

1. **Category Strategy Development** - where business requirements, demand forecasts, and market conditions are assessed and sourcing strategies are developed in alignment with our Guiding Principles and Priorities;
2. **Strategy Execution** - where the Sourcing Plan is developed and executed, including; competitive sourcing events, commercial negotiations, and contract awards;
3. **Contract Management -** where commercial agreements are managed for the duration of the contract, to ensure value, compliance, and contractual accountability; and,
4. **Supplier Management -** where supplier relationships and performance are actively managed to support reliable delivery and deliver improved outcomes and value for our customers.

This lifecycle operates as a continuous loop. Insights gained through contract outcomes, supplier performance, and market experience feed back into future category strategies, enabling Supply Chain to adapt to changing business needs and market conditions while maintaining discipline and consistency in decision-making.

Figure 1 illustrates Hydro One's Category Management Lifecycle and the relationship between the four stages described above.

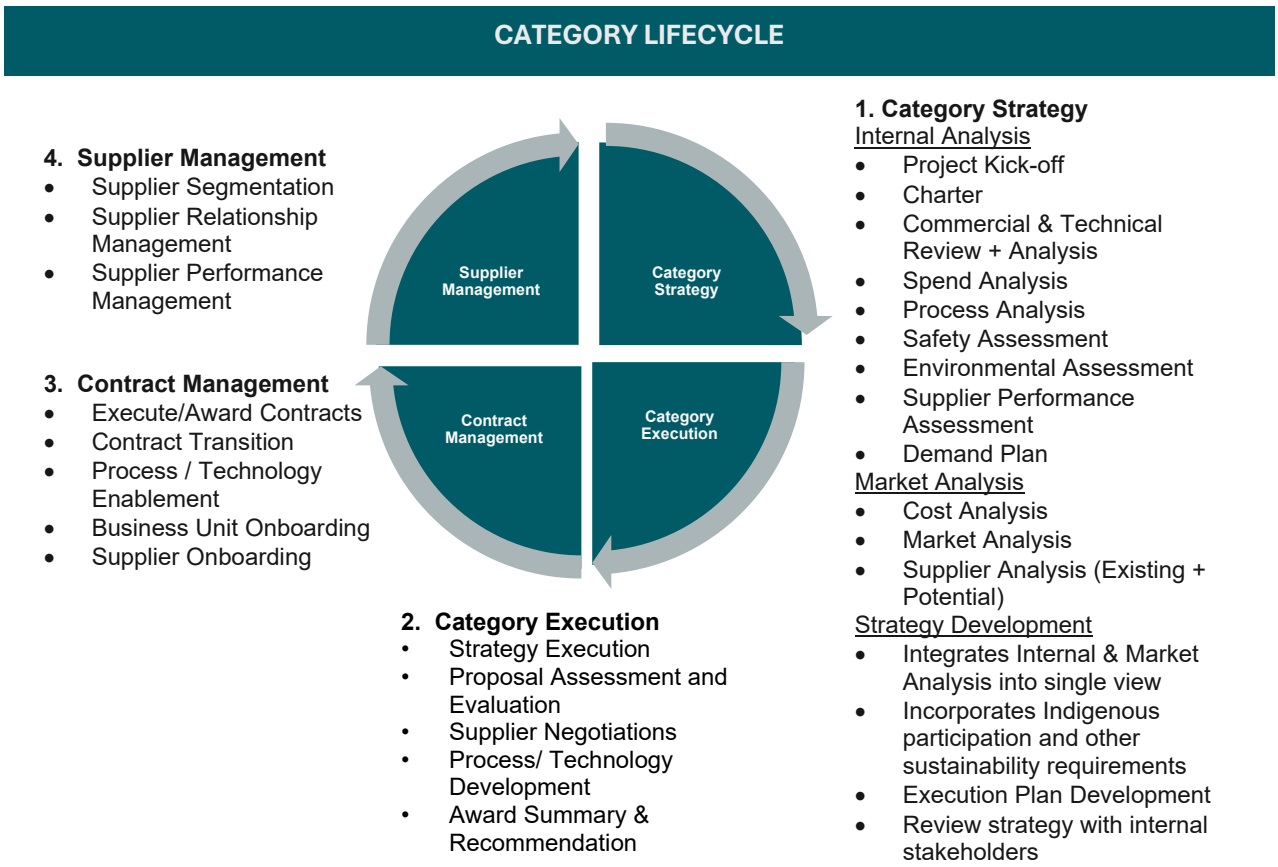


Figure 1: Chart depicting Hydro One Supply Chain's Category Lifecycle

3.1 CATEGORY STRATEGY

Every material and service category managed by Hydro One operates under a defined category strategy. These strategies establish the planned approach for each category over a multi-year horizon and provide a structured basis for sourcing, contract management,

and supplier management decisions. The scope and level of activity associated with each strategy are deliberately scaled based on the category's potential impact to the Guiding Principles and Priorities.

Categories assessed as having the greatest opportunity to positively impact our priorities are more likely to be advanced for execution through the Sourcing Plan in year (Sourcing Plan is described in more detail in Section 3.2 Category Execution). Conversely, Categories with lower relative impact, or those that are performing well under an existing strategy and commercial arrangement, may require only limited strategy refresh or continued operation under existing contracts. This may also be dictated by the prevailing external market conditions where executing a new strategy would not materially improve outcomes. Prioritizing categories in this manner allows Supply Chain resources to remain focused on the categories where strategic intervention will deliver the greatest benefit.

Internal Analysis and Market Analysis.

For any category being sourced, the strategy development process follows two sequential analytical phases: Internal Analysis and Market Analysis.

Internal Analysis: Category Leads establish a comprehensive understanding of current-state operations by: developing a category charter, conducting commercial and technical reviews and analysis (i.e., category spend analysis, process analysis, safety and environmental assessments, supplier performance assessment), and developing a category Demand Plan. Relevant stakeholders from across the Lines of Business are engaged throughout this phase to ensure that business requirements, technical standards, and operational priorities and pain-points are fully understood and reflected in the strategy.

Market Analysis: Category Leads conduct a thorough analysis of cost drivers and market trends, complete a competitive marketplace overview, and identify existing and potential suppliers. In the current market environment, defined by historically elevated equipment costs, supply shortages, and geopolitical disruption, this analysis is particularly critical. It ensures that sourcing strategies are calibrated to current realities, including commodity

price levels and trajectories, manufacturing capacity constraints, tariff impacts, and the risk profile of different supply channels.

Strategy Development

The Strategy Development phase brings together the insights from internal analysis and market analysis to define the most effective and appropriate approach for each category. Internal analysis establishes a clear understanding of business requirements, demand outlook, operational criticality, historical performance, and lessons learned from existing contracts and suppliers. Market analysis complements this by assessing supply availability, cost drivers, supplier capability, competitive dynamics, and broader market risks. Using these inputs, the category strategy defines how the category will be managed to maximize outcomes aligned with Hydro One's Guiding Principles and Priorities. This includes determining the appropriate sourcing approach, commercial and contract structures, supplier engagement model, risk mitigations, and timing of market activity.

Where analysis indicates that strategic intervention can materially improve outcomes, the strategy will typically recommend proactive market engagement and be positioned for execution through the Sourcing Plan. Where the analysis indicates that outcomes are being effectively achieved under existing arrangements, the strategy may instead recommend maintaining the current approach, targeted refinements, or re-sequencing future sourcing activity.

Through this disciplined approach, Category Strategy Development ensures that sourcing decisions are evidence-based and targeted, and that procurement actions focus on the categories where strategic intervention will deliver the greatest impact.

3.2 CATEGORY EXECUTION

Category Execution is the stage where approved category strategies are translated into action. At this stage, Supply Chain operationalizes the strategic choices defined during Category Strategy Development by determining which categories move forward for execution, sequencing and resourcing those activities through the Sourcing Plan, and

executes sourcing events in the market. This ensures that procurement activity is deliberate, coordinated, and aligned to the outcomes identified in each category strategy, while maintaining flexibility to respond to changing conditions.

3.2.1 SOURCING PLAN DEVELOPMENT AND PRIORITIZATION

The Sourcing Plan is the primary mechanism through which approved category strategies are sequenced and advanced for execution. It translates strategic intent into a coordinated, multi-year execution roadmap that identifies which categories will be taken to market, when, and at what level of effort, based on their expected ability to deliver against Hydro One's Guiding Principles and Priorities.

The Sourcing Plan is developed on a rolling five-year horizon. The plan has detailed execution sequencing and resource planning for the first two years and a forward-looking view of anticipated activity in years three through five. This approach provides sufficient visibility to support capital planning and supplier engagement while preserving flexibility to respond to changing business needs and market conditions.

Before execution, the Sourcing Plan is reviewed and validated with the Lines of Business to confirm alignment with capital program timelines, operational requirements, and execution readiness. It serves as the execution baseline for Category Execution activities, while remaining subject to periodic in-year refreshes to reflect changes in demand, market dynamics, or emergent risks.

The shift toward large-scale capital program delivery is reshaping how Hydro One approaches procurement. Traditionally, the procurement model was optimized for steady, relatively stable demand, longer planning horizons, and established supplier arrangements. While effective in that context, it is less suited to environments that require rapid scaling, flexibility, and responsiveness. The addition of new transmission lines and increased customer connections, including those outside this rate application, introduce a different set of demands. These include significantly higher volumes of materials and

equipment, compressed timelines, and increased reliance on external contractors, all of which require a more agile and adaptive sourcing approach.

As the capital program grows, supplier and contractor capacity across the entire supply chain becomes increasingly important to reliably serve customers. Hydro One is preparing for this by expanding the supplier base, improving visibility into demand including materials and services procured through contractors, and building stronger, longer-term supplier relationships aligned to Hydro One's capital outlook. These actions enable Supply Chain to support sustained capital delivery while maintaining cost discipline for customers.

The following assurance of supply measures are built into category strategies and executed as part of Category Execution:

- **Diversification of Supply Base**: Category strategies maintain more than one qualified supplier for each material category to protect supply continuity and prevent any single supplier from having undue influence over pricing or availability. Where only one supplier currently exists, this is flagged during Internal Analysis and managed through a plan to broaden the supply base over time.
- **Specification Refinement and Consolidation**: Category strategies are developed in collaboration with Engineering and Technical Services teams to align specifications with industry standards and reduce variations. This increases the number of suppliers able to compete, improves manufacturing efficiency, reduces unit costs, and enables collaboration with peer utilities on common specifications.
- **Inventory Management:** Hydro One maintains on-hand inventory at its central warehouse in Orillia, and at its Operations Centres across the province for day-to-day operational needs. The Orillia facility consolidates the main warehouse, cross-docking operations, and central tools services, enabling efficient receipt and distribution of materials to project sites. For highly engineered, long-lead-time equipment such as power transformers and high-voltage circuit breakers, category strategies enable procurement into pre-purchase, hold slots, or inventory ahead of anticipated project needs to secure manufacturing capacity and support on-time project delivery.

- **Long Lead Time Equipment**: Category strategies for long lead time and critical materials include provisions for proactive inventory policy. For highly engineered, long lead time equipment such as power transformers and high voltage circuit breakers, category strategies enable procurement into pre purchase, hold slots, or inventory ahead of anticipated project needs. This approach secures manufacturing capacity, supports on time project delivery, and can reduce per unit costs by committing volume ahead of peak demand periods, benefiting customers through lower overall program costs.
- **Early Ordering and Production Slot Commitments**: Category strategies identify opportunities to commit to key suppliers early, securing production slots and supporting on-time delivery of critical materials for the capital program. These commitments are coordinated with Planning and the Lines of Business to align with project timelines.
- **Collaboration with Peer Utilities**: Category strategies draw on intelligence shared with peer utilities to understand market trends, develop shared approaches, and pursue collaborative sourcing where opportunities exist. For example, Hydro One collaborated with Alectra Utilities on the Advanced Metering Infrastructure AMI 2.0 program to share market intelligence, align technical specifications, and explore coordinated sourcing leveraging our combined volumes. This collaboration has improved supply access, reduced delivery risk, and achieved competitive pricing in a constrained market.

3.2.2 SOURCING METHODS

The sourcing method for each category event is determined by the approved category strategy. Hydro One employs the following methods.

- **RFI – Requests for Information:** An RFI is a market research tool used to gather intelligence, build a supplier database, scope requirements, and estimate costs. RFIs inform subsequent competitive bid documents but do not result in an award.

- **RFP – Requests for Proposal:** A competitive bid process used when suppliers must develop and propose a solution or application. This competitive bid process is used when one or more of the following criteria are met:
    - There is a requirement for custom-made/specialized materials or services for which bidders must develop and propose a business application or solution;
    - There is a need for engineered equipment and/or construction services, and more than one option exists to address the requirement;
    - There are off-the-shelf materials where value added services are required in addition to the materials; and/or
    - An alternative solution is sought.

  An RFP may result in a Vendor of Record list with pre-established rate cards requiring a second-stage competitive process.

- **RFPQ – Request for Pre-Qualification**: A competitive process used to establish a list of qualified suppliers based on financial and technical criteria, used when Hydro One wants to work with a focused group of capable suppliers. These arrangements require a second-stage competitive process or a defined award methodology. It is used when:
    - There are opportunities to reduce costs for certain categories of materials and services by establishing strategic relationships with a small group of suppliers; and,
    - There are well established technical criteria to pre-qualify the suppliers, with specific scopes of work defined as required.

These arrangements require a second-stage competitive process involving the pre-qualified suppliers, or a strategy identifying the methodology for determining the award of work.

- **RFQ – Requests for Quotation:** A competitive bid process used when the requirement is clearly defined and the evaluation is based primarily on price and

delivery terms. This is most appropriate for standard materials and services with well-established specifications.

- **Direct Negotiation**: Direct negotiation is used when a competitive process is not feasible or when running competitive sourcing is not in the best interest of Hydro One. Examples of circumstances when negotiation with a single supplier may be most appropriate include:
    - Building key strategic supplier relationships where it is believed that a competitive process may not lead to the best solution or drive the most value for Hydro One;
    - A purchase that is of a confidential nature;
        - There is only one supplier who can perform the work without causing Hydro One to suffer an unacceptable delay or incur unreasonable costs due to another supplier's learning curve;
        - There is only one supplier capable of meeting the requirements, whether due to urgency, technical exclusivity, compatibility with existing products, intellectual property rights, statutory monopoly, or the absence of an alternative or substitute;
        - For the procurement of a prototype, or a first good or service, to be developed in the course of, and for, a particular contract for research, experiment, study, or original development, but not for any subsequent purchases.
        - Where pricing is demonstrably competitive based on market intelligence, historical pricing, or benchmarking and negotiation is expected to achieve best value for Hydro One; or
        - Where direct negotiation supports alignment with approved corporate priorities, such as Indigenous procurement or strengthening Canadian based supply chains, while still delivering value for money.

3.3 CONTRACT MANAGEMENT

Contract Management is the third stage of the Category Lifecycle. It ensures that the commercial intent established through strategy development and execution is realized in practice by administering contracts to protect value, support delivery, and maintain supplier accountability over the life of the contract.

Contract Management operates across two horizons. Strategically, it ensures that long-term commercial arrangements remain fit for purpose as business needs and market conditions evolve, including through governed review processes and managed extension decisions. Tactically, it ensures day-to-day compliance, timely and accurate payment, and timely resolution of commercial issues as they arise, including quality disputes and supplier performance shortfalls.

Key Contract Management activities include:

1. Contract transition and commercial integrity: ensuring accurate and complete handover from Category Execution, including capture of key commercial terms, pricing mechanisms, and performance obligations so that negotiated outcomes are implemented as intended.
2. Governed contract administration and compliance: maintaining contract compliance through standard controls, periodic cost accuracy checks, and review of supplier adherence to pricing and commercial obligations.
3. Cost transparency and consistent application of contract mechanisms: administering contractual pricing mechanisms, including indexed pricing where used, to ensure transparency and fair application of contract terms as market conditions change.
4. Performance accountability and commercial issue resolution: addressing disputes and performance shortfalls in a timely manner and applying commercial remedies where required, including suspension of work, fees at risk, liquidated damages, or other remedies available under contract.
5. Lifecycle feedback and continuous improvement: tracking contract consumption against forecasted spend, identifying variances, and feeding performance and

commercial insights back into the category planning cycle so that future strategies reflect lessons learned from contract outcomes.

3.3.1 SUPPLY RISK TASKFORCE

Supply and delivery risk management is an inherent consideration across all stages of the Category Lifecycle. In addition to the category-specific risk mitigations embedded in category strategies, sourcing plans, and contracts, Hydro One maintains the Supply Risk Taskforce (SRT) as a cross-functional mechanism to support ongoing risk visibility and coordinated response to emerging risks across the Supply Chain portfolio.

The SRT provides a structured forum for identifying, assessing, and monitoring emerging supplier, market, and delivery risks that may affect contract performance or program execution. It brings together Supply Chain and relevant Lines of Business to review information on changes in supplier financial health, manufacturing capacity constraints, commodity price volatility, tariff impacts, logistics disruptions, and geopolitical developments.

Where material risks are identified, the SRT supports coordinated mitigation actions that may include adjustments to sourcing and execution timing, engagement with alternative or additional suppliers, activation of contractual protections, or escalation into category strategy refreshes or sourcing plan updates, as appropriate. This ensures that risks are addressed proactively and consistently, rather than through isolated or reactive interventions.

For example, in 2022 Hydro One identified supply shortages for station underground cable and overhead conductor driven by supplier changes and increased market demand. Through the SRT, Supply Chain coordinated with suppliers, warehouse teams, and project stakeholders to forecast demand and execute advance purchases, reducing lead times from approximately 1.5 years. The identified risk also informed future sourcing actions, including prioritization of the 2025 wire and cable sourcing initiatives.

By operating alongside category strategy, execution, and contract management activities, the Supply Risk Taskforce strengthens Hydro One's ability to manage uncertainty and protect delivery outcomes.

3.3.2 WARRANTY AND CLAIMS MANAGEMENT

As part of the Contract Management phase, Hydro One maintains a warranty and claims process to protect the value of its capital investments and enforce supplier accountability for quality and performance outcomes. Where materials, equipment, or services do not conform to contractual requirements, warranty and commercial claim mechanisms provide a governed means to seek remediation or compensation consistent with the terms of the contract.

Warranty and claims activity is focused on resolving issues efficiently while preserving delivery and safety outcomes. Insights from warranty and claims are used to inform ongoing contract administration and future category strategy development, reinforcing continuous improvement across the Category Lifecycle.

Where a warranty does not apply but a loss has occurred, Hydro One may issue a commercial claim for liquidated damages, latent defect, design not conforming to specifications, or breach of contract.

Upon completion of the repair or remediation, applicable costs are reimbursed by the supplier in accordance with the terms of the warranty or claim settlement.

Hydro One's Warranty and Claims Management process reinforces supplier accountability for the quality and performance of the materials and services they provide, protecting the value of its capital investments.

3.4 SUPPLIER MANAGEMENT

Supplier Management is the fourth stage of the Category Management Lifecycle, but continues to run in parallel during all phases. It governs how Hydro One manages supplier

relationships and performance following contract award to support reliable delivery, manage risk, and reinforce accountability throughout the life of the commercial arrangement. Supplier Management operationalizes Hydro One's Supply Chain Guiding Principles and Priorities by ensuring suppliers perform in a manner consistent with approved strategies, contractual requirements, and a culture of continuous improvement.

Supplier Management is risk-based and proportionate. The level of engagement and oversight is scaled based on the supplier's strategic importance, criticality to operations, and potential impact on system reliability and customer outcomes. This approach enables Supply Chain to focus its most intensive relationship and performance management efforts on suppliers where performance risk is highest, while maintaining appropriate oversight across the broader supplier base.

Through structured supplier segmentation, relationship management, and performance management, the Supplier Management phase supports operational discipline from across the supplier base. Insights generated through this stage including, performance trends, capacity considerations, and emerging risks, feed back into category strategy development and sourcing decisions, reinforcing continuous improvement over time.

This section discusses supplier segmentation followed by the SRM and SPM processes.

3.4.1 SUPPLIER SEGMENTATION

As part of Supplier Management, Hydro One segments its supplier base into Strategic and Operational suppliers to ensure that relationship and performance management efforts are proportionate to risk, criticality, and potential impact on system reliability and customer outcomes.

Strategic suppliers are those whose performance is critical to Hydro One's ability to deliver its capital and operating programs. These suppliers are typically characterized by a combination of high spend, operational or technical complexity, limited alternative supply options, or direct impact on safety, reliability, and delivery timelines. Due to their

importance, Strategic suppliers are subject to enhanced relationship and performance management, including structured executive engagement and more rigorous performance oversight.

Operational suppliers comprise a broader supplier base that supports Hydro One's day-to-day operations and routine service delivery. While these suppliers remain subject to contractual requirements, safety standards, and performance expectations, the level of ongoing oversight is scaled to reflect their relative risk and impact. This approach ensures appropriate governance while enabling Supply Chain to focus its most intensive management efforts where the consequences of underperformance would be greatest.

This two-tier segmentation model enables Supply Chain to allocate resources effectively, maintain clear accountability, and apply consistent management practices, while preserving flexibility to respond as supplier risk profiles or business needs change over time.

3.4.2 SUPPLIER RELATIONSHIP MANAGEMENT (SRM)

SRM applies to Hydro One's Strategic suppliers and provides the structured engagement framework through which longer-term alignment, transparency, and delivery confidence are established. SRM is designed to support reliable execution of Hydro One's capital and operating programs by building shared understanding of future needs, surfacing risks early, and strengthening supplier capability and commitment over time.

Through SRM, Supply Chain maintains regular, disciplined engagement with Strategic suppliers beyond day-to-day contract administration. This engagement focuses on forward capacity planning, anticipated demand, market conditions, and emerging constraints that may affect delivery, cost, or reliability. By creating predictable and constructive forums for dialogue, SRM enables Hydro One and its Strategic suppliers to proactively address challenges before they affect execution outcomes.

Key elements of Hydro One's SRM approach include structured executive-level business review meetings, forward-looking discussions on capacity and delivery risks, and targeted value and improvement initiatives where appropriate. Importantly, SRM does not replace contractual accountability or performance management; rather, it complements those mechanisms by providing the transparency and strategic context required to support disciplined decision-making and coordinated risk mitigation.

Insights generated through SRM, including visibility into supplier capacity, market dynamics, and systemic risks, feedback into category strategy development and sourcing decisions supporting continuous improvement across the Category Management Lifecycle while reinforcing Hydro One's ability to deliver large-scale programs in a constrained and evolving supply environment.

3.4.3 SUPPLIER PERFORMANCE MANAGEMENT (SPM)

SPM is the mechanism through which Hydro One maintains visibility into supplier performance, identifies emerging risks, and reinforces accountability following contract award. SPM supports reliable delivery by ensuring that performance shortfalls are identified early and addressed in a disciplined and proportionate manner.

SPM is applied on a risk-based basis, with the most structured performance management activities focused on Strategic suppliers, where underperformance could have material impacts on safety, reliability, cost, or program delivery. Operational suppliers remain subject to contractual performance requirements and compliance oversight, with the intensity of ongoing performance management scaled to reflect their relative risk and criticality.

Performance monitoring draws on a combination of quantitative performance indicators and qualitative business input to provide a balanced view of supplier delivery. Where performance issues are identified, Supply Chain works with the Lines of Business to drive corrective actions, escalate issues as appropriate, and ensure accountability is maintained

in line with contractual obligations. Persistent or material performance concerns inform sourcing, contract management, and supplier relationship decisions.

Supplier performance is evaluated using a standardized Supplier Performance Scorecard that combines quantitative performance data with qualitative feedback. Strategic and Operational Partners are assessed across four performance categories. These categories and associated measures are summarized in the table below.

Operational Excellence	**Quality** – performance of goods or services to a consistent, specified standard **Service** – Factors such as on time delivery, consistency and reliability **Cost** – contribution to productivity / efficiency of operations
Cultural Alignment	**Sustainability & ESG** - metrics or initiatives that contribute to Hydro One's Corporate Sustainability goals (e.g. Indigenous Procurement) **Customer Satisfaction** - results of the Customer Satisfaction surveys for Hydro One stakeholders of the suppliers' services/products, as well as flexibility and responsiveness
Risk & Growth	**Supplier Risks** – degree to which doing business with supplier presents risks to Hydro One, e.g. supplier financial insolvency **Technology & Innovation** – degree to which supplier brings leading edge technology or processes to Hydro One **Assurance of Supply** – Suppliers ability to manage internal risks and ensure stable and cost-effective supply
Compliance	**Health & Safety** - compliance with all HSE requirements and demonstrated safe execution of contract **Regulatory compliance** - (e.g. Cyber Security, industry specific legislation etc.)

Insights generated through SPM feedback into category strategy development and sourcing decisions reinforcing continuous improvement across the Category Lifecycle.

3.4.4 CATEGORY MANAGEMENT IN PRACTICE: OPERATED EQUIPMENT SERVICES

The Operated Equipment Services category shows how Hydro One’s Category Strategy and Execution processes work in practice, and how the Guiding Principles connect to outcomes that benefit customers.

This category covers a market with strong demand driven by electrification, load growth, and capital program expansion. The Category Strategy process engaged stakeholders across Transmission Lines, Stations Construction, Environmental Services (Waste Management), Lines Engineering, Indigenous Relations, Supply Chain Sourcing, and Contract Management. Involving the Contract Management team ensured that practical knowledge from prior contracts was incorporated into the strategy, including lessons on service delivery, contract structure, and operational requirements.

The Category Strategy focused on four objectives that directly serve customers: expanding the supplier pool and regional coverage to strengthen supply and increase supplier competition; modernizing the contract and commercial structure; improving value through competitive rates; and increasing Indigenous participation in line with enterprise goals.

These objectives were tested through external market intelligence, an Ariba Discovery RFI to identify active market participants, and benchmarking with peer utilities. A competitive RFP was launched to establish current pricing and understand market capacity.

The resulting multi-award, sub-region-based sourcing model expanded supply options by onboarding additional suppliers for earth moving, vacuum excavation, earth auger, and pre-qualifying micro-piling suppliers, increasing the number of available providers across nine service territories. Awards were predominantly made to Canadian-based suppliers, reinforcing Hydro One’s Canada First objectives and contributing to strong domestic supply chains.

The sourcing event also advanced Indigenous participation goals through the recommendation of seven Indigenous suppliers for award and projected Indigenous spend of approximately $24 million annually in earth moving, with further spend in rock drilling and vacuum excavation.

4.0 INDEPENDENT REVIEW OF SUPPLY CHAIN PRACTICES: WOOD MACKENZIE INC.

In January 2026, Hydro One engaged Wood Mackenzie Inc. (Wood Mackenzie), a leading global research and consultancy firm with deep expertise in the energy and utilities sectors, to conduct an independent review of the reasonableness of Hydro One's supply chain strategies to mitigate inflation, tariff, and demand-related cost pressures. The full report is provided as Attachment 2.0 to this Exhibit.

Wood Mackenzie benchmarked Hydro One's practices against industry best practices and a peer group of comparable North American utilities (serving between one and five million or more customers, with annual operating revenues of $2-10 billion or more, spanning electric transmission, distribution, and/or natural gas delivery) The assessment applied a standard 1-to-10 maturity scoring framework across 18 criteria in six practice areas: category management, strategic sourcing, supplier relationship management, contract management, integrated planning (SIOP), and continuous improvement. Scores were triangulated across process documentation, stakeholder interviews, and peer benchmarking.

Hydro One scored above the peer average in all six practice areas:

- Category Management: 8.0 (Peer Average: 4.5);
- Strategic Sourcing: 7.7 (Peer Average: 5.3);
- Supplier Relationship Management: 7.8 (Peer Average: 4.3);
- Contract Management: 7.8 (Peer Average: 5.4);
- SIOP (Integrated Planning): 8.0 (Peer Average: 4.3); and,
- Continuous Improvement: 8.0 (Peer Average: 5.0).

Wood Mackenzie concluded that Hydro One has established robust practices across sourcing, contracting, and supplier management that support cost control and supply assurance under current market conditions. Hydro One's overall supply chain maturity is high relative to peer North American utilities. The review found the cost pressures Hydro One has faced during the current rate period reflect broader market forces rather than

deficiencies in its procurement practices. The full methodology, market context, and detailed findings are set out in the report at Attachment 2.0 to this Exhibit.

More information on the cost pressures experienced by Hydro One, can be found in SPF Section 1.8 – Managing Market Cost Pressures.

5.0 ATTACHMENTS

Attachment	Description
1	Supply Chain Policy
2	Wood Mackenzie Supply Chain Practices Review
3	Procurement – Signing Authority Levels

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Filed: 2026-10-07
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Exhibit E-5-1
Attachment 1
Page 1 of 3

Supply Chain Policy

Purpose and Scope

The primary purpose of the Supply Chain Policy is to communicate and reinforce desired values and expectations of the supply chain activities of Hydro One Limited, its subsidiaries and the affiliates it controls (referred to in this document as 'Hydro One' or the 'Corporation').

Revision Statement

This document has been reviewed and approved to recognize our principle of sourcing materials and services with consideration to Indigenous and Canadian businesses (under the Principles section) and corrected the name of HODS SP0312 (under Section 3.0 References).

Principles

Supply Chain will:

- Acquire materials and services through a process that drives value for money, transparency to its internal customers, and builds mutually valuable relationships with key suppliers.
- Ensure the right materials and services are delivered to the right place at the right time in a cost effective manner.
- Source materials and services with consideration to Indigenous and Canadian businesses, health, safety and the environment and corporate social responsibility.
- Promote business and workforce development for Indigenous Businesses.
- Achieve operational excellence through continuous improvement in collaboration with Supply Chain's Customers and Suppliers.
- Manage its outsourcing partner to align with these principles.

Contents

1.0 Requirements
2.0 Definitions
3.0 References
4.0 Document Management
5.0 Appendices

1.0 Requirements

The key requirements of each Supply Chain function are as follows:

Strategy and Oversight:

- Provide a strategic, cost effective, data driven and analytical planning approach to Supply Chain processes.
- Direct continuous improvement initiatives to achieve operational excellence and cost effectiveness.

- Ensure an effective governance process is in place to manage change.

Sourcing:

- Develop and execute a strategic procurement plan to identify materials and services needed to meet business requirements at the best value for money.
- Employ a mix of procurement processes, including sole source, direct negotiation, and bidding processes that provide the best business outcome.
- Identify and attract qualified suppliers that provide quality products and services
- Provide opportunity for increased Indigenous Business participation in the provision of products and services.

Purchasing:

- Process Purchase Requisitions on a timely basis to ensure that customers' needs are met.
- Promote improved requisitioning through effectively documented processes and education.

Inventory Management:

- Align to the Inventory Policy (SP0732).
- Manage inventory at optimal levels and locations to satisfy operations.
- Monitor and control the accuracy of inventory data.
- Re-deploy, return or dispose of material to maximize cost savings considering environmental impact.

Logistics:

- Determine the most efficient and economical method to store and distribute materials from Suppliers to Customers.
- Facilitate the movement of returnable containers to Suppliers.

Accounts Payable:

- Remit authorized and timely payments to Suppliers in accordance with the terms and conditions of the respective contracts.
- Capture payments accurately and completely in Hydro One systems and ensure accurate account distributions.

Customer Service:

- Providing Source-to-Pay support for all internal customers
- Delivering value to all its internal customer and dedicated to providing excellent customer service.

Productivity Savings:

- Leverage purchasing power across internal organizations and strategic sourcing events to obtain competitive prices and negotiate significant cost savings

Supplier Performance Management & Governance:

- Negotiating terms and contractual language that mitigate risks and ensures Hydro One's interests are protected.
- Ensuring Suppliers meet financial, health & safety, and insurance requirements.
- Providing supplier performance management to ensure Suppliers are fulfilling their contractual commitments to Hydro One.

Data Management

- Utilize business applications, information management methods, and data management tools to implement procedures and an infrastructure to support the integration and shared use of accurate,

timely, consistent and complete Supply Chain Master Data.

2.0 Definitions

None

3.0 References

Expenditure Authority Register

Supplier Code of Conduct

SP0829 - Code of Business Conduct

SP0849 - Corporate Disclosure Policy

SP0732 - Inventory Policy

SP0733 - Inventory Procedure

SP1374 - Indigenous Procurement Procedure

SP0327 - Health, Safety and Environmental Policy

SP0312 - Contractor Safety Management

SP0826 - Sourcing Procedure

4.0 Document Management

Owner/Functional Responsibility	VP, Supply Chain, Aviation and Fleet Services
Approver	VP, Supply Chain, Aviation and Fleet Services
Approval Date	September 2025
Effective Date	September 2025
Last Reviewed Date	July 2022
Next Review Date	September 2027

5.0 Appendices

None

Wood Mackenzie

2025 Supply Chain Practices Review

Practices Review

Hydro One JRAP28

January 26, 2026

Content

January 26, 2026

EXECUTIVE SUMMARY
Executive Summary

MARKET CONTEXT
Key Drivers, Impacts, and Implications

PRACTICES REVIEW
Methodology, Industry Best Practices, Comparison to Industry, Key Findings, Next Steps

APPENDIX
Market Context Support

Wood Mackenzie

Executive Summary

Purpose Statement: Evaluate the reasonableness of Hydro One's supply chain strategies to mitigate inflation, tariff, and demand-related cost pressures by benchmarking against industry best practices and peer utilities.

MARKET CONTEXT:

- **Demand growth:** Rapid expansion of data centers and electrification projects is increasing competition for critical grid materials
- **Supply constraints:** Persistent global shortages of electrical equipment are prolonging lead times and driving price adjustments
- **Cost pressures:** Elevated material and labor costs continue due to macroeconomic conditions and limited manufacturing capacity

KEY FINDINGS:

- Hydro One demonstrates **strong governance** and **disciplined sourcing practices** under volatile market conditions
- **Indexed pricing mechanisms** and a **diversified supply base** have aligned with best practices to effectively manage price increase requests
- **Procurement and engineering collaboration** supports proactive planning and operational stability
- **Sourcing plans** are tightly **aligned** with capital investments and capacity needs

HYDRO ONE'S MATURITY VS. INDUSTRY:

- Overall supply chain **maturity is high**, with **strong performance** across governance, sourcing, and supplier management
- Procurement practices are structured, data-driven, and **generally aligned with best practices across peer utilities**
- Indexed price adjustment mechanisms reflect **cost management maturity**

Market Context

Key Drivers Behind Rising Costs: Overview

The following provides an outside-in view of forces and key drivers behind rising utility costs, illustrating how broader market and industry pressures are influencing utility strategies and reshaping procurement and planning decisions.

Global Forces

- Shifting **trade policies** and **tariffs**
- **Geopolitical instability** disrupting global supply chains
- Climate and **energy transition policies** driving competition for resources

Economic Forces

- **Inflation** raising material and project costs
- Higher **interest rates** increasing borrowing costs
- **Currency fluctuations** impacting import prices

Market Forces

- **Rising costs** for steel, copper, aluminum, and semiconductors
- **Volatile** transportation and energy **prices**
- **Supplier concentration** amplifying exposure to shocks

Industry Forces

- Skilled **labor shortages** in equipment manufacturing
- **Limited capacity** and long **lead times**
- Manufacturing **backlogs** and supplier **bottlenecks**

T&D Utility-Specific Forces

- **Electrification, population growth,** and **data center development** are increasing demand, alongside re-shoring and near-shoring of manufacturing
- **Modernization** of aging infrastructure
- Regional load growth **tightening equipment competition**

Source: Wood Mackenzie 2025 Q2 & Q3 Market Reports, Wood Mackenzie Making the Connection – Webinar Series (2025)

Operational and Financial Impacts: “So What?”

Utilities are navigating higher equipment costs, longer lead times, and supply chain risks, forcing earlier procurement, inflating capital budgets, and delaying infrastructure upgrades.

Global Forces
Trade, Tariffs, and Geopolitical Risks

IMPACT

- Geopolitical tensions and shifting trade policies are increasing exposure to tariff-related costs and supply disruptions
- Dependence on international suppliers reduces flexibility and resilience

OUTCOME

- **Tariff-driven increases**: New trade policies are increasing the cost of imported components and materials

Economic Forces
Inflation, Interest Rates, and Currency Fluctuations

IMPACT

- Inflation and interest rate volatility raise the cost of capital, equipment, and materials
- Currency fluctuations increase the cost of imported goods and complicate budgeting

OUTCOME

- **Elevated input and financing costs:** Increase total project budgets and reduce affordability of infrastructure upgrades
- **Exposure to import price volatility:** Leads to higher procurement risk and potential rate pressure on customers

Market Forces
Input Cost Volatility and Supplier Concentration

IMPACT

- Volatile prices for key materials and limited supplier availability reduce procurement flexibility
- Longer and less predictable lead times complicate project scheduling

OUTCOME

- **Budget overruns**: Rising material and labor costs are pushing actual spend beyond planned budgets

Industry Forces
Manufacturing and Labor Constraints

IMPACT

- Construction labor shortages are delaying project timelines and increasing costs for field work and installation
- Manufacturing labor shortages are reducing production capacity and contributing to equipment shortages across the supply chain
- Even with new facility investments, production capacity is not keeping pace with demand, prolonging equipment shortages

OUTCOME

- **Labor cost inflation**: Scarcity of skilled workers is driving up wages and contractor rates
- **Limited manufacturing and extended lead times**: Constrained capacity leads to higher unit costs due to reduced economies of scale and prolonged project timelines, which increase holding costs

T&D Specific Forces
Demand and Infrastructure Expansion

IMPACT

- Rising infrastructure demand from electrification, population growth, data centers, and EV adoption is accelerating grid expansion and T&D needs
- Urgent needs to modernize aging infrastructure and supply constraints are compressing planning cycles, forcing organizations to make decisions with limited visibility into future pricing and availability

OUTCOME

- **Higher capital spending:** Utilities are increasing investment in T&D infrastructure to meet growing capacity and reliability requirements
- **Increased price exposure:** Limited flexibility to time purchases raises average procurement costs and exposure to inflation- or demand-driven price adjustments

Source: Wood Mackenzie 2025 Q2, Q3, & Q4 Market Reports, Wood Mackenzie Making the Connection – Webinar Series (2025)

Implications: “Now What”

Given the potential impacts, T&D utilities must now consider how these forces and drivers translate into actionable priorities.

Force Category & Key Drivers	Implications for T&D Utilities (Alignment to Best Practices)
Global Forces Trade, Tariffs, and Geopolitical Risks	• Exposure to shifting tariffs and global supply disruptions reinforces the need to **diversify** and **regionalize supplier networks** • Increased delivery risk demands **enhanced visibility** into critical suppliers and categories
Economic Forces Inflation, Interest Rates, and Currency Fluctuations	• Persistent inflation and cost volatility highlight the need for robust **cost modeling** and **forecasting** • Rising borrowing and import costs reinforce the need for **indexed pricing** and **pricing adjustments** to provide transparency and track market movements
Market Forces Input Cost Volatility and Supplier Concentration	• Volatile material and transport costs underscore the importance of **multi-year sourcing strategies** and **long-term contracts** that establish strong and collaborative vendor relationships • Concentrated supply bases reinforce the need to **expand qualified vendors** and **competitive benchmarking**
Industry Forces Manufacturing and Labor Constraints	• Persistent manufacturing labor shortages and long lead times increase the need for **early supplier engagement** and **production alignment** • Manufacturing bottlenecks highlight the value of **supplier collaboration** and **value engineering** to secure capacity
T&D Utility-Specific Forces Demand and Infrastructure Expansion	• Accelerating electrification and grid modernization reinforces the need for **integrated procurement** and **capital planning** • Growing infrastructure demands strengthen the case for formal **governance** and **cross-functional coordination**

Practices Review

Methodology

The assessment followed a structured, evidence-based approach combining process review, interviews, and benchmarking to evaluate Hydro One's mitigation strategies for inflationary pressures against best practices.

	Collect and Analyze Process Support	Interview Supply Chain Stakeholders	Compare to Industry Best Practices	Assess Maturity Level
Purpose	Build a **fact base** on Hydro One's sourcing, contracting, and supplier management practices	Validate findings and **capture operational perspectives** on mitigation practices from key stakeholders	**Assess** Hydro One's supply chain practices against **peer utilities and leading industry benchmarks**	**Determine level of supply chain maturity** and present findings in a format that supports defensibility
Key Activities	• **Gather process support** including bid events, sourcing plans, category strategies, contract structures, and spend dashboards • **Analyze historical procurement actions** to assess inflation, demand, and tariff pressures and mitigation strategies • **Map cost drivers** and **contract terms** to identify potential exposure to market or tariff risk • **Evaluate records** for consistency, coverage, and linkage to cost mitigation objectives	• **Conduct structured interviews** with leaders and subject matter experts in Supply Chain • **Confirm** the **accuracy** and completeness of the data collected • **Gather qualitative insights** on sourcing strategy, supplier management, and contract execution • **Assess** how Supply Chain collaborates with business units and during sourcing and cost recovery activities • **Identify risk mitigation tactics** and challenges	• **Develop a benchmark inventory** of industry practices across six dimensions • **Review external benchmarks**, industry studies, and peer utility practices related to cost mitigation and sourcing resilience • **Compare Hydro One's approaches to peers** and leading practices for mitigating inflation and cost volatility • **Summarize comparative insights** to inform maturity scoring	• **Apply a maturity framework** to evaluate practice depth, consistency, and effectiveness • **Score Hydro One's performance** using both qualitative and quantitative indicators • **Identify and prioritize improvement areas** based on maturity gaps, and potential impact

Industry Best Practices for Mitigating Inflation Pressures

The following categories were evaluated to benchmark Hydro One's mitigation practices against leading industry approaches for managing inflation and cost volatility.

Category	Criteria	Best Practice Summary	Expected Outcome
Category Management	• Spend Visibility and Categorization • Cost Modeling and Prediction • Procurement–Business Partnership • Specification Standardization	Build full visibility into spending and cost drivers, while standardizing materials and specifications	Supports proactive planning, earlier issue identification, more informed negotiations, and reduces price variability
Strategic Sourcing	• Risk Management and Purchase Timing • Negotiation Frequency • Diverse and Broad Supplier Base	Manage sourcing risk through hedging, diversified supplier networks, and agile purchasing strategies	Strengthens supply continuity, mitigates exposure to market volatility, and improves ability to capture market opportunities
Supplier Relationship Management (SRM)	• Supplier Segmentation • Supplier Engagement and Collaboration • Value Engineering • Supplier Performance Management	Develop segmented supplier strategies that enhance collaboration and performance	Improves access to critical materials and increases resilience during market disruptions
Contract Management	• Price Management and Escalation • Term Length • Exit Clauses • Auditing	Use flexible contract structures and pricing adjustments	Balances cost stability with market responsiveness, increases transparency, and supports more predictable long-term commercial performance
Sales, Inventory, Operations, and Planning	• Integrated Planning • Governance	Align demand forecasting, inventory planning, and procurement	Reduces reactive buying, improves availability of critical materials, and strengthens cross-functional coordination
Continuous Improvement	• Cross-functional Continuous Improvement Projects	Foster a continuous improvement culture supported by data-driven decision-making	Drives cost optimization, enhances process efficiency, and supports long-term operational resilience

Peer Utility Benchmarking Group Overview

To provide meaningful insights, Hydro One's performance was benchmarked against a select group of North American utilities (including those in the US and Canada) comparable in scale, revenue, and complexity.

PEER GROUP CHARACTERISTICS

- **Scale:** Utilities serving 1–5+ million customers across residential, commercial, and industrial segments
- **Revenue:** Annual operating revenues between $2–10+ billion, spanning investor-owned, municipal, and public utilities
- **Service Diversity:** Operations include electric transmission, distribution, and/or natural gas delivery, supported by large-scale capital programs
- **Operational Complexity:** Peers manage advanced grids, extensive networks, and mature supply chain and energy transition programs

PEER SELECTION RATIONALE

- **Comparable Customer Base:** Large, diverse service populations similar to Hydro One
- **Financial Scale:** Revenue and cost structures aligned with Hydro One's operating profile
- **Best Practice Leadership:** Recognized innovators in project execution, procurement, and resource management

DATA HANDLING AND CONFIDENTIALITY

- All benchmarking data was aggregated and anonymized; no proprietary or utility-specific information is disclosed. Comparative results are presented as ranges or averages to preserve confidentiality

Our Benchmarking Standards

Wood Mackenzie's confidentiality terms with clients drive **strict internal benchmarking policies and standards**, warranting analyses are conducted consistently, comparably, and objectively across utilities.

Confidential and Non-Attributable

- Wood Mackenzie never discloses the **names or number of benchmarking sources**
- All data is **aggregated and anonymized**, ensuring no utility-specific information can be identified
- Company names, proprietary specifications, raw data points, and **regional or participant-specific data breakdowns are never disclosed,** to prohibit any attempt to infer or triangulate participant identities

Rigorous Peer Selection

- Peer groups are defined using **Wood Mackenzie's internal benchmarking standards**, considering utility size, spend profile, asset mix, and operating model
- Results reflect **market-derived ranges** intended solely for comparative purposes

Standardized Methodology

- Benchmarks are built from **consistent data definitions** to maintain comparability and normalization practices
- Analysis follows established Wood Mackenzie protocols for **data normalization, maturity scoring, and weighting**

Independent and Objective

- All benchmarking assessments are performed under **strict internal quality controls**, including multiple QA/QC steps
- Results are presented **objectively and without influence** from participants or external review

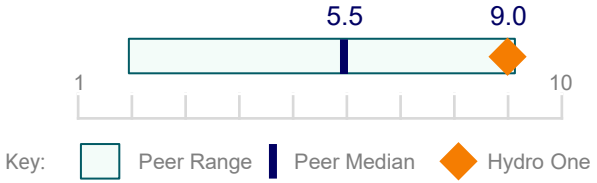
Maturity Scoring Framework

A framework was used to evaluate Hydro One's maturity against leading North American utilities and industry best practices, using a standardized 1–10 scoring scale validated through multiple evidence sources.

CRITERIA SCORING METHODOLOGY:

- **18 criteria were scored individually on a 1–10** scale aligned to industry best practices and maturity
- **Peer Range:** Represents the spread of scores across benchmark utilities
- **Example: Spend Visibility and Categorization**
  - Peer scores ranged from 2 to 9, with a median of 5.5
  - Hydro One scored 9, exceeding the peer median

Spend Visibility and Categorization



CATEGORY SCORING METHODOLOGY:

- **Category scores represent the average of the criteria scores in the category**
  - Example: The score for ***Category Management*** is the average of the four criteria scores for 1) Spend Visibility and Categorization, 2) Cost Modeling and Prediction, 3) Partnership between Procurement and BUs, and 4) Specification Standardization **[8.3 = (9+8+8+8)/4]**
- **Peer Range:** Represents the minimum to maximum of the peer group averages
- **Example:** The Category Management scores show an average score of 4.5, with category averages ranging from 2.5 – 6

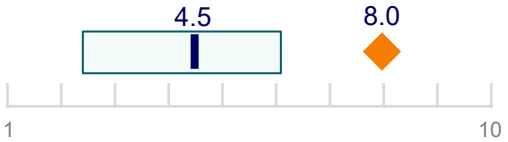
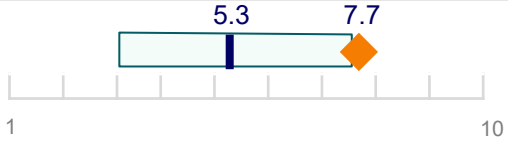
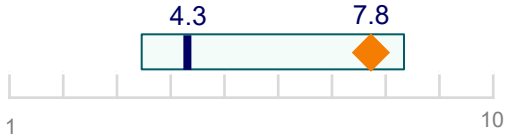
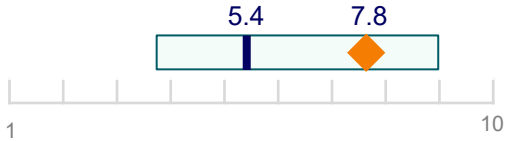
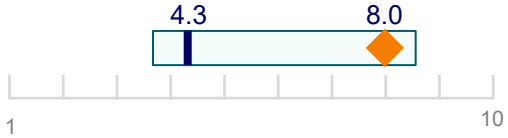
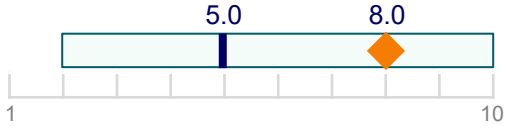
Category Management

EVIDENCE TRIANGULATION:

Evidence Source	Purpose	Examples
Process Review	Validate formal processes and governance alignment to best practices	Policies, sourcing plans, contracts, bid support
Stakeholder Interviews	Confirm adoption and effectiveness of processes	Supply chain leaders, SMEs, functional owners
Peer Benchmarking	Assess maturity relative to peers (based on scale, revenue, and operational complexity)	North American and Canadian utilities

Comparison to Industry Best Practices: Overview

Hydro One's performance was evaluated against six best practice categories and industry peers.

Category	Peer Comparison	Hydro One Findings
Category Management		• Category management is supported through structured spend data, cost-analysis tools, and sourcing plans coordinated with project needs • Standardization efforts and industry collaboration reduce custom specifications, improve consistency, and present savings opportunities
Strategic Sourcing		• Sourcing integrates risk management, indexed pricing, and early capacity reservation efforts to reduce inflation exposure and lead times • Negotiations consider market information, and supplier diversification supports the continuity of supply • Sourcing approaches are reviewed as part of category planning
Supplier Relationship Management		• Supplier engagement includes structured reviews and performance monitoring • Value engineering and scorecards drive cost reduction, reliability, and continuous improvement
Contract Management		• Index-based pricing, rebates, and flexible contract terms support cost stability and adaptability • Auditing and system controls support compliance and reduce potential for unauthorized pricing
SIOP (Sales, Inventory, Ops, and Planning)		• Sourcing plans and governance align supply, demand, and investment priorities • System integration activities support the availability of data used in operational and sourcing decisions • Ongoing modernization efforts focus on improving coordination across planning functions
Continuous Improvement		• Supply Chain continues to undergo continuous improvement efforts • Current efforts focus on reducing manual work and leveraging analytics for forecasting and long-term supplier collaboration

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range (Min - Max of Peer Category Averages) | Peer Criteria Average | Hydro One Criteria Average

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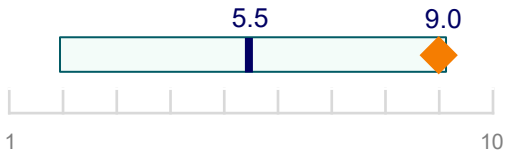
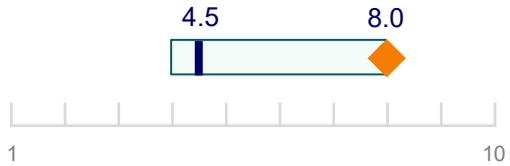
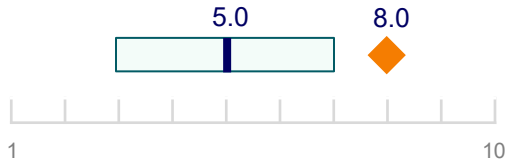
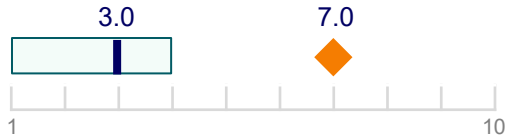
Comparison to Industry: Category Management

Category management activities reflect structured processes for spend visibility, cost analysis, cross-functional planning, and specification management that support sourcing effectiveness.

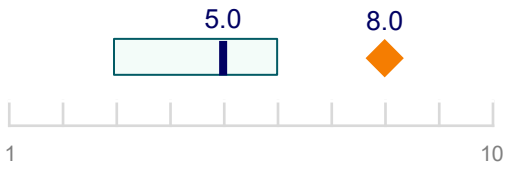
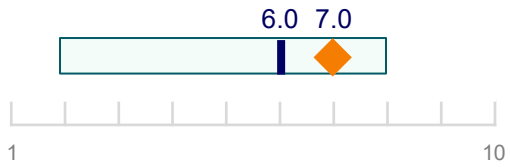
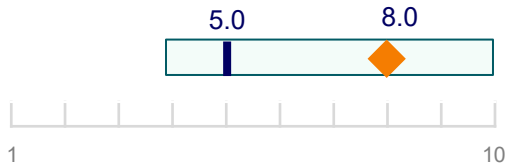
Criteria	Peer Comparison	Best Practices for Criteria	Hydro One Findings
Spend Visibility and Categorization		• Spend data is centralized and regularly analyzed • Categories are well-defined and used to guide sourcing strategy	• Spend visibility is supported through multiple data sources and analytics tools • A structured spend taxonomy aligned to UNSPSC codes is used to categorize materials and services • The annual sourcing plan links procurement activities to enterprise priorities
Cost Modeling and Prediction		• Category teams regularly use cost models and industry trends to forecast, negotiate, and build custom models • Software tools are fully integrated	• Cost modeling incorporates historical spend and available market data • Cost driver analysis is used in evaluating select material categories • Forecasting supports sourcing decisions
Partnership between Procurement and Business Units		• Procurement and business units jointly develop strategies • Collaboration is proactive, consistent, and informs decisions early	• Procurement collaborates with engineering, construction, and technical functions to co-develop sourcing plans • Five-year investment plan to prioritize material needs and secure capacity early
Specification Standardization		• Procurement successfully builds business cases to address standardization efforts at scale • Procurement partners with Engineering to prioritize and pursue modular designs • Bespoke SKUs are phased out, following 80/20 rule in terms of impact by spend and quantities	• Specifications are centralized where applicable • Hydro One intends to collaborate with Electricity Canada to align specifications with peer utilities to leverage bulk procurement this this alignment • Sourcing events are structured to follow category strategies rather than unique, bespoke processes

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range | Peer Median | Hydro One

Comparison to Industry: Strategic Sourcing

Hydro One demonstrates disciplined sourcing practices through indexed pricing and supplier diversity, positioning well against peers in risk management and market responsiveness.

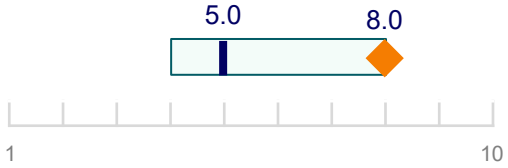
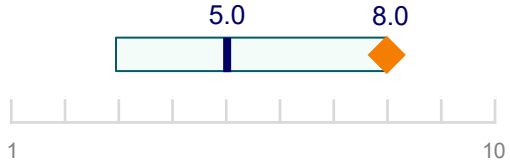
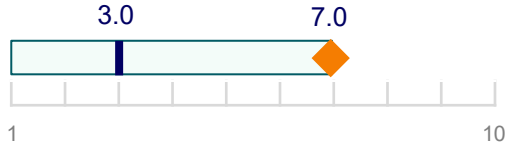
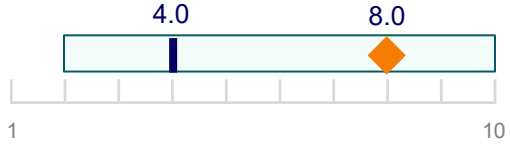
Criteria	Peer Comparison	Best Practices for Criteria	Hydro One Findings
Risk Management and Purchase Timing		• Integrated risk and timing strategies tailored by category • Procurement uses risk registers and advanced analytics to act on market forecasts, optimizing purchase timing and executing inventory drawdown or stockpiling strategies aligned with business needs	• Risk management integrates indexed pricing and pre-ordering programs to mitigate supply delays • Indexed commodity pricing helps to reduce the risk of misalignment with market conditions
Frequency of Negotiation Efforts		• Negotiations follow a fact-based process, are driven by benchmarking insights, market trends, and contract risk profiles • Negotiations are used consistently across categories • Negotiations are planned and used proactively • Negotiations may have multiple cycles depending on business cases, criticality, and complexity of situation	• Negotiation frequency is informed by commodity volatility, contract expiry, and performance trends • RFPs demonstrate flexibility and market responsiveness • Cadence varies by category
Diverse and Broad Supply Base		• Supplier base is strategically diversified at the category level • Procurement actively benchmarks against industry norms and mitigates risks in critical areas through proactive supplier management	• Category strategies intentionally diversify supply across regions and vendors • There is more than one approved qualified supplier per category • “Buy Canada” procurement practices prioritize domestic production

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range | Peer Median | Hydro One

Comparison to Industry: Supplier Relationship Mgmt.

Hydro One demonstrates mature Supplier Relationship management capabilities through structured supplier reviews and strategic segmentation.

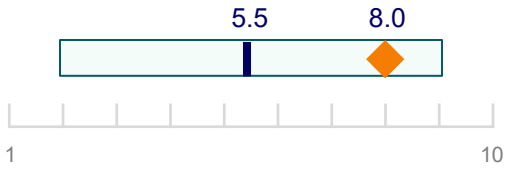
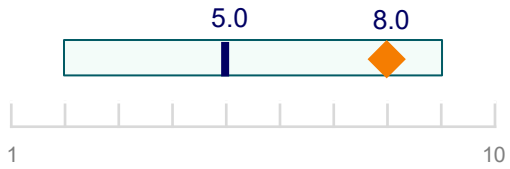
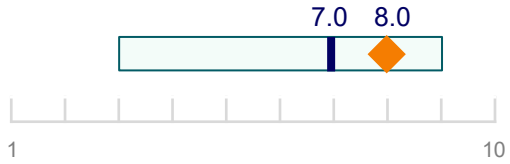
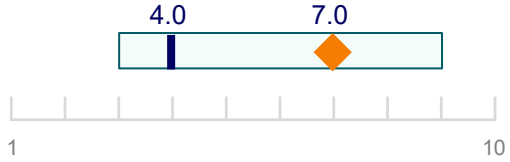
Criteria	Peer Comparison	Best Practices for Criteria	Hydro One Findings
Supplier Segmentation		• Suppliers segmented by value, performance, and risk • Category spend comprised of multiple qualified suppliers per category • Segmentation directly informs sourcing strategy, relationship management, and risk mitigation planning	• Suppliers are segmented into strategic and operational partners identified based on spend, criticality, and ROI • Strategic partners receive executive reviews • Operational partners have annual continuous improvement reviews • Multiple qualified suppliers per category
Supplier Engagement and Collaboration		• Strategic suppliers participate in structured reviews focused on cost transparency and joint problem-solving • Utilities and suppliers share forecasts and cost data to strengthen long-term cost stability and reliability • Collaboration extends to identifying innovation and efficiency opportunities across the value chain	• Executive-level Business Review Meetings (BRMs) are held with executives, emphasizing transparency, innovation, and problem-solving for critical categories • Operational BRMs focus on performance and continuous improvement
Value Engineering		• Frequent reviews are built into project planning • Regularly work with key suppliers jointly to improve cost, reliability, and efficiency across major categories	• Value engineering reviews occur before BRMs, focusing on cost efficiency, safety, and reliability improvements
Supplier Performance Management		• Robust, data-driven supplier performance management systems/processes are in place for all strategic suppliers • KPIs include safety, reliability, cost, and innovation metrics • Results drive corrective actions and future sourcing decisions	• Scorecards have unique questions for strategic and operational suppliers, combining KPIs with soft measures (e.g., responsiveness) • Supply Chain fills quantitative data; business units provide qualitative feedback

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range | Peer Median | Hydro One

Comparison to Industry: Contract Management

Hydro One's contract management approach reflects defined pricing, terms, and auditing practices that support transparency and long-term commercial stability.

Criteria	Peer Comparison	Best Practices for Criteria	Hydro One Findings
Price Management and Escalation		• All major contracts include structured price adjustment mechanisms (e.g., inflation-linked, performance-based, or benchmark-indexed) • Price performance is reviewed regularly against KPIs and industry benchmarks and tied to supplier scorecards	• Index-based price adjustment formulas are used in select contracts, with provisions referencing relevant commodity or market indexes • Suppliers are asked to provide justification for proposed pricing changes
Term Length		• Multi-year contracts are strategically structured (e.g., capped-pricing clauses, index-based formula pricing) to balance long-term cost stability with flexibility to respond to market and operational changes	• Standard three-year terms with optional extensions are common • Off-cycle reviews occur for key suppliers to support flexibility and continuity
Exit Clauses		• Exit and pricing adjustments are standard across all strategic contracts • Provisions are actively reviewed and tested during performance under changing conditions • Use of liquidated damages or fees at risk enforces and encourages quality performance of work	• Contracts include provisions such as termination for convenience, termination for breach, suspension of work • Liquidated damages and fees at risk are used to enforce and encourage quality performance of work
Auditing		• Comprehensive, scheduled audit program covering all strategic and regulated supplier contracts • Findings are documented, corrective actions tracked, and insights inform both supplier scorecards and sourcing strategies	• Use of SAP three-way match supports contract compliance • Annual audits check cost accuracy and supplier adherence to pricing-related expectations

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range | Peer Median | Hydro One

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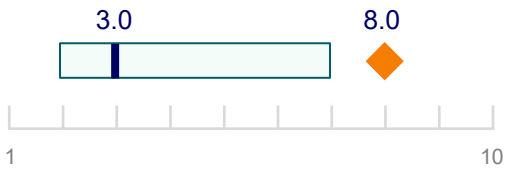
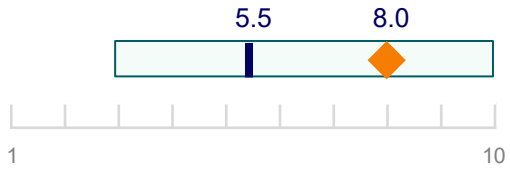
Comparison to Industry: SIOP

Hydro One's Sales, Inventory, Operations, and Planning (SIOP) maturity compares favorably to peers, with governance and structured planning cycles supporting integrated sourcing and investment alignment.

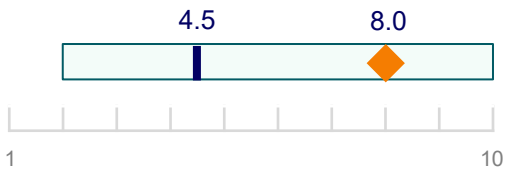
Criteria	Peer Comparison	Best Practices for Criteria	Hydro One Findings
Integrated Planning		• Fully integrated SIOP process with shared systems and Key Performance Indicators • Demand, supply, capacity, and financial plans are aligned regularly • Scenario analysis used to optimize total cost of ownership and inventory risk	• Hydro One maintains a sourcing outlook, refreshed regularly • Forecasts link to investment plans and supplier capacity agreements
Governance		• Formal cross-functional governance structure with defined roles, approval thresholds, and recurring review cadence • Sourcing and supply chain decisions are documented and aligned with organizational goals	• The annual sourcing plan defines priorities and allocation • Governance includes cross-functional reviews with sourcing leadership, Engineering, and Finance, among others, to improve alignment with investment, regulatory, and financial priorities

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range | Peer Median | Hydro One

Comparison to Industry: Continuous Improvement

Hydro One's continuous improvement (CI) activities are consistent with peers, supported by structured operational improvement initiatives and growing use of digital tools to sustain efficiency improvements.

Criteria	Peer Comparison	Best Practices for Criteria	Hydro One Findings
Cross-Functional CI Projects		• CI programs are embedded across the enterprise with clear roles and shared goals • Formal process exists to identify, prioritize, and track improvement initiatives across functions • Results are measured and communicated; projects target both operational reliability and cost efficiency	• The supply chain organization continues to undergo continuous improvement efforts • Strong cross-functional collaboration integrating category, operations, and planning/project teams • Increasing automation and analytics adoption for forecasting, spend analysis, and process optimization

Reference: Peer Utility Benchmarking Group Overview (Appendix)

Peer Range | Peer Median | Hydro One

Key Takeaways

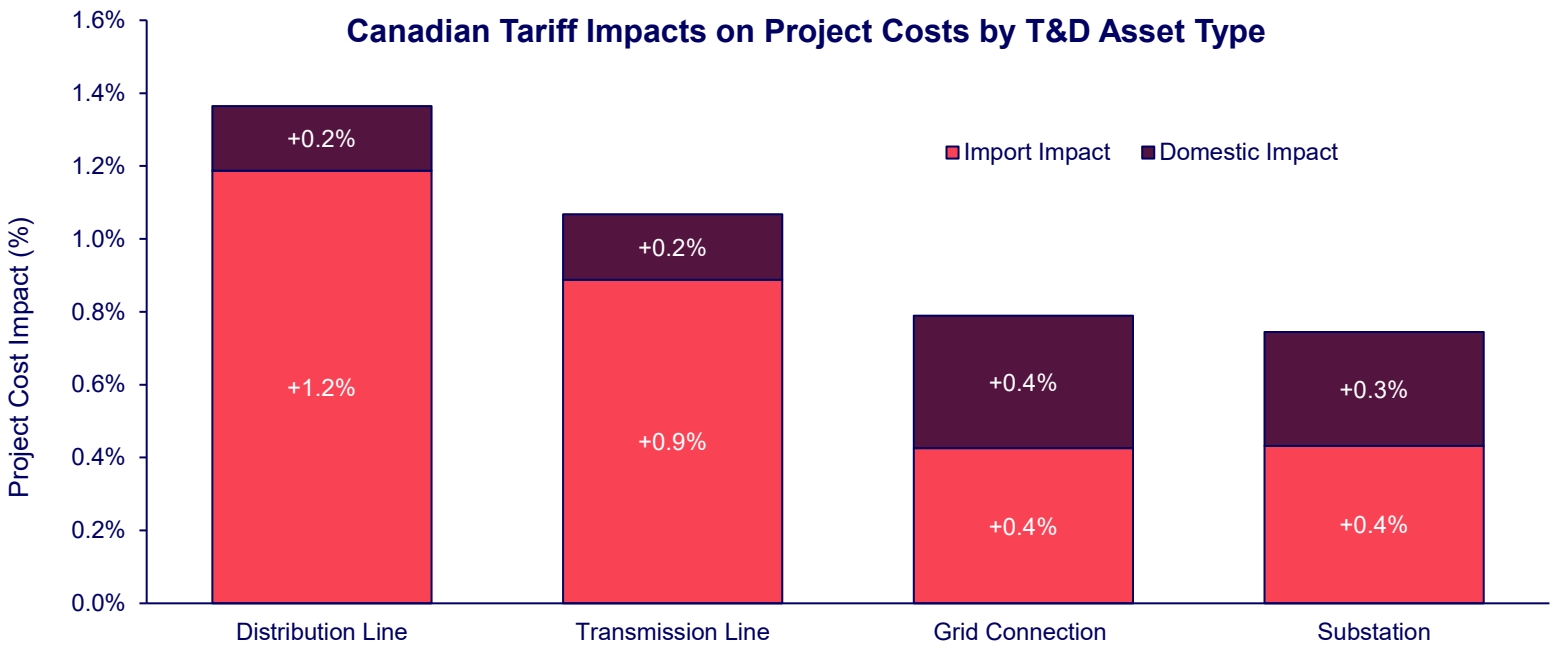
Findings demonstrate that Hydro One's procurement and supply chain practices reflect **strong governance and cost efficiency under inflationary market conditions**.

KEY FINDINGS:	HYDRO ONE VS. INDUSTRY BEST PRACTICES:
• Hydro One has established **robust, transparent practices** across sourcing, contracting, and supplier management, supporting cost control and supply assurance under inflationary and tariff pressures	• Hydro One's maturity levels are **high compared to peer North American utilities**, particularly in supplier governance, contract management, supplier management, and sourcing strategy
• **Governance and sourcing discipline**, including indexed pricing and multi-supplier strategies, have helped minimize exposure to price adjustments and supply disruption	• **Category management and supplier collaboration** are advanced, aligning with utilities recognized for proactive market and cost management
• **Structured supplier engagement and segmentation** demonstrate active management of market risk and continuity in critical categories	• Hydro One's **procurement** and **risk management** practices reflect a structured and data-driven approach

Appendix

Key Drivers Behind Rising Costs: Global Forces

New tariff policies are one lens into the broader global forces reshaping Canadian utility costs, alongside geopolitical tensions and climate policy commitments.



The chart illustrates the effects of Canadian tariffs on both finished equipment imports and the underlying commodities used in domestic equipment manufacturing. This analysis estimates the potential impacts on total project costs for Canadian Utilities based on the following:

- **Import impact:** Tariffs on U.S. imports and pass-through costs from U.S. manufacturing
- **Domestic impact:** Higher costs for Canadian-made goods due to steel, aluminum, and commodity tariffs

Source: Wood Mackenzie

KEY INSIGHTS

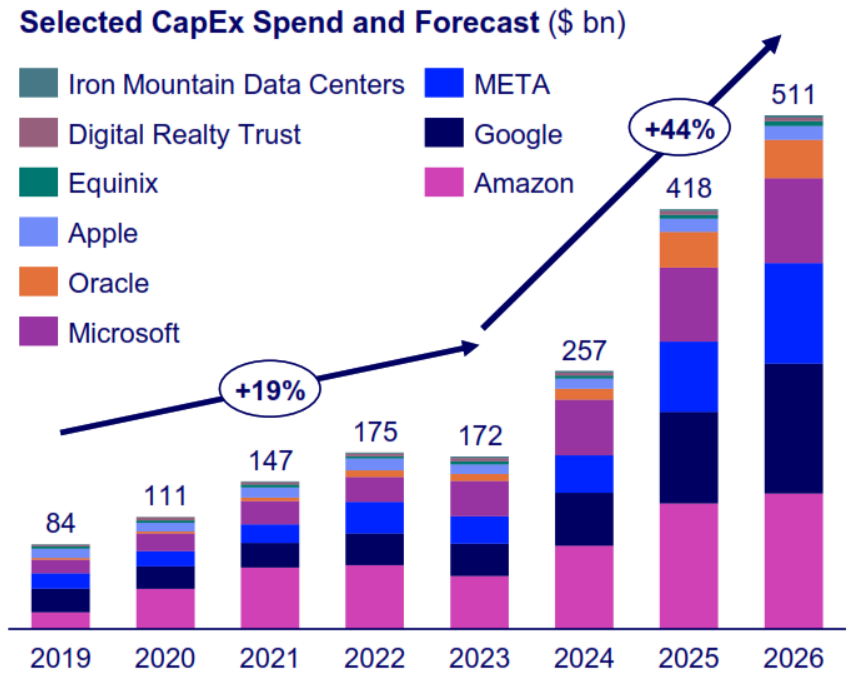
- As of March 13, 2025, Canada imposed 25 % reciprocal tariffs on U.S. steel and aluminum imports (and select other goods) in response to U.S. metal tariffs
- T&D assets are comprised of imported components and metal-intensive structures to varying degrees; creating pricing impacts that vary dependent on the equipment/material required
- Overall tariff impacts have resulted in a shift towards US manufacturing (where available), increasing market pricing that reflects the cost to manufacture products in the US; resulting new prices are passed through to Canadian buyers

Key Drivers Behind Rising Costs: Industry Forces

Manufacturing constraints and supplier bottlenecks have met rising demand for critical grid equipment, especially hyperscalers, impacting substation builds and system expansion projects.

Market Surplus or Deficit by T&D Equipment

Equipment Type	2020	2025	2030
Pad Mount 1 Phs Transformer	+16%	-4%	-3%
Pad Mount 3 Phs Transformer	-1%	-11%	-20%
Pole Mount Transformer	-2%	-8%	-2%
Power Transformer	-1%	-48%	-4%
Circuit Breakers	+10%	-45%	-25%
MV Switchgear	0%	-19%	-2%
HV Switchgear	0%	-27%	-14%
Wire & Cable	+3%	-2%	-2%



- **Key T&D equipment types are falling from a slight market surplus in 2020 to a significant shortage in 2025** (and are expected to remain in a shortage throughout 2030
- **Increased demand** from data centers, commercial facilities, and electrification projects is intensifying pressure on transformer and switchgear supply chains already operating at capacity

- The rate at which industry demand for electric T&D equipment is increasing is not being met by announced manufacturing expansions
- Supply shortages impact lead times. **Lead times for Generator Step-Up transformers increased 18% and for pole-mount transformers 14**% between Q3 and Q4 of 2024

Source: Wood Mackenzie, hyperscaler data compiled from corporate annual reports.

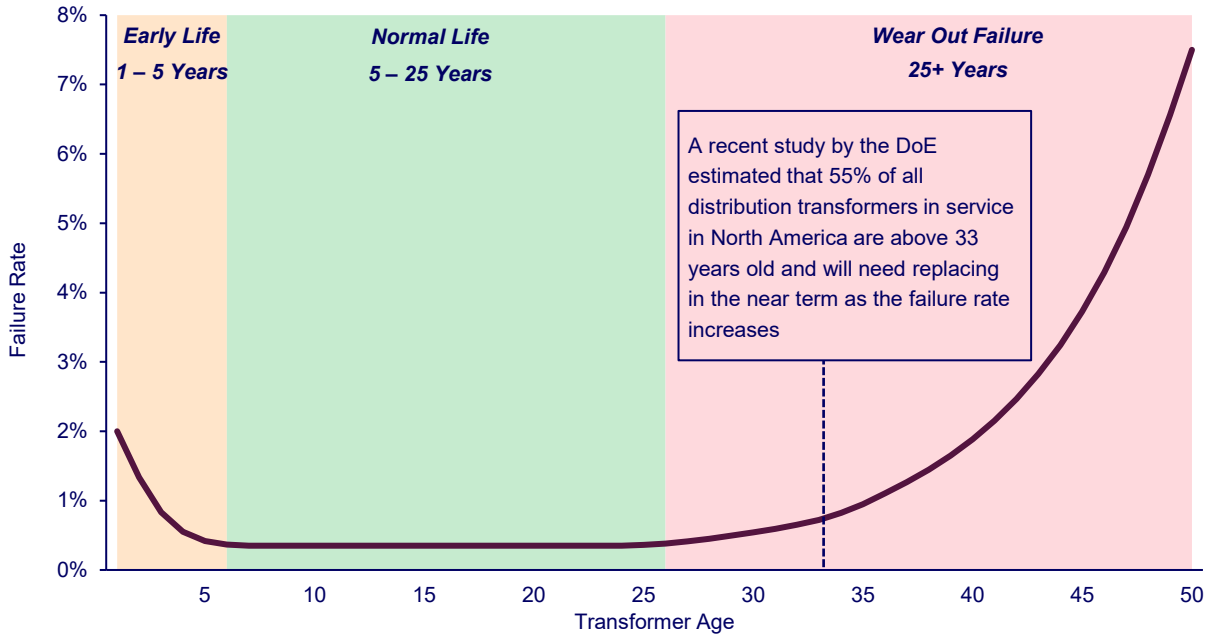
Wood Mackenzie

**Percentage are relative to supply estimates. Negative values indicate a market deficit. A value of -10% means demand is 10% above supply.*

Key Drivers Behind Rising Costs: T&D Forces

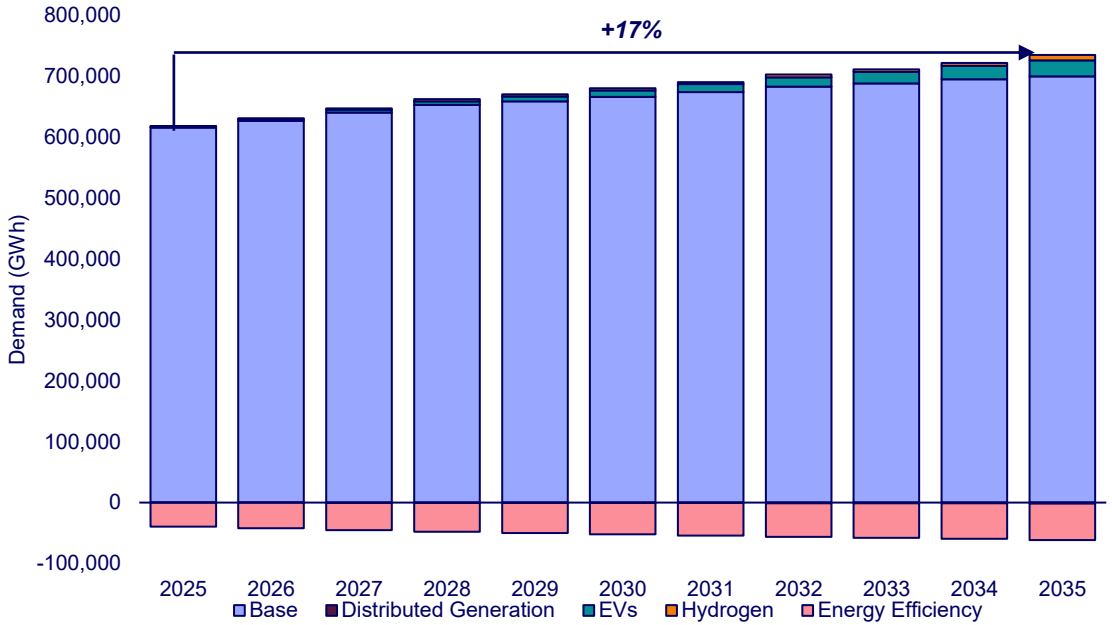
Aging infrastructure combined with electrification and load growth is raising demand for transformers, switchgear and grid-connection assets, reshaping investment timing and procurement risk.

Distribution Transformer Failure Rate



- Aging T&D assets are a growing driver of replacement demand as equipment nears the end of life and failure rates accelerate
- Failure rates increase with age, rising from approx. **0.75% at 33 years** to **1.9% at 40 years**
- Higher electrical loads and thermal stress are expected to further accelerate aging and increase equipment failure risk

Canada's Projected Electricity Demand: 2025 - 2035



- **Canada's electricity demand is projected to increase by 17% by 2035**
- After 50 years of stability, grid modernization, electrification, and population growth (Ontario's population grew by 3.2% from July 2023 to July 2024) are driving a sharp rise in demand

Source: Wood Mackenzie, Statistics Canada

Wood Mackenzie

Wood Mackenzie

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Procurement - Signing Authority Levels

Transaction	Description	Approver	Authority Limit
Purchase Orders and Procurement Contracts	Procurement contracts and purchases orders (POs) related to approved purchase requisitions. Outline agreements (OAs) and separately executed contracts that set terms and conditions of vendors.	VP, Supply Chain & Fleet Services	Unlimited and can be further delegated by VP, Supply Chain & Fleet Services up to a maximum of $20M
		Director, Strategic Sourcing Director, Supplier Relationship Management	Up to $20M
		Manager, Sourcing Operations Manager, Contract Management Senior Sourcing Category Lead - Procurement Operations only	Up to $10M
		Sourcing Category Manager Manager, Operating Services	Up to $3M
		Senior Sourcing Category Lead Sourcing Category Lead Procurement Ops Functional Lead Individual Business Analyst Buyer Contract Management Buyer	Up to $1M
	Authority to approve single or sole source purchasing transactions, including but not limited to committing the company and contracting with third parties.	EVP, Chief Financial & Regulatory Officer	Up to $50M
		VP, Supply Chain & Fleet Services	Up to $35M and can be further delegated by VP, Supply Chain & Fleet Services up to a maximum of $35M
		Director, Strategic Sourcing	Up to $10M and cannot be further delegated
		Manager, Sourcing Operations	Up to $1.5M and cannot be further delegated

COMPENSATION

1.0 INTRODUCTION AND OVERVIEW

This Exhibit discusses the compensation paid to Hydro One's workforce of represented and non-represented employees. The sections below detail the major components of total compensation offered to employees, highlighting achievements to contain or reduce compensation costs, including recent collective bargaining outcomes with union partners in the Power Worker's Union (PWU) and the Society of United Professionals (SUP).

Hydro One has continued to make progress in reducing its compensation costs relative to market, while retaining the talented and experienced workforce required to support its operations and growing investment plan. This enables the Company to continue delivering safe, reliable, and cost-effective service.

Key contributors to lowering compensation costs include amendments to pension rules, which continue to reduce pension costs, and the achievement of mutually beneficial collective bargaining outcomes with the PWU and SUP on wage increase levels, pension contribution rates, lump-sum payments, and equity grants. As 91% of Hydro One employees are represented, collective agreements are the main driver of the Company's compensation costs.

Mercer (Canada) Limited (Mercer) recently completed its updated compensation benchmarking study, which shows that Hydro One's overall compensation levels compared to peers have notably improved. The study results, encompassing both represented and management employees, show that Hydro One's overall compensation position is now only 1% above the market competitive range (i.e. +/- 5% of the P50 median), and 6% above the P50 market median. These results continue a long-term trend of improvement in Hydro One's compensation levels relative to peers. Since 2008, Hydro One has progressively and significantly reduced the gap between its compensation levels and market, moving from 17% above P50 in 2008, to 9% above P50 and 4% above the

market competitive range in 2020, and to 6% above P50 and 1% above the market competitive range in 2026.

The recent Willis Towers Watson (WTW) benchmarking study, which focusses on Management and Non-Represented employees (MGT-NR), shows that Hydro One's overall compensation position for this employee population is aligned with market median.

Hydro One's compensation is necessary to attract and retain the skilled workforce required to execute its growing investment plan and maintain the ongoing operations of the business. The Company recognizes the importance of continuing to deliver service to its customers in a cost-effective manner and remains committed to operating with market-based levels of compensation.

Actual and projected compensation costs by compensation type and employee category are provided in the attached Appendix 2-K (Attachment 1A).

The Mercer study report and WTW study report are provided in Attachments 2 and 3, respectively. Details of the Hydro One workforce mix and workforce planning process are provided in Exhibit E-06-02 Workforce Strategy.

2.0 DESCRIPTION OF HYDRO ONE'S WORKFORCE

This section provides a high-level description of Hydro One's workforce with reference to compensation programs for each category of employees.

Overall compensation costs are impacted by:

- the size of the workforce;
- the types of resources engaged (the job level and type of Full-Time Equivalent (FTE),[1] known as the workforce mix), and;

[1] Full Time Equivalent (FTE). At Hydro One, FTEs represent average monthly headcount over a 12-month period. A regular status employee who is budgeted for one year of work, represents one FTE. For casual employees, one FTE equates to 12 person months of work. For example, if one casual employee worked for six months they would account for 0.5 FTEs.

- the level and form of compensation paid to the workforce.

Hydro One's workforce is comprised of three types of employees according to their status: (i) regular, (ii) casual, and (iii) temporary. Regular employees make up 75% of the total workforce; casual employees are approximately 23% of the total workforce, and temporary employees are about 2% of the total workforce. Hydro One's workforce planning process and a more detailed discussion of the employee categories, including their functions, are provided in Exhibit E-06-02 Workforce Strategy.

2.1 REGULAR EMPLOYEES

2.1.1 REPRESENTED GROUPS

Approximately 88% of regular employees (and 91% of all employees) are represented by unions. The compensation paid to PWU and SUP employees is determined by the collective agreements which dictate base salary, pension, benefits, optional employee share ownership plan (with employer contributions), leave of absence, and overtime premiums.

Approximately 60% of regular employees (and 54% of all employees) are represented by the PWU. Employees represented by the PWU occupy roles related to technical, trades, clerical, or customer service and call centre functions under the PWU collective agreement, and perform work such as lines, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, system operations and clerical/administrative work.

Approximately 28% of regular employees (and 22% of all employees) are represented by the SUP. Employees represented by the SUP occupy roles related to technical, engineering, regulatory, communications, digital technology, financial and analytical and supervisory work. SUP-represented staff also play key roles in the oversight, analysis, and business planning of network operations, as well as protection and control work and project management.

2.1.2 MANAGEMENT AND NON-REPRESENTED EMPLOYEES (MGT-NR)

The remaining approximately 12% of the regular workforce (9% of all employees) are MGT-NR employees who are not represented by a union. The compensation and benefits package for management employees includes: (i) a market-based and segmented base pay structure; (ii) performance-based incentive pay; (iii) pension; (iv) an optional employee share ownership plan with employer enhancements; and (v) health and dental plan, paid vacation, short-term sick leave, and long-term disability benefits coverage.

MGT-NR employees primarily fill managerial roles and positions that are excluded from union representation for reasons such as confidentiality related to labour relations or legal matters. These employees lead the Company by setting strategy, overseeing operations, directing work activities, and managing risks in support of the achievement of corporate objectives.

2.2 CASUAL EMPLOYEES

Casual employees are represented by unions, mainly the PWU, or the Buildings Trade Unions (BTUs). Compensation for casual employees is governed by the relevant collective agreements, as detailed further below. The flexible terms of casual labour ensure that workers with the required skill set are hired or deployed to the necessary location for only the duration of the work assignment, and that Hydro One has no ongoing compensation obligations with respect to benefits or pension.

Casual employees are typically retained for 40 hours per week for a fixed period to execute and support construction work, supplemental maintenance work, supplemental customer service and clerical support work, or to complete an apprenticeship program.

2.2.1 PWU HIRING HALL

The PWU administers a hiring hall (PWU HH) of contingent workers governed by the PWU Collective Agreement to meet fluctuating work demands primarily in the areas of supplemental construction, maintenance, customer service and administrative/technical work. PWU HH workers receive a total wage package and are not entitled to join the Hydro

One pension or benefits programs. They are not entitled to paid vacation/statutory holidays or paid sick days and are paid a percentage in lieu. Finally, these employees are not entitled to paid notice or severance when their work ends.

2.2.2 CONSTRUCTION TRADES EMPLOYEES REPRESENTED BY BUILDING TRADES UNIONS

Construction trades employees are casual status employees that are represented by building trades unions such as the Canadian Union of Skilled Workers (CUSW), International Brotherhood of Teamsters (Teamsters), Labourers' International Union of North America (LIUNA), International Union of Operating Engineers (Operating Engineers), International Association of Bridge, Structural, Ornamental and Reinforcing Ironworkers (Ironworkers) or Carpenters Regional Council, United Brotherhood of Carpenters and Joiners of America (Carpenters). Collective agreements covering this workforce are negotiated through an employer's association, the Electrical Power Systems Construction Association (EPSCA).[2] The Building Trades Unions are made up of employees performing construction industry work for the Bulk Electric System on property owned by Ontario Power Generation Inc., Bruce Power LP and Hydro One.

These skilled trades are required to do specific work for Hydro One, however, they are casual employees and therefore there is no ongoing compensation costs for pension, and benefits obligations for any employees in the construction trades.

2.3 TEMPORARY EMPLOYEES

Temporary employees exist in the PWU, SUP and MGT-NR classifications. These employees are typically retained for 12 to 18 months, or up to two years for some MGT-NR positions. Temporary employees are often highly skilled and are hired to fill positions where the duration/extent of the work does not warrant retention of a permanent employee; often covering leaves of absence or other short-term work. The use of temporary employees provides cost flexibility by aligning labour costs directly with short-

[2] The only exception to this is CUSW, who is a building trades union; however, Hydro One negotiates directly with CUSW, rather than through the EPSCA.

term workload requirements, while avoiding long-term compensation obligations such as benefits, pension, annual increases, incentive payments, and severance.

3.0 COMPONENTS OF WORKFORCE COMPENSATION

This section discusses the components of compensation and benefits paid to Hydro One's represented and management/non-represented employee groups.

3.1 COMPONENTS OF COMPENSATION: REPRESENTED GROUPS

Compensation and terms of employment for the represented workforce are determined by collective agreements. Regular unionized employees receive a salary that is based on an hourly or weekly rate (35 or 40 hours per week), and are provided vacation, sick leave, long-term disability benefits, health and dental benefits, and other forms of paid leave. The base salary of a represented employee is typically determined by their classification and seniority. Any changes to the wage structure within collective agreements is determined through the collective bargaining process.

Approximately 76% of all Hydro One employees are represented by the PWU and SUP. The terms of the PWU and SUP collective agreements are comprehensive and complex. The terms of these agreements include:

- conditions of employment: wages, leave (vacation and sick leave etc.), pension and benefits;
- selection language: provisions relating to candidate qualifications for vacancies/job competitions;
- voluntary and involuntary separation protocols and entitlements;
- provisions pertaining to scheduling, hours of work, overtime rates; and
- a description of work jurisdiction and contracting-out provisions.

Recent results of the collective bargaining process in respect of wage rates, pension and benefits are discussed below in section 4.1.

The following sub-sections detail the share grant, Employee Share Ownership Plan (ESOP) and pension elements of the compensation plans for represented employees. Hydro One's equity-based compensation programs support the attraction and retention of the skilled workforce required to deliver the Company's investment plan. Employee ownership helps align employee and Company interests, supports workforce continuity, and contributes to the safe, reliable, and efficient delivery of services for customers. It is a meaningful component of the Hydro One rewards offering that provides competitive compensation while limiting growth in base salary and pension.

3.1.1 SHARE GRANTS

PWU and SUP-represented regular, full-time employees who were members of the pension plan as of April 1 and September 1, 2015, respectively, are eligible to receive grants of Hydro One Limited shares. These share grants were established as part of the monetary settlements negotiated following the Province's decision to proceed with the Initial Public Offering (IPO) of Hydro One Limited in 2015. In the 2015/2016 rounds of collective bargaining, the provision of Canadian Controlled Private Corporation (CCPC) shares provided a strategic advantage to Hydro One's bargaining position because of the tax advantages of this form of equity,[3] which conferred substantial benefits to the PWU and SUP represented employees who were eligible to receive it, and resulted in ongoing cost-savings for Hydro One.

This form of compensation has inherent cost savings (in comparison to base wage increases) because it is only provided to a defined class of employees who meet the eligibility requirements, and it is time-bound. Thus, the group of PWU and SUP represented employees who receive share grants will diminish over time, and the long-term impact to pension costs is mitigated due to lower increases in base wages. Eligibility for share grants will cease in 2028 for PWU, and in 2029 for SUP employees who maintain

[3] CCPC shares are a unique form of share that can only be issued before an organization undergoes an IPO. The value of the shares is not required to be included on the individual recipient's tax return in the year the share is issued, but rather only in the year the share is sold. Once shares are sold, Hydro One must report the taxable benefit on the recipient's T4. However, if the share has been held by the recipient for at least two years, the recipient can claim a tax deduction of 50% of the value of the shares sold.

active employment and continue contributing to the pension plan. Share grants are not issued to retired employees collecting pension benefits.

Lump sum payments were provided for both PWU and SUP during the 2015/2016 rounds of collective bargaining. This enabled Hydro One to renew its agreements with the PWU and SUP for wage increases that were less than other utility peers for the years 2015-2018 (the PWU renewal agreement) and 2016-2019 (SUP renewal agreement).

Moreover, Hydro One was able to offer equity compensation in exchange for the PWU accepting further changes to Pension Plan contribution rates, as well as significant changes to the rules of the plan. These changes took effect in 2025 and apply to future service accrual and will have a cost-savings impact on the Hydro One Pension Plan (HOPP). Progress has also been made in past negotiations with the SUP, during which similar changes to the pension plan were achieved. Further details pertaining to the changes to the HOPP are provided in section 4.2 below.

As of April 1, 2026, approximately 2,200 PWU-represented employees and 1,110 SUP-represented employees were receiving share grants. As attrition occurs (voluntary, non-voluntary and retirement), the number of share grants provided is anticipated to decline, as shown in Table 1 and Table 2 below.

1

Table 1 - Share Grants Issued to PWU

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Actual Units Disbursed										Forecasted		
Number of Shares	371,610	353,134	341,308	327,442	309,365	288,298	269,338	259,227	249,678	232,300	231,183	230,230	-
Change from 2017	--	-5%	-8%	-12%	-17%	-22%	-28%	-30%	-33%	-37%	-38%	-38%	-

2

Table 2 - Share Grants Issued to SUP

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Actual Units Disbursed										Forecasted		
Number of Shares	n/a	128,327	121,633	114,242	108,012	100,487	92,856	89,087	85,992	81,910	81,418	81,013	80,399
Change from 2018	n/a	--	-5%	-11%	-16%	-22%	-28%	-31%	-33%	-36%	-37%	-37%	-37%

3.1.2 EMPLOYEE SHARE OWNERSHIP PLAN (ESOP)

Hydro One allows eligible represented employees to acquire common shares of Hydro One Limited through payroll deductions. The ESOP is an important element of total compensation because it: (i) aligns employee and shareholder interests; (ii) facilitates the attraction and retention of talent; and (iii) promotes a culture of employee ownership that encourages accountability and long-term commitment to the Company's success.

In the 2023 round of collective bargaining, Hydro One and the SUP agreed to remove the ESOP eligibility exception for regular SUP employees who were hired before September 1, 2015, and those receiving or eligible for IPO share grants. From 2023 – 2025, employees were able to contribute between 1% and 4% of their base salary, made in whole percentages (i.e., multiples of 1%) through payroll deductions on a bi-weekly basis, and Hydro One would match 25% of the employee contribution. Beginning in 2026, SUP employees could contribute between 1% to 5% of their base salary, made in whole percentages (i.e. multiples of 1%) through payroll deductions on a bi-weekly basis, and Hydro One will match 33% of the employee's contribution.

Similarly, in the 2023 round of collective bargaining, Hydro One and the PWU agreed to allow PWU represented employees the choice to opt in to the ESOP. From 2023 – 2025, PWU represented employees could contribute between 1% and 4% of their base salary, made in whole percentages (i.e. multiples of 1%) through payroll deductions on a bi-weekly basis, and Hydro One would match 33% of the employee's contribution. In late 2025, Hydro One and the PWU agreed to increase the eligibility for employees to contribute between 1% to 5% of their base salary, made in whole percentages, and the employer match remained 33%.

3.1.3 PENSION PLANS - REPRESENTED GROUPS

Regular full-time employees represented by the SUP and the PWU are members of the Hydro One Pension Plan (HOPP). The HOPP is a defined benefit pension plan based on the Ontario Hydro Pension Plan (OHPP) which was established on November 1, 1923. The rights to bargain the terms of the OHPP for represented staff were entrenched during

collective bargaining with CUPE Local 1000 (PWU) in 1966 and with the SUP since its inception as a union in the early 1990's. In 2000, after the Ontario Hydro demerger, the HOPP was registered and provided a restatement of the existing OHPP terms under the new employer, Hydro One.

PWU HOPP members are subject to a retirement formula (age + years of service) of 85 points (referred to as the rule of 85) to be eligible for an undiscounted pension (members with 35 years of service are eligible for an undiscounted pension irrespective of points). The pension benefit upon retirement is based on the average of an employee's highest consecutive three years' earnings for pensionable service up to March 31, 2025. For service accrued after April 1, 2025, the pension benefit amount is based on an average of the members' five highest years' earnings. These changes were negotiated during collective bargaining in 2016 and will continue to result in cost savings during the 2028-2032 planning period as detailed below in section 4.2.

SUP represented employees are members of the HOPP and are divided into two subgroups: plan members hired prior to November 17, 2005 (the legacy plan), and those hired after November 16, 2005 (the new plan). The applicable pension rules depend on plan participation.

SUP-represented employees in the legacy plan are currently subject to the rule of 82, and their pension benefit amount is based on the average of the member's highest consecutive three years' earnings for service up to March 31, 2025. For service earned from April 1, 2025, onwards, the pension benefit is based on an average of the member's highest five years' earnings (and the rule of 82 will continue to apply).

SUP-represented employees in the new plan are subject to the rule of 85, and their pension benefit amount is based on the average of the member's five highest years' earnings. These rules have been in place since November 17, 2005, and were introduced following a protracted labour dispute between Hydro One and the SUP. All new employees hired into a SUP-represented role on or after November 17, 2005, are subject to these

new plan rules. These changes have reduced Hydro One's pension costs as detailed below in section 4.2.

3.2 COMPONENTS OF COMPENSATION: MANAGEMENT & NON-REPRESENTED GROUPS

The Company's MGT-NR compensation program and philosophy are grounded in the principles of pay-for-performance and pay-at-risk. MGT-NR compensation levels are established based on the guiding objectives of attracting and retaining high-caliber talent, emphasizing performance-based outcomes, and maintaining market competitiveness. These principles are designed to support the achievement of the Company's strategic objectives while ensuring that total compensation levels remain reasonable and aligned with stakeholder interests.

Compensation for MGT-NR employees depends on achievement of measurable performance indicators tied to Company priorities and objectives. By comparison, a shift away from performance pay in favour of increased base salaries would increase Hydro One's fixed costs and reduce the company's ability to align employee performance with business objectives.

3.2.1 BASE SALARY

The base pay for MGT-NR employees is based on a salary structure that is segmented into core and operations. Creating distinct salary ranges for operations roles provides Hydro One with a competitive advantage because it can tailor compensation to attract talent with specific education, skills and knowledge necessary for work related to transmission and distribution systems. The salary ranges for core services positions are based on attracting and retaining talent with education, skills and knowledge that are not necessarily specific to the utility industry. Hydro One can recruit broadly for such roles given the wider availability of the required skill sets and expertise. Salary segmentation ensures that Hydro One does not overpay for skills found more readily in the market and remains aligned with market compensation practices.

Each salary range has a minimum, mid-point, and maximum aligned to market. The compensation program targets pay approximately at the market median to balance talent attraction and retention, facilitate represented employees moving into management roles and maintain reasonable compensation costs.

Base salaries are adjusted through a merit program. Hydro One does not provide automatic annual across-the-board or cost-of-living increases. For MGT-NR employees, merit increases are assessed and determined annually on an individual basis and are contingent on performance. They are not guaranteed.

3.2.2 PERFORMANCE-BASED COMPENSATION

Full-time MGT-NR employees are eligible for annual incentive-based pay as a component of their total cash compensation. The Short-Term Incentive Plan (STIP) is designed to reward participants for the achievement of annual team (corporate) and individual performance goals. The team performance component reflects Hydro One's role in delivering value to customers and includes measures such as health and safety, sustainability, customer (including metrics such as overall brand impression, reliability and customer satisfaction), financial stability and work program. The individual performance measures are made up of a set of goals specific to each employee that drives toward strategic outcomes to benefit the Company and therefore its ratepayers. This structure creates a connection between compensation and Hydro One's ability to deliver safe, reliable and cost-effective service to customers. Target STIP payouts are based on a percentage of the employee's annual salary and role level. They are pro-rated to reflect any salary changes that may occur during the year. Figure 1 below illustrates the formula used to determine total STIP payout.

Figure 1: STIP Payout Formula

Directors, vice-presidents and executives are eligible to participate in a Long-Term Incentive Plan (LTIP). Participation in the LTIP is determined annually by Hydro One's Board of Directors. The LTIP supports the attraction and retention of experienced leaders and aligns a portion of management compensation with the achievement of long-term performance objectives and company results. By linking compensation to long-term outcomes, the LTIP reinforces management accountability for delivering sustainable value to customers, shareholders and other stakeholders. LTIP awards are eligible for payment three years following the grant date.

Hydro One currently grants two types of LTIP awards:

- Restricted Share Units (RSUs): Awards of notional shares that vest after three years, earn dividend equivalents and are settled in cash, less statutory deductions at the end of the vesting period. Their value at the time of payout is based on the Company's share price when units vest.
- Performance Share Units (PSUs): Time and performance-vested awards of notional shares that vest after three years and earn dividend equivalents. The final number of units will range from 0% to 150% of the vesting PSUs, depending on Hydro One's achievement of the performance measures communicated at the time of grant. The performance measures and their associated targets are approved annually by the Board of Directors. The final number of PSUs is delivered in shares, less statutory deductions at the end of the vesting period.

3.2.3 EMPLOYEE SHARE OWNERSHIP PLAN (ESOP)

MGT-NR employees are eligible to participate in an ESOP. Eligible employees can contribute between 1% to 6% of their base salary, made in whole percentages (i.e. multiples of 1%) through payroll deductions on a bi-weekly basis, and Hydro One will provide a 50% match on contributions. The ESOP is an important element of the total compensation program because it: (i) aligns employee and shareholder interests; (ii) facilitates the attraction and retention of talent; and (iii) drives a culture of performance aligned with the Company's management compensation philosophy.

3.2.4 PENSION AND BENEFITS

MGT-NR employees hired between October 1, 2015 and present day participate in a Defined Contribution Pension Plan (DCPP). Employees hired prior to October 1, 2015, participate in the HOPP. Future service changes to the HOPP and the introduction of the DCPP have achieved reduced pension expenses for the Company as detailed below in section 4.3, while still providing employees with company sponsored plans to save for retirement.

As the workforce evolves through normal attrition and hiring, the proportion of active employees participating in the DCPP continues to increase while participation in the HOPP declines. This shift supports a more sustainable pension cost structure by reducing future pension obligations and limiting the growth of pension-related costs. Active HOPP membership is projected to decline by approximately 41% from 2023 – 2032, while DCPP membership is projected to increase by approximately 137% over that same period.

MGT-NR employees are eligible to participate in core health and dental and flex benefits program. The program was redesigned and launched January 1, 2023, based on the principles of market alignment, internal equity, a wellness focus and encouraging internal talent movement from represented to management roles, which is a challenge for the organization.

3.2.5 EXECUTIVE COMPENSATION

From 2018 to January 1, 2023, Hydro One Networks Inc. was subject to legislation that prohibited the recovery of compensation costs related to executive positions through rates. The direction was limited to Hydro One Limited Officers. Hydro One voluntarily elected to exclude the compensation of an additional four executive officer positions that comprised the Executive Leadership Team (ELT) at that time.

For the 2028-2032 planning period, the Company will continue to exclude the compensation of the following Hydro One Limited Officers and ELT positions:

- Chief Executive Officer
- Chief Financial & Regulatory Officer
- Chief Operating Officer;
- EVP, Capital Portfolio Delivery;
- EVP, Safety, Operations and Customer Experience;
- General Counsel;
- EVP, Digital and Technology Solutions;
- EVP, Corporate Affairs; and
- EVP, Head of Human Resources.

4.0 PROGRESS IN MANAGING COMPENSATION COSTS

Overall compensation costs are determined by the workforce mix and the type and level of compensation paid to employees. The Company's compensation costs are predominantly driven by collective bargaining outcomes because 91% of Hydro One's workforce is represented by unions. Hydro One operates critical infrastructure and relies on a highly skilled workforce to perform work in a safety sensitive environment. As a result, compensation arrangements, including pension and benefits programs, are designed to support the attraction and retention of qualified employees to safely operate, maintain, and build the system.

During collective bargaining, Hydro One strives to balance achieving an appropriate market-based total compensation approach with workforce flexibility, productivity

enhancement, and appropriate cost containment. Hydro One has continued to make progress in terms of compensation levels in each round of collective bargaining while maintaining the workforce required to support its operations and investment plan.

Hydro One will continue to pursue cost-saving opportunities at each future round of collective bargaining, consistent with previous feedback from the OEB.

4.1 RECENT COLLECTIVE BARGAINING RESULTS

Hydro One inherited its union recognition and collective agreements from Ontario Hydro in 1999. Both the PWU and SUP originate with Ontario Hydro, the predecessor company that was split into five entities in 1999 at the time of the Ontario Hydro demerger. The current unionized environment at Hydro One and its impact on compensation costs continue to be influenced by this fact. Important terms in collective agreements governing working conditions, wages, benefits and pensions, and the interpretation of such terms, were initially non-negotiable for the Company.

Various core terms inherited from the Ontario Hydro demerger have driven increased compensation costs for Hydro One, including:

- automatic wage progression decoupled from performance outcomes;
- premium pay for overtime; and
- employer-paid health and dental coverage, a defined benefit pension plan and retiree health benefits.

Changes to inherited and previously negotiated terms can only be achieved through consensus between Hydro One and the applicable union upon the expiration of a collective agreement. External factors outside of Hydro One's control, which influence wage rates and other compensation related negotiations during the collective bargaining process, include inflation, unemployment rates, wage increases from peers and comparators, and demand for specific skill sets. These factors also influence employee expectations of both their union and management during collective bargaining.

As detailed below, over time and through multiple rounds of collective bargaining, Hydro One has made progress in reducing its compensation costs for represented employees by bringing them closer to the market average amongst peers.

4.1.1 PWU AGREEMENT

Since the last rate filing, Hydro One and the PWU have had two opportunities to negotiate the terms and conditions of their collective agreements. The previous collective agreements were in effect from April 2023 – October 2025 and the current collective agreement is in effect from October 2025 – March 2028. Hydro One's collective bargaining objectives focused on delivering value for customers through productivity enhancements, workforce flexibility and appropriate cost containment, while continuing to attract and retain the qualified employees needed to operate and support critical infrastructure safely and reliably.

During the period of April 2023 – October 2025, Hydro One and the PWU were operating under two collective agreements: the PWU Main Agreement and the Customer Service Organization (CSO) Agreement. Key compensation changes reflected in those agreements were as follows:

- Annual base wage increases of 4.5% in 2023, 4.0% in 2024, and 3.5% in 2025. The economic climate, which included post-COVID-19 return to office, significant inflation and employee expectation of substantial increases, had an impact on these negotiations, resulting in higher base wage increases in many collective agreements across the industry. The agreement, however, does not contain a cost-of-living adjustment (COLA), an escalator clause, lump sum payments or signing bonuses.
- Eligibility to enroll in the ESOP by electing to purchase 1% to 4% of base salary, with Hydro One matching their contribution at 33%.
- Minor increases to health benefits such as the ability to purchase wigs for employees with defined and documented medical diagnoses on file, and an increase in the coverage cap for psychologists to align with wellbeing programming

and supports. These key benefits changes were intended to support a healthy and engaged workforce.

The current collective agreement between Hydro One and the PWU was negotiated in 2025 and is effective from October 1, 2025 to March 31, 2028. Key changes in the current collective agreement impacting compensation costs include:

- Merging of the PWU Main Agreement and the CSO Agreement to improve administrative efficiency and consistency in the terms and conditions of employment. A unified agreement mitigates interpretive risk and supports operational flexibility.
- Annual base wage increases as follows: 1.0% in fall 2025, 3.5% in 2026, and 3.5% 2027. The agreement does not contain a COLA, an escalator clause, lump sum payments or signing bonuses.
- Hydro One was successful in the negotiation of Mid-term-40-3 which ensures that employees who join Hydro One because of a merger or acquisition must remain actively employed for five years to access post-retirement benefits. This assists in reducing overall benefit obligations, which in turn reduces overall compensation costs.

4.1.2 SUP AGREEMENT

Since the last rate filing, Hydro One and SUP have had two opportunities to negotiate. The previous collective agreement was in effect from April 2023 – October 2025 and the current collective agreement is in effect from October 2025 – March 2028. While the nature of the work differs across bargaining units, Hydro One's collective bargaining objectives remain broadly consistent. As such, Hydro One’s objectives were to enhance workforce flexibility, support productivity improvements, manage compensation costs responsibly, and maintain the skilled workforce required to safely and reliably deliver electricity service and execute its investment plan.

The Collective Agreement covering April 2023 – October 2025 included the following key compensation terms:

- Annual base wage increases of 4.5% in 2023, 4.0% in 2024 and 3.5% in 2025. The agreement, however, did not contain a COLA, an escalator clause, lump sum payments or signing bonuses. The economic climate, which included post-COVID-19 return to office, significant inflation and employee expectation of substantial increases, had an impact on these negotiations, resulting in higher base wage increases in many collective agreements across the industry.
- Removal of the ESOP eligibility exception for regular SUP staff who were hired before September 1, 2015, and those receiving or eligible for IPO share grants. Employees could contribute 1% - 4% of their base salary and the Hydro One contribution remained at 25%.
- Minor increases to health benefits such as an increase in the coverage cap for psychologists and an increase of coverage for paramedical services. These key benefits changes were intended to support a healthy and engaged workforce.

The current collective agreement between Hydro One and the SUP was negotiated in 2025 and is effective from October 1, 2025, to March 31, 2028.

Key changes in the current SUP collective agreement are as follows:

- Annual base wage increases : 1.0% in fall 2025, 2.75% in 2026 + 1% equity share grant for regular employees, 2.75% in 2027 + 1% equity share grant for regular employees. This negotiated increase including a 1% equity share grant (common shares) rather base pay, mitigated the compounding impact of a larger base salary increase, thereby reducing future pension obligations. The cost mitigation achieved by incorporating equity grants as part of total compensation results in an estimated savings of approximately $3.2M from 2026 to 2032. The agreement does not contain a COLA and no lump sum payment or signing bonus.
- ESOP contribution increases for regular employees between 1% - 5 % (from 1% - 4%) and an increase in matching contribution from 25% to 33% to be implemented within six months of ratification.
- Reduced pay scale for professional trainees (New Grads) by introducing lower wage levels for new hires.

- Maintained flexibility with no change to the existing Purchased Services language, which permits contracting.

4.1.3 CUSW AGREEMENT

Hydro One negotiates directly with CUSW[4] which represents construction electricians, Power Line Technicians (linespersons) and groundpersons employed by Hydro One. The collective agreement between Hydro One and CUSW extends to employees of CUSW-represented contractors (e.g. Valard) performing work on behalf of Hydro One.

In advance of the 2026 round of collective bargaining, Hydro One experienced elevated levels of voluntary attrition among CUSW-represented linespersons. Hydro One believes a contributing driver of the attrition was wage differentials relative to compensation offered by other unionized employers for comparable work, especially organizations represented by the International Brotherhood of Electrical Workers (IBEW) and the PWU.

Accordingly, an objective of this collective bargaining process was to improve the attraction and retention of skilled trades resources through more competitive compensation. This was necessary to support workforce stability and ensure the Company maintains the skilled labour capacity required to execute its capital investment plan.

The resulting agreement reflects a total compensation package designed to be more closely aligned with prevailing external market benchmarks, including compensation provided to employees with similar skills, certifications, and job requirements within the electrical power sector, such as those represented by the IBEW and the PWU that work in the Electrical Power Sector.[5] Key changes to the CUSW journeyperson total wage package results in the following increases:

- 8% in 2026

[4] This is distinct from other building trades unions that represent Hydro One casual employees (such as the Labourers, or Operating Engineers) who engage in collective bargaining with EPSCA, which acts as an agent for its employer members, such as Hydro One, OPG, and Bruce Power.
[5] IBEW currently represents 14 locals across the province that support work for EPSCA-affiliated employers.

- 5% in 2027
- 3% in 2028
- 2% in 2029

While still below IBEW and PWU comparator levels, these increases position Hydro One to more effectively compete for skilled trades talent required to support the execution of its investment plan. Table 3 below highlights the total wage package differential between CUSW, IBEW-EPSCA, and Hydro One PWU Appendix A (Causal) Journeypersons.

Table 3 - Total Wage Package Differential

(CUSW, IBEW and Hydro One Appendix A)

Year	Hydro One CUSW ($)	EPSCA-IBEW*($)	Hydro One PWU Appendix "A" ($)	Hydro One CUSW v. EPSCA IBEW	Hydro One CUSW v. Hydro One PWU Appendix "A"
2023	63.33	68.21	67.32	-7.71%	-5.93%
2024	64.60	69.58	70.06	-7.71%	-7.79%
2025	65.89	73.75	73.29	-11.93%	-10.10%
2026	71.16	77.81	75.86	-9.34%	-6.19%
2027	74.72	81.31	78.51	-8.82%	-4.83%
2028	76.96	83.75		-8.82%	-
2029	78.50	85.43		-8.83%	-

** This is the average rate of all IBEW locals across the province. Unlike CUSW, the IBEW has a different rate for each local, so to compare the two the average IBEW local rate was used.*

4.1.4 ACHIEVING CONTRACTING OUT FLEXIBILITY

Hydro One has reached agreements with the PWU, SUP and CUSW which allow greater flexibility for Hydro One to contract out specific work where it is advantageous because of associated compensation cost savings compared to completing the work internally, an increased ability to meet demand work and specialized short-term scope, and a decreased need to maintain specialty equipment and fleet. These collective bargaining achievements are detailed in Exhibit E-06-02, section 2.4.1

4.2 ADDRESSING THE HYDRO ONE PENSION PLAN (HOPP)

The HOPP is a major element of compensation contributing to Hydro One's compensation costs. The HOPP predates Hydro One; it is a long-standing feature of the legacy Ontario Hydro collective agreements. Compensation costs driven by the HOPP have been addressed by Hydro One through both extraordinary actions (an impasse in negotiations resulting in a work stoppage and arbitrated outcome) and more typical approaches (incremental changes negotiated during successive rounds of bargaining). Hydro One's focus on obtaining pension plan changes through the collective bargaining process along with wage increases at or below industry levels has contributed to the continuous improvement of its compensation levels relative to market. Outlined below are the historical and more recent changes which have contributed to this improved market position and have allowed Hydro One to maintain a flexible, efficient, and appropriately sized workforce.

SUP PENSION PLAN CHANGES

As discussed above in section 3.1.4, pension plan formula changes were introduced for SUP represented staff hired on or after November 17, 2005. The average earnings period increased from 36 to 60 months, and the requirement for an undiscounted pension increased from 82 to 85 points. The indexing formula of both the post-2005 SUP plan (and the management plan) was reduced from 100% to 75% of CPI. Hydro One obtained these SUP-related amendments through arbitration following a work stoppage that lasted over three months in 2005.[6]

The changes to the SUP pension plan, that affect employees hired on or after November 17, 2005, constitute an increasingly significant source of savings as a greater percentage of SUP represented employees come under the new plan. Through normal workforce attrition and hiring, membership in the legacy plan continues to decline, reducing future

[6] In the round of bargaining that preceded this work stoppage, Hydro One had sought a two-tier wage schedule, improved contracting provisions, and a revision of base hours from 35 to 40, in addition to pension changes. Following this protracted work stoppage and subsequent government-imposed arbitration, only the pension plan rule changes noted above were achieved.

pension obligations and supporting a more sustainable pension cost structure while continuing to provide employees with employer-sponsored retirement benefits. As shown in Figure 3 below, the SUP membership in the legacy plan is expected to decline from 18% in 2023 to 8% in 2032, while participation in the new plan is expected to increase from 82% to 92%.

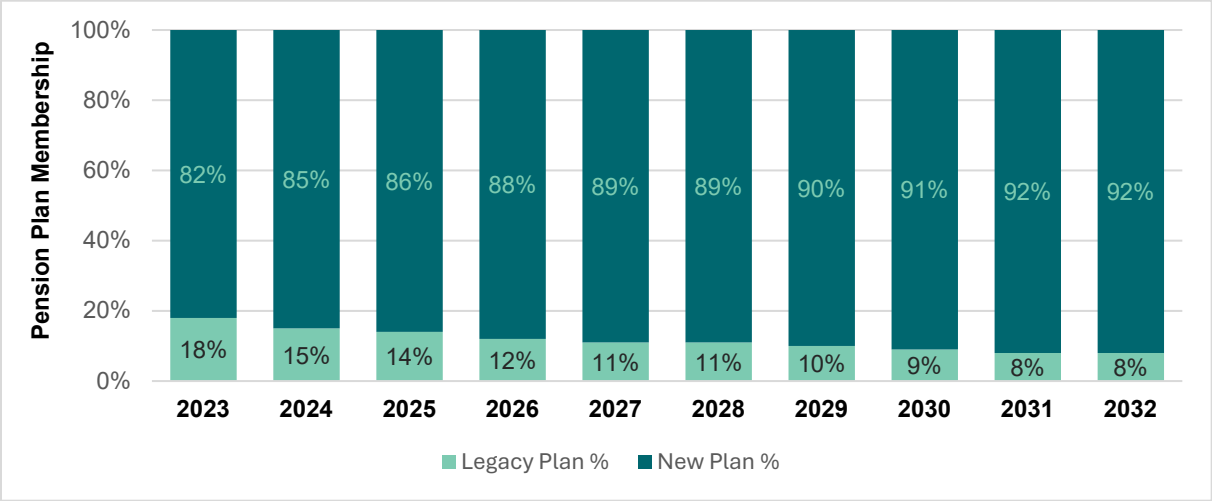

Figure 3: Decline in Society Legacy Plan Members vs. New Plan Members

The estimated cost savings from the above changes in the SUP pension plan totaled $22.5M from 2023 to 2025 and are projected to be a further $86.9M from 2026 to the end of 2032. The annual amounts that comprise these totals are shown in Table 4 below.

Table 4 - Estimated Annual SUP Pension Plan Savings due to 2005 Plan Changes[7]

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Savings ($M)	6.8	7.7	8.0	9.4	10.3	11.5	12.6	13.5	14.4	15.2	109.4

[7] The savings have been estimated by applying the reduction in funding normal cost (as a percentage of payroll) resulting from the change in benefit entitlements to the actual and projected payroll for Post 2005 Society members over the 2021–2032 period. This methodology is consistent with the approach used for the 2021 estimates. Amounts for 2021–2024 reflect actual payroll levels (based on historical valuation data provided by Telus). Amounts for 2025–2032 reflect projected payroll levels, based on the assumptions outlined in the Projected 2026–2032 Benefit Cost.

PWU PENSION PLAN CHANGES

In 2025, the PWU pension plan was amended to align more closely with the provisions of the new SUP pension plan, and the legacy MGT-NR defined benefit plan. Effective April 1, 2025, PWU employees became subject to a rule of 85 and a five-year final average earnings period, replacing the previous rule of 82 and three-year averaging period. As noted in Table 5 below, the estimated costs avoided from the plan changes discussed above for PWU members total $28.7M for the period from the end of March 2025 to the end of December 2032.

Table 5 - PWU Pension Plan Savings[8]

Year	2025 (April 1-Dec 31)	2026	2027	2028	2029	2030	2031	2032	Total
Savings ($M)	2.3	3.3	3.5	3.6	3.8	3.9	4.1	4.2	28.7

COST SAVINGS AS A RESULT OF CHANGES TO PENSION CONTRIBUTION RATES

Furthermore, incremental changes to contribution rates negotiated during various rounds of bargaining with both SUP and PWU have and will continue to yield cost savings and will help to improve the relative competitiveness of Hydro One's level of compensation.

In recent years, Hydro One has negotiated increases to employee pension contribution rates over multiple rounds of bargaining that result in cost savings. Since 2012, increases in employee contribution rates have shifted responsibility for funding the plan's annual normal cost from Hydro One to employees by approximately 25 percentage points.[9] This aligns with the gradual increase in employee contributions rates shown in Table 6 below.

[8] The savings have been estimated by applying the reduction in funding normal cost (as a percentage of payroll) resulting from the plan change to the projected payroll for PWU members over the April 2025 to December 2032 period. The reduction in funding normal cost has been estimated based on the December 31, 2024 valuation. Amounts for April 2025 to December 2032 reflect projected payroll levels.

[9] When only considering the impact of increase to employee contributions, Hydro One's share of the total normal cost is estimated to have decreased from 71% to 46%, a reduction of 25 percentage points. The current value of 46% is based on the actuarial valuation of the Plan as at December 31, 2024. The amounts under the 2012 Contribution Rates column were calculated using the same December 31, 2024, plan membership data, actuarial assumptions, methods and applicable plan provisions, except that the employee contribution rates were replaced with the rates in effect in 2012 for the respective employee groups (highlighted in table 7).

Table 6 - Pension Contribution Rate Changes PWU & SUP

	Pre-2011	Pre-2013	April 1 2013	April 1 2014	April 1 2015	April 1 2016	April 1 2017	April 1 2018 to present
PWU	4% Up to YMPE + 6% Beyond YMPE	4.5% + 6.5% *Apr 1, 2011 to Mar 31,2013*	5.5% + 7.5%	6.25% + 8.25%	7.25% + 9.25%	8.25% + 10.25%	8.75% + 11.25%	**8.75% + 11.25%**
SUP- Legacy Plan	4% + 6% Up to Nov 30, 2010	4.5% + 6.5% *Dec 1, 2010 to Mar 31, 2013*	5.25% + 7.25%	6.25% + 8.25%	7.0% + 9%	7.5% + 9.5%	8.25% + 10.25%	**8.75% + 11.25%**
SUP - New Plan	4% + 6% Up to Mar 31, 2013	4% + 6% Up to Mar 31, 2013	4.75% + 6.75%	5.75% + 7.75%	6.5% + 8.5%	7.0% + 9%	7.75% + 9.75%	**8.25% + 10.75%**

As a result of the compounded changes over time, the estimated funding (cash) savings from increasing SUP and PWU member contribution rates is $96.7M for the period of 2023-2032. The annual figures that comprise this total are provided in Table 7 below.

Table 7 - Estimated Savings from PWU & SUP Pension Contribution Rate Changes[10]

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Savings ($M)	6.8	7.5	8.2	8.8	9.5	10.1	10.7	11.2	11.7	12.2	96.7

[10] The savings have been estimated by applying the reduction in employee contributions resulting from the contribution rate change to the actual and projected employee contributions for PWU and SUP members over the 2021–2032 period. The reduction in employee contributions was extrapolated. This methodology is consistent with the approach used for the 2021 estimates. Amounts for 2021–2024 reflect actual employee contributions (based on historical valuation data provided by Telus). Amounts for 2025–2032 reflect projected employee contributions.

4.3 COMPENSATION COST REDUCTIONS DUE TO SHIFT TO DEFINED CONTRIBUTION PENSION PLAN

In 2015, Hydro One closed the MGT-NR Defined Benefit Pension Plan (DBPP), thereby reducing related compensation costs. This decision aligns with the market trend of introducing defined contribution pension plans as the primary form of retirement program. This program change will continue to yield savings as the demographics of the MGT-NR group continue to shift through retirements and voluntary turnover. As illustrated in Figure 4 below, forecasted turnover in the management workforce is expected to result in a shift in the number of MGT-NR employees in the legacy DBPP and a corresponding reduction in MGT-NR compensation costs.

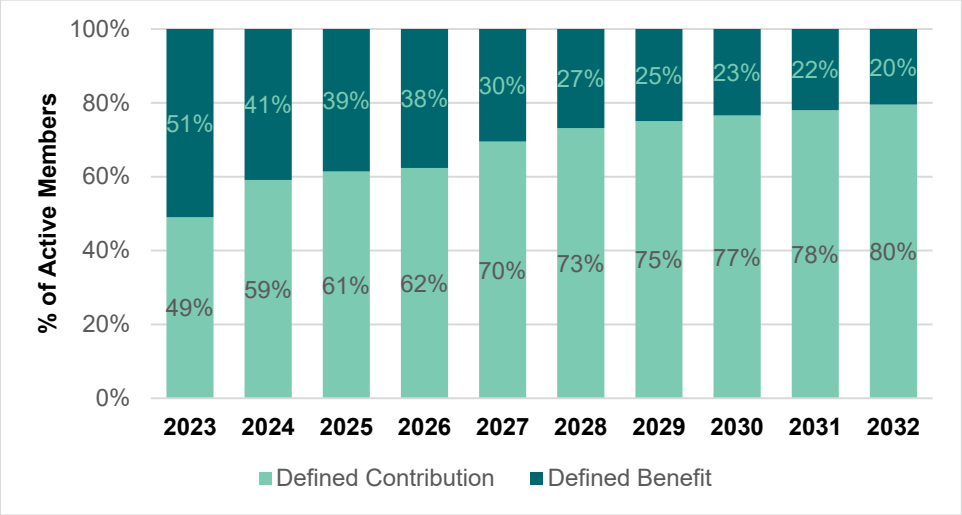

Figure 4: MGT-NR Pension Plan Membership Projections

As illustrated in Figure 4,[11] based on plan member data from 2026, as well as historical retirement turnover trends for the management segment, it is anticipated most management employees will be on the DCPP going forward. As of January 2026, there are 343 MGT-NR DBPP members and 568 DCPP members.

[11] Includes full-time regular employees in the MGT-NR group who are employed by Hydro One Networks Inc.

From January 1, 2023, to December 31, 2032, the estimated savings in Hydro One cash funding contributions (costs) because of closing the DBPP and opening the DCPP total $15.5M and are summarized in Table 8 below:

Table 8 - Estimated Hydro One Savings from Management Pension Plan Amendments[12]

Year	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Estimated Savings ($M)	1.6	2.1	1.0	0.9	1.2	1.5	1.6	1.7	1.9	2.0	15.5

5.0 HYDRO ONE'S LEVEL OF COMPENSATION RELATIVE TO MARKET

As described above, Hydro One has taken a disciplined and consistent approach with a view to aligning employee compensation with external market benchmarks. From 2008 to the present, the Company's efforts have made steady and significant progress in reducing its overall compensation levels relative to market.

In accordance with the OEB-approved settlement commitment from the last joint rate application, Hydro One engaged both WTW and Mercer to conduct updated compensation benchmarking studies in 2026.

WTW - MANAGEMENT COMPENSATION BENCHMARKING STUDY

To assess the competitiveness of MGT-NR compensation, Hydro One engaged WTW to conduct an independent market benchmarking study. WTW conducted a comprehensive assessment of Hydro One's management compensation structure (excluding the CEO and direct reports), to assess alignment with market. This study focused on Target Total Direct Compensation (TTDC), which encompasses the salary range midpoint, target bonus, and

[12] Savings were estimated by calculating the difference between DB and DC plan costs. Historical (2022–2025) DB pensionable earnings were derived from Hydro One payroll data, adjusted to include 50% of actual STIP amounts. Projected (2026–2032) pensionable earnings were based on the assumptions set out in the Projected 2026–2032 Benefit Cost Letter dated March 13, 2026, with DB pensionable earnings reflecting 50% of projected STIP amounts. DC costs were based on actual or projected payroll, as applicable.

target long-term incentives where applicable. The scope and focus of the study was consistent with prior versions of the WTW study. The WTW study report details the study methodology and results, and is attached to this exhibit as Attachment 3.

WTW's study shows that Hydro One's compensation is at market. Specifically, it indicates that Hydro One's TTDC, by weighted average, is positioned right at the market 50th percentile overall. This confirms that Hydro One's MGT-NR compensation structure is competitively aligned with the market – right in the middle of the market competitive range and supports the organization's ongoing commitment to attracting and retaining talent across all management segments.

MERCER - COMPENSATION BENCHMARKING STUDY

Hydro One engaged Mercer to conduct an updated custom market benchmarking study to assess the competitiveness of Hydro One's compensation paid to its workforce. The Mercer report, attached to this exhibit as Attachment 2, details this study and the results of it.

The Mercer study results show that Hydro One has made notable further improvement towards achieving market compensation levels since the time of the last study in 2020. Hydro One's overall compensation position (on an overall organization basis) is now only 1% above the market competitive range, and 6% above the P50 market median.[13] As Mercer has confirmed, an overall level of compensation within +/- 5% of the P50 median is within the market competitive range. These results, extracted from the Mercer report and showing the progression of results study-over-study since 2008, are set out in Figure 5 below.

[13] The overall result of 6% above the P50 market median reflects the combined results of the individual employee groups included in the study. Hydro One's MGT-NR group is -7% below P50, the trades and technical group is 7% above P50, and the energy professionals' group is 8% above P50.

			Total Remuneration (Current)													
			Variance to P50							Hydro One P50 Relative to Market P50						
	Hydro One Group	# of Hydro One Incumbents (2026)	2008	2011	2013	2016	2017	2020	**2026**	2008	2011	2013	2016	2017	2020	**2026**
Weighted Average	Non-Represented	*186*	-1%	-17%	-1%	2%	1%	-4%	**-7%**							
	Energy Professionals	*653*	5%	5%	9%	11%	12%	11%	**8%**							
	Trades and Technical	*2,679*	21%	18%	12%	16%	12%	10%	**7%**							
	Overall	***3,518***	***17%***	***13%***	***10%***	***14%***	***12%***	***9%***	***6%***							

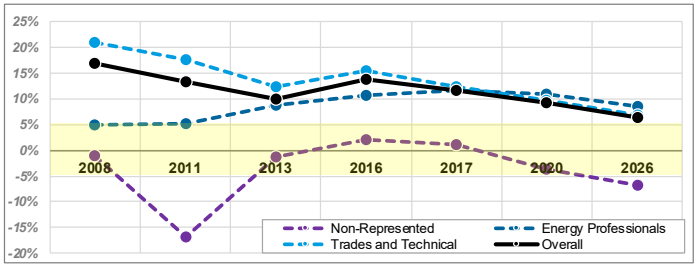

Figure 5: Benchmarking Results from the Mercer Study

The 2026 Mercer study results demonstrate a continued long-term trend of improvement in Hydro One's compensation position relative to market comparators. Since the first Mercer benchmarking study was conducted in 2008, Hydro One has progressively reduced the gap between its compensation levels and the market median, moving from 17% above P50 in 2008, to 9% above P50 in 2020, and to 6% above P50 in 2026 – which, as stated, now positions Hydro One at just slightly (1%) above the market competitive range.

Hydro One recognizes the importance of continuing to deliver service cost-effectively. The Company remains committed to operating with market-based levels of compensation. Mercer's report shows that the PWU and SUP represented roles (Energy Professionals and Trades and Technical) are the main drivers of Hydro One's compensation benchmarking results. Hydro One will continue its focus on ensuring its compensation levels are market competitive, including for the represented segment of its workforce.

6.0 CONCLUSION

Hydro One's compensation framework reflects the need to attract and retain the skilled workforce required to execute the investment plan and maintain safe, reliable and cost-effective operations to the benefit of customers.

Hydro One's compensation approach and strategies have contributed to measurable reductions in compensation-related costs. They have also improved Hydro One's overall compensation position relative to market benchmarks. The 2026 Mercer study demonstrates that Hydro One's compensation levels are more closely aligned with the market than in prior rate applications. Hydro One will continue to pursue opportunities to manage compensation costs and improve market alignment, while maintaining the workforce capabilities required to safely and reliably deliver its operations and investment plan.

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COMPENSATION TABLE (CHAPTER 2 APPENDIX 2-K: EMPLOYEE COSTS)

This attachment has been filed separately in MS Excel format.

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COMPENSATION TABLE – EXPLANATORY NOTES

For this application, the notes below outline the process followed in developing the presentation of the data and projected costs:

1. As directed by the OEB in Transmission application (EB-2019-0082), FTEs[1] have been broken down by OM&A and Capital, and by Transmission and Distribution. For rate groups, allocations are informed by historical actuals, while corporate functions are allocated using the Atrium cost allocation model (as described in E-04-08). As a result, the allocation of FTEs and costs presented in this application may result in variances from previously filed cost and FTE forecasts and actuals for the years 2023 – 2027.

2. The number and cost of FTEs allocated to non-HONI rate regulated (shareholder and other) are also shown in the Compensation Table. They are indicated separately from Distribution and Transmission. Non-HONI rate regulated (shareholder and other) FTEs represent the portion of FTEs (and related costs) that are allocated to Hydro One Remote Communities Inc., Hydro One Inc. (HOI), Hydro One Limited (HOL), Acronym, Aux Energy, Affiliated Transmission Projects (ATP), and existing partnerships. The FTEs and associated compensation costs for Non-HONI rate regulated (shareholder and other) are not included in Hydro One's customer rates.

3. The historical overtime spend percentage for each organization was used to project future overtime costs based on the forecasted stable overtime usage. Hydro One used 2023-2025 actual overtime costs as a percentage of 2023- 2025 actual base pay to calculate the percentage, which was then applied to the planned base pay costs for each year of the rate period. The increase in the planned cost

[1] At Hydro One, FTEs represent average monthly headcount over a 12-month period. A regular status employee who is budgeted for one year of work, represents one FTE. For casual employees, one FTE equates to 12 person months of work. For example, if one casual employee worked for six months they would account for 0.5 FTEs.

of overtime for the years 2028 to 2032 shown in the Compensation Table is attributable to the increase in base wages and FTEs over this period

4. The pension costs for the rate period are based on projected employer costs outlined in Exhibit E-07-01 and E-07-01, Attachment 1. The increases in 2025 and onwards reflect actuarial cost projections calculated in 2024, and are subject to change since they are based on: market conditions; funding position of the pension fund; the level of base pension earnings; and the resulting required contribution rates used to compute monthly contributions.

5. The Compensation Table includes the following categories of compensation:
   - Base Pay: base wages
   - Overtime
   - Performance dollars: Short Term & Long Term Incentive Program
   - Share Grants
   - ESOP: Employment Share Ownership Program
   - Burdens: Legislated (also known as Payroll) burdens, Pension, Other Post-Employment Benefits (OPEB) and Benefits

FTEs & Compensation Costs

In Table 1 below, Hydro One provides a year-over-year analysis of the FTEs and compensation costs broken down by Capital and OM&A, pursuant to the OEB's direction in EB-2019-0082, as well as year-over-year analysis for total FTEs and total compensation of the Transmission and Distribution organizations. The forecast amounts are based on a compounded annual growth rate, given that base pay and associated burdens are anticipated to increase year-over-year.

The variances over forecasted years are also a result of the changes to workforce levels and are impacted by the type (regular, casual) and the representation group of the FTEs that are increasing, decreasing or remaining flat in a given year.

Table 1 - Yearly Change in FTE and Compensation Costs

	2023 Actual	2024 Actual	2025 Actual	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2032 Plan
Total Transmission Capital FTE	**3,727**	**3,775**	**3,435**	**3,770**	**3,766**	**4,361**	**4,375**	**4,437**	**4,431**	**4,397**
YOY Change (Capital)		1.3%	-9.0%	9.8%	-0.1%	15.8%	0.3%	1.4%	-0.1%	-0.8%
Total Capital Compensation ($K)	643,084	670,385	613,586	705,045	729,949	861,807	891,776	931,611	958,861	985,403
YOY Change (Capital)		4.2%	-8.5%	14.9%	3.5%	18.1%	3.5%	4.5%	2.9%	2.8%
Total Transmission OM&A FTE	**835**	**805**	**730**	**801**	**800**	**926**	**929**	**942**	**941**	**934**
YOY Change (OM&A)		-3.6%	-9.3%	9.8%	-0.1%	15.8%	0.3%	1.4%	-0.1%	-0.8%
Total OM&A Compensation ($K)	144,042	142,933	130,314	149,738	155,027	183,031	189,396	197,856	203,643	209,280
YOY Change (OM&A)		-0.8%	-8.8%	14.9%	3.5%	18.1%	3.5%	4.5%	2.9%	2.8%
Total Distribution Capital FTE	**3,074**	**3,438**	**3,554**	**3,708**	**3,777**	**4,043**	**4,199**	**4,296**	**4,322**	**4,259**
YOY Change (Capital)		11.8%	3.4%	4.3%	1.9%	7.1%	3.8%	2.3%	0.6%	-1.5%
Total Capital Compensation ($K)	515,048	627,936	673,883	714,946	754,394	831,263	891,708	938,793	971,054	989,910
YOY Change (Capital)		21.9%	7.3%	6.1%	5.5%	10.2%	7.3%	5.3%	3.4%	1.9%
Total Distribution OM&A FTE	**1,668**	**1,652**	**1,435**	**1,497**	**1,525**	**1,632**	**1,695**	**1,734**	**1,745**	**1,720**
YOY Change (OM&A)		-0.9%	-13.2%	4.3%	1.9%	7.1%	3.8%	2.3%	0.6%	-1.5%
Total OM&A Compensation ($K)	279,457	301,822	272,068	288,646	304,573	335,607	360,011	379,021	392,045	399,658
YOY Change (OM&A)		8.0%	-9.9%	6.1%	5.5%	10.2%	7.3%	5.3%	3.4%	1.9%
Transmission Total FTE	**4,562**	**4,579**	**4,165**	**4,571**	**4,566**	**5,287**	**5,304**	**5,380**	**5,372**	**5,331**
Transmission Total Compensation ($K)	787,126	813,319	743,900	854,783	884,976	1,044,837	1,081,171	1,129,467	1,162,505	1,194,684
YOY Change FTE (%)		0.4%	-9.1%	9.8%	-0.1%	15.8%	0.3%	1.4%	-0.1%	-0.8%
YOY Change Compensation (%)		3.3%	-8.5%	14.9%	3.5%	18.1%	3.5%	4.5%	2.9%	2.8%
Distribution Total FTE	**4,743**	**5,090**	**4,989**	**5,205**	**5,302**	**5,676**	**5,894**	**6,030**	**6,067**	**5,979**
Distribution Total Compensation ($K)	794,506	929,757	945,951	1,003,592	1,058,966	1,166,870	1,251,719	1,317,814	1,363,099	1,389,568
YOY Change FTE (%)		7.3%	-2.0%	4.3%	1.9%	7.1%	3.8%	2.3%	0.6%	-1.5%
YOY Change Compensation (%)		17.0%	1.7%	6.1%	5.5%	10.2%	7.3%	5.3%	3.4%	1.9%

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Exhibit E-6-1
Attachment 2
Page 1 of 39

31 August 2026

COMPENSATION BENCHMARKING STUDY

Hydro One Networks Inc.

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Section 1

Introduction and Executive Summary

Hydro One Networks Inc. ("Hydro One"), through its counsel, has retained Mercer (Canada) Limited ("Mercer") in connection with its joint rate application for Distribution and Transmission (2028-2032) to:

1. Complete an updated Compensation Benchmarking Study ("Study") taking into account prior Ontario Energy Board ("OEB") directives; and,
2. Besides the Study results, opine on other factors that should be considered by the OEB in order to assess the reasonableness of Hydro One's overall compensation costs.

The Study is an independent, testable and repeatable market-based assessment of the degree of competitiveness of Hydro One's total compensation levels including salary, short-term incentives (including lump sum payments, when applicable), long-term incentives (including negotiated share grants, when applicable), pension and employer paid health and group benefits relative to a select peer group. Mercer undertook a customized survey of total compensation in the market, in order to provide reliable information. Previous versions of this Study were conducted in 2008, 2011, 2013, 2016, 2017, and 2020. The Study has now been repeated, following a similar methodology, in 2026.

Prior to each Study, every effort is made to ensure that the approach and methodology used continues to meet industry best standards and provides an appropriate assessment of the competitiveness of Hydro One's compensation levels.

Since 2008, the Study has included regulated Generation, Transmission and Distribution Utilities as well as comparable regulated businesses across Canada. Similarly, the job list has reflected a mix of Transmission, Distribution and Functional benchmark jobs. However, in order to maintain the effectiveness of the Study, the comparator group ("peer group") and job list are reviewed prior to each Study to ensure a reflection of Hydro One's changing talent landscape and nature of the workforce. This review has resulted in some updates to the comparator organizations (see page 11) and list of survey jobs (page 13) included in the Study. While these updates may have an impact on the study-over-study comparison, Mercer believes they better reflect the current workforce composition and balance of jobs at Hydro One, as well as the landscape in which Hydro One competes for talent.

The findings of the compensation benchmarking analysis are documented below. A study-over-study trend analysis is provided, as well findings from an overtime policy review and short and long-term incentive prevalence benchmarking review.

In response to item #2 above, though market competitiveness in respect of levels of pay continue to be a reliable factor that should be considered when assessing the reasonableness of Hydro One's overall compensation costs, Mercer's view remains that it should not be the single determining factor. In addition to market competitiveness, consideration should also be given to the impact that Hydro One's workforce size, mix and tenure have on overall compensation costs. Efficiency in respect of workforce composition,

can result in overall compensation costs being reasonable even if pay levels (on a per employee basis) may be above market. Further, there are likely cost saving benefits that result from managing a highly skilled and tenured workforce, including savings through increased productivity and greater employee effectiveness. These factors are addressed further under section 2 below (see page 5).

Summary of Compensation Benchmarking Results

The Study compared the competitiveness of Hydro One's total compensation pay levels to a peer group of Transmission, Distribution and Generation organizations, supplemented with participants from a similar regulatory environment. The Study reflects 3,518 Hydro One employees in 32 benchmark jobs which represents 52% of Hydro One's total regular full-time equivalents population. Overall, the analysis reflected 21,905 incumbents employed in the Canadian energy and/or adjacent sectors. This represents an increase in both the number of Hydro One employees and incumbents in comparator organizations included in the analysis, compared to the 2020 Study.

On an overall weighted average basis, **Hydro One is positioned approximately 6% above the market 50th percentile ("P50" or "median") for total compensation ("total remuneration")**. In comparison to the 2020 Study, Hydro One's overall weighted average market positioning has noticeably reduced relative to the market P50 / market 50th percentile / market median. Specifically, it has moved closer to the market median – from 9% above the market 50th percentile for total compensation in the 2020 Study down to 6% above in the 2026 Study.

When assessing compensation competitiveness, Mercer considers compensation levels to be competitive on an overall/employee group basis when it is within +/- 5% from the target market positioning (i.e. the market competitive range), which is the market 50th percentile for Hydro One. **Hydro One is positioned 1% outside the market competitive range. This is a noticeable reduction in positioning compared to being 4% outside the market competitive range in the 2020 Study.**

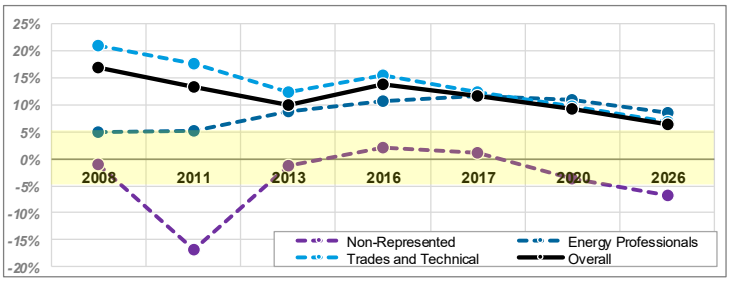
The market positioning for every Hydro One employee group included in the Study moved closer to the market median (i.e. experienced a reduction in market positioning) relative to the 2020 Study results.

Hydro One's trend towards the market median has been supported by a combination of factors specific to Hydro One. Some of these factors have had an immediate impact, while others, though implemented in the past, continue to have a trailing impact as tenured employees at the higher end of salary ranges / wage grids and/or on legacy plans are replaced with new employees. Amongst others, Hydro One's increased use of a cost-effective mix of workers has had an immediate contributory impact on the trend towards the market median. However, legacy pension plans that were in place prior to the formation of Hydro One, continue to limit a quicker shift towards the market median. See page 16 for details on these factors.

Table 1 below summarizes the results of the 2026 Study compared to the results of the 2008, 2011, 2013, 2016, 2017 and 2020 studies. The market competitive range (+/- 5% of the market 50th percentile) is highlighted in **yellow** in the chart.

Table 1

			Total Remuneration (Current)													
			Variance to P50							Hydro One P50 Relative to Market P50						
	Hydro One Group	# of Hydro One Incumbents (2026)	2008	2011	2013	2016	2017	2020	**2026**	2008	2011	2013	2016	2017	2020	**2026**
Weighted Average	Non-Represented	*186*	-1%	-17%	-1%	2%	1%	-4%	**-7%**							
	Energy Professionals	*653*	5%	5%	9%	11%	12%	11%	**8%**							
	Trades and Technical	*2,679*	21%	18%	12%	16%	12%	10%	**7%**							
	Overall	***3,518***	***17%***	***13%***	***10%***	***14%***	***12%***	***9%***	***6%***							



Summary of Overtime Policy Benchmarking Results

Actual overtime hours and costs are highly variable and difficult to normalize across the peer group used for the Study. As such, to ensure appropriate comparisons are made, Mercer compared Hydro One's overtime policy to the overtime policies found in the comparator group. By doing this, Mercer was able to make a direct comparison of the alignment between Hydro One's overtime policy relative to policies in peer organizations. Below are Mercer's findings from the review:

i) **Overtime Rate:** Similar to the findings from the 2020 overtime policy review, across all overtime types (e.g. weekday, weekends, call outs, etc.) Hydro One's overtime rates continue to be at or below the market median.

ii) **Tiered Rate:** Where tiered rates are used, though Hydro One is aligned with the most prevalent tier rate range of 1.5x – 2x, the amount of hours worked that Hydro One requires to move to the next overtime rate tier (e.g. 1.5x for first 2 hours and 2x afterwards), is lower than the market median. Specifically, Hydro One switches to a higher tier after 2 hours whereas the market median is 4 hours.

iii) **Minimum Hours for Standard Overtime:** Hydro One is aligned with the predominant market practice of offering minimum overtime hours to employees. That said, 60% of Hydro One's unions reviewed have a minimum number of hours that is higher than the most prevalent amount provided within the peer group.

iv) **Overtime Tracking and Approval Process:** Hydro One's overtime tracking and approval process continue to be aligned with predominant market practice.

Table 2 below presents the prevalence of overtime pay rates across different overtime types for Hydro One and the comparator group. The most prevalent overtime rate for each category is highlighted in **blue**. Please refer to page 20 for additional information and the definition of the types of overtime referenced.

Table 2

	Pay Rate Across Overtime Types					
	Pay Rate	Standard	Call Out	Weekend	Statutory Holiday	Vacation
Market	1.5x	9%	9%	9%	5%	9%
	1.5x - 2x	23%	18%	14%	14%	14%
	2x	64%	73%	77%	77%	77%
	2x - 2.5x	0%	0%	0%	5%	0%
	2x - 3x	5%	0%	0%	0%	0%
Hydro One	1.5x	20%	20%	0%	0%	20%
	1.5x - 2x	40%	40%	20%	0%	20%
	2x	40%	40%	80%	100%	60%
	2x - 2.5x	0%	0%	0%	0%	0%
	2x - 3x	0%	0%	0%	0%	0%

Summary of Short-Term Incentive ("STI") Plan and Long-Term Incentive ("LTI") Plan Benchmarking Results

Across all comparator organizations that provided data for a Non-Represented benchmark job, 83% provide STI to their employees while 46% provide LTI. Hydro One is aligned with the market in that LTI is generally more prevalent at senior level jobs and in publicly traded organizations**.** This reflects senior level job's ability to better influence long-term business results.

Hydro One is generally aligned with the market prevalence in that all Non-Represented jobs are eligible for STI while only the Director level jobs in the benchmark job list (2 jobs) are eligible for LTI.

Section 2

Additional Factors to Consider When Assessing the Reasonableness of Hydro One's Overall Compensation Costs

Mercer has been asked to provide our opinion in response to the following question: Besides the level of compensation outlined in the Study results, are there other factors that would need to be considered by the OEB in order to assess the reasonableness of Hydro One's overall compensation costs? If so, please describe those factors.

There are additional factors that the OEB should consider when assessing the reasonableness of Hydro One's, or any other utility's, overall compensation costs. Although higher compensation levels drive higher unit (i.e. per employee) costs, they can also provide cost savings through increased productivity and greater employee effectiveness associated with an experienced, highly skilled and engaged workforce, for example. When evaluating the reasonableness of the total compensation costs for an organization, besides the organization's pay levels and employee effectiveness, the following additional factors should be considered, amongst others.

1. The size and mix of the workforce
   - The size and mix of an organization's workforce are factors that directly impact an organization's actual total compensation costs. Specifically, actual total compensation costs are a function of the average total compensation paid to employees multiplied by the number of employees employed.
   - However, if an organization's workforce is paid, on average, somewhat above the market median but is efficient in respect of its workforce planning and, as such, employs somewhat fewer employees, or an efficient mix/deployment of employees to complete the work while achieving the same business outcomes than might otherwise be the case, the actual total compensation costs may be similar to an organization whose workforce is paid at market median but utilizes a more inefficient workforce composition.
   - Thus, consideration should be given to whether an organization is being reasonably efficient in how it deploys work teams as well as its workforce composition when assessing the reasonableness of overall compensation costs. Factors such as the following could lead to being able to achieve the same work output with fewer employees: worker skill level, worker experience, work management practices, work process design, application of tools and technology, and mix of employees.
   - The mix of employees within a workforce, including the proportion of unionized employees, affects an organization's total compensation costs. Unionized populations are subject to, amongst others, collective bargaining agreements, legacy pension plans, and staffing and compensation practices that are different from non-unionized populations. The two largest employee populations at Hydro One, the Trades and Technical and Energy Professionals groups, are unionized. The mix of unionized and non-unionized employee populations and the different compensation practices used

in each group should be taken into account when assessing the reasonableness of an organization's total compensation costs.

- "Mix" of employees, in Mercer's view, has three aspects that, if prudently managed, will likely have a material impact on reducing actual total compensation costs. These three aspects are not directly captured in this Study of Hydro One's total compensation levels relative to the market median. Two of these three are the number of employees in specific jobs and the number of employees in specific employment arrangements and how they are deployed. An organization that deploys a cost effective and efficient work team to any project will generally save costs. This does not always mean using employees in the job with the lowest total compensation cost as it may be the employees in higher levels or more highly skilled jobs who can complete the work more quickly and potentially with a lower total headcount. Assuming equal productivity, using employees with lower total costs will reduce overall costs for the organization. An example of this is the routine use of "casual" workers for certain work tasks. Again, considering how the mix of employees is managed is part of assessing the reasonableness of actual total compensation costs.

2. Bargaining power of unions and essentiality of service
   - The third aspect of the mix of employees that has a material impact on actual total compensation costs is the level of unionization. Unionized workforces typically have higher total compensation costs, relative to non-unionized populations, due to their negotiating power during the collective bargaining process and their ability to threaten a work stoppage. Moreover, due to the essential nature of the services provided by the utilities industry, some organizations are likely unable to accommodate a work stoppage. This dynamic can inhibit an organization's attempt to control total compensation costs. At Hydro One, all elements of the compensation program are subject to union negotiations for the Trades and Technical and Energy Professionals groups. The comparator group established for the Study included both unionized and non-unionized organizations.

3. Cost saving benefits from increased employee morale and loyalty
   - Competitive or market-aligned compensation packages are one of the elements that can result in increased employee morale and loyalty, which in turn contribute to lower turnover rates. These lower rates can drive down talent acquisition (e.g. hiring, sourcing) and onboarding (e.g. training) costs, amongst others. In addition, lower turnover fosters knowledge retention within highly trained employees.

4. Strong track record of safety due to a highly skilled and trained workforce
   - Knowledge retention driven by low turnover rates, and consequently higher compensation levels, can produce indirect benefits, namely increased workplace safety.

When assessing the reasonableness of Hydro One's compensation costs, Mercer believes that consideration should also be given to the cost saving benefits that result from managing a highly skilled and tenured workforce.

Section 3

Guiding Principles

The guiding principles used for the Study were based on Mercer's benchmarking approach in conducting multi-year compensation benchmarking. Mercer ensures that these principles are effectively applied within the context of the Hydro One Study, making adjustments where necessary. These principles include:

1. Principle objective – to revisit the approach taken for the 2008, 2011, 2013, 2016, 2017 and 2020 Mercer Study to reasonably compare the trend of Hydro One's compensation levels to those of regulated Transmission and Distribution Utilities, Generators as well as comparable regulated businesses across Canada.
   - The 2008, 2011, 2013, 2016, 2017 and 2020 Mercer studies were conducted following the same general overall methodology to provide appropriate study-over-study comparisons.
2. Keep it simple to entice survey participants.
   - The data collection process was reviewed and streamlined, where possible, to encourage survey participants to share data. Additional follow-up was provided by Mercer to support comparator participation in the Study.
3. Be independent, testable, repeatable and market based.
   - The Study was conducted in a manner that meets each of the criteria listed.
4. Provide participants with the assurance that their information could not be attributable to them.
   - All participants were assured that data would be held confidentially by Mercer and only be shared in aggregate form.
5. Be based on the peer group and benchmark jobs surveyed in the 2020 Mercer study and adjusted based on an understanding of Hydro One's context and as deemed appropriate by Mercer.
   - The 2026 Study targeted similar benchmark jobs and organizations as the 2020 Study; however, the following updates were made:
     - The list of benchmark jobs for the 2026 Study was revised to capture the changing talent landscape and nature of the work at Hydro One. This resulted in the addition of one (1) benchmark job, totaling 32 benchmark jobs for the Study.
     - The list of peer organizations targeted to participate in the 2026 Study was updated to ensure a continued balance of Generation, Transmission and Distribution organizations, as well as comparable regulated businesses, across Canada. This resulted in a similar peer group used in the 2020 Study with the addition of five (5) regulated utility / energy organizations whose services span Generation, Transmission and Distribution.
     - Out of these five (5) organizations, two (2) participated in prior studies but elected to not participate in the 2020 Study and one (1) organization was invited to participate in the 2020 Study but declined to participate. Only one (1) organization that participated in the 2020 study declined to participate in 2026.

6. Mirror the approach in the 2008, 2011, 2013, 2016, 2017 and 2020 Mercer studies for peer selection, job classes, etc. and make only required changes deemed appropriate by Mercer.
   - Though the peer group and job list were revised, the same methodology used in 2008, 2011, 2013, 2016, 2017 and 2020 was followed in the 2026 Study for both peer company selection and the inclusion of job classes. The selected benchmark job classes for the 2026 Study represent 52% of Hydro One's regular full-time equivalents population.
7. Enable reasonable comparison to the last Mercer Study and provide a trend analysis for Hydro One.
   - By including all benchmark jobs and successfully collecting data from 95% of peers from the 2020 Study, reasonable comparisons have been made, and trending is provided.
8. Compare to market median rather than market average ("mean")
   - The Mercer Study is based on a comparison of Hydro One median compensation against market median compensation. Comparison of medians is standard compensation practice. Specifically, medians are representative of the middle data point in a sample and are less sensitive to outliers than the mean.
     - The 2008, 2011, 2013, 2016, 2017 and 2020 studies also compared Hydro One to the market median.
   - However, Appendix A provides a comparison of Hydro One's total compensation median against market average – this is something previously requested by stakeholders. On an overall weighted average basis, there is a difference between Hydro One's median positioning relative to market median and its positioning relative to the market arithmetic mean.
9. No adjustments were made to reflect regional costs of living amongst the Study participants.
10. Hydro One has relied on Mercer's expertise in conducting the Study, including recommending any appropriate changes in methodology and assumptions.

Section 4

Compensation Benchmarking

Peer Group

In addition to other factors such as industry and a regulated environment, Mercer selects peer organizations, for compensation benchmarking purposes, based on a stable metric that reflects the size and operating complexity of the organization (typically, this is revenue and/or total assets). Where there is a relatively small sample of relevant comparator organizations, Mercer generally establishes limits of 33% to 300% of the sizing scope criteria for the organization we are analyzing. Some organizations were included in the analysis despite falling outside the sizing limits in order to ensure a robust sample size. These organizations were a mix of regulated Generation, Transmission and Distribution Utilities and an Electricity System Operator that are seen as important comparators by stakeholders.

To develop a single peer group for Hydro One, Mercer initially considered all organizations, with the most recent reported annual revenues between 33% and 300% of Hydro One's 2025 annual revenue, from the following areas:

1. Electric utilities, multi-utilities, generation, transmission, and gas utilities industries in Canada
2. 60 Local Distribution Companies ("LDCs") in Ontario
3. Other comparable regulated businesses (i.e., gas pipelines, operators, etc.)

Overall, 27 organizations were invited to participate in the 2026 study:

- 24 organizations accepted the invitation and participated in the 2026 study.
  - All 20 organizations included in the 2020 study were invited to participate.
  - 19 of these 20 organizations that participated in 2020 also participated in the 2026 Study.
  - 1 organization that participated in the 2020 study declined to participate in 2026.
  - 5 additional organizations participated in the 2026 Study relative to the 2020 Study.
    - i. 2 of these organizations participated in prior studies but elected to not participate in the 2020 Study while 1 was invited to participate in the 2020 Study but declined to participate.
    - ii. Amongst the 5 organizations, AltaGas and FortisAlberta had not been invited to participate in previous studies.

Organizations that elected to not participate in the compensation benchmarking study indicated that they were unable to participate due to either resource constraints or an insufficient number of relevant benchmark jobs.

Following standard industry practice, comparisons were made between Hydro One's incumbents, at the 50th percentile, to the 50th percentile of the peer group for base salary, total cash compensation and total compensation.

To ensure that no one organization biased the results, the analysis was weighted by organization for each job class and not by number of incumbents matched to determine Hydro One's positioning relative to the market (i.e., the analysis is "Org Weighted"). To preserve the confidentiality of compensation data at both Hydro One and participating organizations, the results of the Study are presented in aggregate form.

As noted in past Mercer studies for Hydro One, Mercer has determined that comparing Hydro One to a non-utilities peer group would provide a market perspective that is not an accurate reflection of Hydro One's talent market, especially with respect to the Trades and Technical group (if it were even possible to attract participation from non-utility organizations). As such, the methodology of this Study aligns with that of previous years in that it compares Hydro One to Generation, Transmission and Distribution Utilities as well as comparable regulated businesses across Canada.

Peer Group Demographics

Summarized in Table 3 below are the participating organizations in the compensation benchmarking.

Table 3

#	Company Name	Revenue[1]	# of FTE[1,2]
1	Enbridge Inc.	$65,190.0	7,629
2	Hydro-Québec	$17,999.0	23,915
3	TC Energy Corporation	$15,200.0	3,301
4	AltaGas Ltd.*	$12,448.0	999
5	Ontario Power Generation Inc.	$7,187.0	10,352
6	British Columbia Hydro & Power Authority	$7,131.0	8,617
7	New Brunswick Power Corporation	$6,519.0	3,136
8	ATCO Ltd.	$5,143.0	6,000
9	Toronto Hydro Corporation	$3,980.0	1,399
10	Alectra Utilities Corporation	$3,622.0	1,395
11	Bruce Power L.P.	$3,500.0	5,070
12	ENMAX Corporation	$3,227.0	1,741
13	SaskPower	$3,152.2	3,679
14	Northland Power Inc.*	$2,435.0	600
15	Manitoba Hydro	$2,430.0	5,382
16	EPCOR Utilities Inc.	$2,418.1	2,937
17	Algonquin Power and Utilities Corp.	$1,767.7	2,454
18	TransAlta Corporation	$1,759.0	1,276
19	Newfoundland & Labrador Hydro	$1,350.0	1,362
20	Hydro Ottawa Limited	$1,327.5	647
21	AltaLink Management Ltd	$1,006.0	675
22	FortisAlberta Inc.*	$916.0	1,261
23	Elexicon Energy Inc.	$598.9	296
24	Independent Electricity System Operator	$230.1	1,001
75th Percentile		**$6,978.0**	**5,304**
50th Percentile		**$3,189.6**	**2,098**
25th Percentile		**$1,452.3**	**1,066**
Average		**$7,105.7**	**3,964**
Hydro One Networks Inc.		**$8,484.0**	**6,815**

[1] *Data as reported by survey participants in CAD ($MM)*

[2] *Representative of full-time equivalents only*

* *Organizations that have not participated in prior studies*

Mercer notes that, when measured on revenue, Hydro One is the fifth largest organization, for which we are able to report revenue, in the sample. Although size has a limited impact on middle management and unionized roles, size may have an impact on compensation for executive roles, as these roles tend to be larger and more complex in larger organizations.

Benchmark Jobs

The compensation survey was designed to benchmark compensation levels from a cross-section of Hydro One's workforce population. To determine the jobs to be included in the benchmark analysis, Mercer reviewed jobs that represented all of Hydro One's major business units and covered, at least, 50% of Hydro One's employee population. Mercer believes that a statistically reliable and representative sample for assessing competitive levels of total compensation (i.e. total remuneration) should contain at least 50% of the employee population.

To assist with study-over-study comparisons, it was determined that the Study should collect incumbent data using the 31 benchmark jobs surveyed in the 2020 Study. In an effort to capture the changing talent landscape and nature of the work at Hydro One, the following job has been added to the 2026 job list:

- Information Technology Manager: Added to reflect the workforce mix and addition of new IT jobs within the organization.

In total, 32 benchmark jobs were included in the 2026 Study and data is reported for all 32 jobs.

As a result, ***the 2026 Study directly reflected 3,518 Hydro One employees in 32 benchmark jobs which represent 52% of Hydro One's regular full-time equivalents population.***

In the market, Mercer collected 21,905 individual incumbent observations across the benchmark jobs (this figure excludes the 3,518 Hydro One incumbents) ***employed in the Canadian energy and/or adjacent sectors.*** This represents an increase in both the number of Hydro One employees and incumbents in comparator organizations included in the analysis, compared to the 2020 Study.

Summarized in Table 4 below are the benchmark jobs organized by major employee group. The results in this report are summarized by these employee groups.

Table 4

Hydro One Group	Job #	Benchmark Survey Title
Non-Represented	1	Financial Director
	2	Regulatory Director
	3	Manager of Construction
	4	Senior Legal Counsel
	5	Information Technology Manager*
	6	Engineer F
	7	Operations Manager
	8	Human Resource Manager / Consultant
	9	Administrative Assistant
Energy Professionals	10	Engineer E
	11	Business Analyst C
	12	Engineer D
	13	Senior Protection and Control Supervisor
	14	Estimator/Scheduler
	15	Engineer C
	16	Engineer B
	17	Business Analyst A
	18	Engineer A
Trades and Technical	19	Regional Maintainer - Lines (Supervisory)
	20	Protection and Control Technician
	21	Lineman - Journeyman
	22	Engineering Technician
	23	Regional Maintainer - Lines
	24	Regional Maintainer - Electrical
	25	Fleet Mechanic
	26	Draftsperson
	27	Stock Keeper
	28	Heavy Equipment Operator
	29	Labourer
	30	Data Entry Clerk
	31	Electrical Apprentice
	32	Lines Apprentice

**New position in 2026*

"Energy Professionals" refers to Hydro One jobs represented by the Society of United Professionals ("Society") and "Trades and Technical" predominantly refers to Hydro One jobs represented by the Power Workers' Union ("PWU" or "Power Workers").

See Appendix B for a summary of survey job descriptions.

Study Compensation Element Definition

As outlined in Appendix C, summarized below is an overview and definition of the compensation elements of the Study. Specifically:

Base Salary/Wage – Reflects annual base salary as of February 1, 2026. If an hourly rate was reported, Mercer annualized the value by multiplying the standard number of work hours per week by 52 weeks per year. If a weekly rate was reported, Mercer annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive, bonus or lump sum paid, if any.

Benefits and Pensions – To value benefit, pension and employee stock purchase plan programs, Mercer applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans.

Total Compensation – Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., share grants, long-term cash, expected value of stock options or share awards, if any) and pensions and benefits.

Study Findings

Summarized below are the results of our compensation benchmarking analysis.

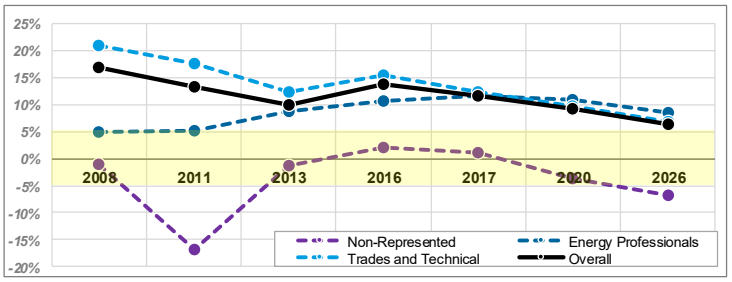
Overall, **on a weighted average basis, Hydro One's level of total compensation paid to employees is 6% above market 50th percentile / median / "P50"**. When assessing compensation competitiveness, **Mercer considers compensation to be competitive, on an overall/employee group basis, when it is within +/- 5% of the target market positioning which is the market 50th percentile for Hydro One**. Based on this, **Hydro One is positioned 1% outside the market competitive range on an overall basis.**

Hydro One is positioned above the market 50th percentile for the Energy Professionals and Trades and Technical groups – by 8% and 7% respectively. The Non-Represented group is positioned below the market 50th percentile by 7%.

In the 2020 Study, Hydro One's overall weighted average was 9% above the market 50th percentile for total compensation and 4% outside the market competitive range. Based on this, the result of the 2026 Study represents a 3% point shift towards the market median. The market competitive range has been highlighted in **yellow** in the chart below.

Table 5

			Total Remuneration (Current)													
			Variance to P50							Hydro One P50 Relative to Market P50						
	Hydro One Group	# of Hydro One Incumbents (2026)	2008	2011	2013	2016	2017	2020	**2026**	2008	2011	2013	2016	2017	2020	**2026**
Weighted Average	Non-Represented	*186*	-1%	-17%	-1%	2%	1%	-4%	**-7%**							
	Energy Professionals	*653*	5%	5%	9%	11%	12%	11%	**8%**							
	Trades and Technical	*2,679*	21%	18%	12%	16%	12%	10%	**7%**							
	Overall	***3,518***	***17%***	***13%***	***10%***	***14%***	***12%***	***9%***	***6%***							



Hydro One's trend towards the market median has been supported by a combination of factors specific to Hydro One. Some of these factors, outlined below, have had an immediate impact, while others, though implemented in the past, have a trailing impact as tenured employees at the higher end of salary ranges / wage grids and/or on legacy plans are replaced with new employees.

Immediate Impact

- An enhanced focus on broader salary management practices for the Non-Represented group
- Lower short-term incentive payouts to the Non-Represented group relative to target
- The use of a cost-effective mix of workers that have lower cost pension and benefit packages

Trailing Impacts

- The cost saving impact that reduced base salary / wage increases have on pension and benefit costs
- Some of the effects of proactive changes made to pension plans are outlined below. The full impact of these changes will be realized over time as new employees under the revised plans replace older employees under legacy benefits
  - Introduction of the Defined Contribution plan for Non-Represented employees;
  - Increased early retirement eligibility rule of 85 (up from 82) for the PWU that commenced in 2025;
  - Adjustment to number of years for final average earnings from 3 to 5 years that commenced for the PWU and Society (legacy plan) in 2025; and,
  - Employee pension contribution increases
- The natural attrition of the workforce and replacement with less costly employees

The following factors have a trailing impact and continue to hinder a faster shift towards the market median:

- Highly competitive base wages governed by collective bargaining agreements including for highly skilled Society and PWU jobs
- The relatively high value of legacy collective agreement wages, pension and benefits programs. We note that the legacy Non-Represented pension & benefit and Society pension plans are closed to new members

Mercer understands that these legacy plans (i.e. Defined Benefit plans) relate to collective agreements negotiated prior to the formation of Hydro One. All PWU employees continue to be covered by the legacy plans. Even if all Non-Represented and Energy Professional employees were covered by the new plans, though beneficial, the difference in overall competitiveness on a weighted average basis would not be as substantial as if the highly populated PWU jobs were not on the legacy Defined Benefit plan; however, the use of casual workers (“hiring hall”) for some of the Trades and Technical benchmarks does reduce compensation costs relative to other PWU jobs and our market data.

For new employees hired into Non-Represented and Energy Professional jobs, the value of pensions and/or benefits, where applicable, have decreased due to amendments to these plans (see “New” & “Go Forward” columns on the following pages). In addition to this, Hydro One also benefited from employer cost saving changes made to the legacy Energy Professionals and PWU pension plans that came into effect in 2025.

As requested by stakeholders in 2011, in addition to comparing Hydro One’s P50 to market P50, a comparison was also made of Hydro One median to market average (“mean”). On a weighted average basis, Hydro One’s total compensation is 5% above the market average. Hydro One’s position relative to market varies by employee group from 10% below market average for the Non-Represented group to 7% above the market average for the Energy Professionals group. There is a difference between Hydro One’s positioning relative to the market median and market average. However, we note that this is driven, to a certain extent, by outliers in the data set and the sample size used. See Appendix A for detailed results.

Non-Represented

Summarized in Table 6 below are the results for the Non-Represented jobs that Mercer benchmarked at Hydro One relative to the market peer group. See footnote for definitions of Current, New and Go Forward Total Compensation results.

In comparison to 2020, the 2026 Total Compensation (current) result has decreased from 4% below market 50th percentile to 7% below market 50th percentile.

Table 6

			Hydro One P50 Relative to Market P50[1]				
			Base Salary	Total Cash[2]	Total Compensation[3]		
	Hydro One Group	# of Hydro One Incumbents			Current[4]	New[5]	Go Forward[6]
Non-Represented	Financial Director	7	-14%	-12%	-3%	-3%	-10%
	Regulatory Director	7	-16%	-19%	-11%	-11%	-18%
	Manager of Construction	8	8%	17%	19%	19%	9%
	Senior Legal Counsel	4	-7%	-6%	-5%	-5%	-9%
	Engineer F	39	-10%	-17%	-7%	-8%	-14%
	Operations Manager	79	-10%	-16%	-11%	-11%	-14%
	Human Resource Manager / Consultant	10	-31%	-32%	-33%	-33%	-33%
	Information Technology Manager	25	5%	8%	7%	7%	3%
	Administrative Assistant	7	5%	6%	2%	2%	2%
	2026 Weighted Average Non-Represented	186	-8%	-12%	-7%	-7%	-11%
	2020 Weighted Average Non-Represented	155	-7%	-5%	-4%	-4%	-10%
	2017 Weighted Average Non-Represented	172	-6%	-3%	1%	0%	-12%
	2016 Weighted Average Non-Represented	167	-1%	-3%	2%	-1%	-12%
	2013 Weighted Average Non-Represented	206	-2%	-4%	-1%	-6%	-
	2011 Weighted Average Non-Represented	137	-17%	-20%	-17%	-18%	-
	2008 Weighted Average Non-Represented	151	-2%	-4%	-1%	-5%	-

[1] Market data is weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.).
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents are on the new DB pension and benefits programs.
[6] Based on Hydro One's employee population, assuming all incumbents are on the new DC pension and benefits programs.

Energy Professionals ("Society")

Summarized in Table 7 below are the results for the Energy Professional jobs that Mercer benchmarked at Hydro One relative to the market peer group.

In comparison to 2020, the 2026 Total Compensation (Current) result has decreased from 11% above market 50th percentile to 8% above market 50th percentile. For the Energy Professionals employee group, Go Forward Total Compensation results are the same as New and therefore not repeated in table 7 below.

Table 7

			Hydro One P50 Relative to Market P50[1]			
					Total Compensation[3]	
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Current[4]	New[5]
Energy Professionals	Engineer E	29	4%	-5%	2%	2%
	Business Analyst C	3	11%	4%	13%	13%
	Engineer D	398	3%	-9%	2%	2%
	Senior Protection and Control Supervisor	29	6%	-1%	11%	11%
	Estimator/Scheduler	32	21%	17%	27%	27%
	Engineer C	33	4%	-1%	9%	9%
	Engineer B	62	18%	9%	23%	23%
	Business Analyst A	17	29%	23%	30%	30%
	Engineer A	50	12%	8%	20%	20%
	2026 Weighted Average Energy Professionals	653	7%	-3%	8%	8%
	2020 Weighted Average Energy Professionals	400	9%	3%	11%	11%
	2017 Weighted Average Energy Professionals	560	5%	3%	12%	11%
	2016 Weighted Average Energy Professionals	612	5%	1%	11%	10%
	2013 Weighted Average Energy Professionals	746	7%	3%	9%	7%
	2011 Weighted Average Energy Professionals	779	6%	-3%	5%	4%
	2008 Weighted Average Energy Professionals	578	8%	-2%	5%	3%

[1] Market data is weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.).
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents are on the new pension and benefits programs.

Trades and Technical

Summarized in Table 8 below are the results for the Trades and Technical jobs that Mercer benchmarked at Hydro One relative to the market peer group. In comparison to 2020, the 2026 Total Compensation result has decreased from 10% above market 50th percentile to 7% above market 50th percentile. New and Go Forward Total Compensation results are the same as Current, as there is only one legacy Defined Benefits plan for the Trades and Technical employee group.

Table 8

			Hydro One P50 Relative to Market P50[1]		
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Total Compensation[3] Current[4]
Trades and Technical	Regional Maintainer - Lines (Supervisory)	171	1%	-2%	10%
	Protection and Control Technician	135	20%	19%	26%
	Lineman - Journeyman	130	-10%	-10%	-12%
	Engineering Technician	182	11%	8%	20%
	Regional Maintainer - Lines	939	-5%	-5%	2%
	Regional Maintainer - Electrical	248	12%	12%	22%
	Fleet Mechanic	94	9%	9%	20%
	Draftsperson	22	18%	14%	24%
	Stock Keeper	72	22%	18%	31%
	Heavy Equipment Operator	55	14%	14%	16%
	Labourer	120	7%	1%	16%
	Data Entry Clerk	36	13%	10%	22%
	Electrical Apprentice	125	-14%	-14%	-8%
	Lines Apprentice	350	-11%	-11%	-10%
	2026 Weighted Average Trades and Technical	2,679	0%	-1%	7%
	2020 Weighted Average Trades and Technical	2,801	2%	1%	10%
	2017 Weighted Average Trades and Technical	2,478	3%	1%	12%
	2016 Weighted Average Trades and Technical	2,212	5%	4%	16%
	2013 Weighted Average Trades and Technical	2,100	8%	6%	12%
	2011 Weighted Average Trades and Technical	2,411	10%	9%	18%
	2008 Weighted Average Trades and Technical	1,966	20%	16%	21%

[1] Market data is weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.).
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.

Section 5

Overtime Policy Benchmarking

Mercer has compared Hydro One's overtime policy to the overtime policies found in the comparator group. By doing this, Mercer is able to make a direct comparison of how aligned Hydro One's overtime policy is relative to policies in peer organizations. Below are Mercer's findings from the review:

i) **Overtime Rate:** Similar to the findings from the 2020 overtime policy review, across all overtime types (e.g. weekdays, weekends, call outs, etc.) Hydro One's overtime rates continue to be at or below the market median.

ii) **Tiered Rate:** Where tiered rates are used, though Hydro One is aligned with the most prevalent tier rate range of 1.5x – 2x, the amount of hours worked that Hydro One requires to move to the next overtime rate tier (e.g. 1.5x for first 2 hours and 2x afterwards), is lower than the market median. Specifically, Hydro One switches to a higher tier after 2 hours whereas the market median is 4 hours.

iii) **Minimum Hours for Standard Overtime:** Hydro One is aligned with the predominant market practice of offering minimum overtime hours to employees. That said, 60% of Hydro One's unions reviewed have a minimum number of hours that is higher than the most prevalent amount provided within the peer group.

iv) **Overtime Tracking and Approval Process:** Hydro One's overtime tracking and approval process continue to be aligned with predominant market practice.

The table below presents the prevalence of overtime pay rates across different overtime types for Hydro One and the comparator group. The most prevalent overtime rate for each category is highlighted in **blue**. The 1.5x – 2x range reflects instances where a tiered approach for overtime is utilized (e.g. 1.5x for the first 2 hours and 2x onwards). We note that Hydro One's overtime rates vary across the different union groups within the organization. However, the minimum overtime rate present within the organization is 1.5x up to a maximum 2x. **Standard** represents overtime from working beyond the established standard hours for a job. **Call out** represents instance within which an employee is unexpectedly required to go back to work after they have already left for the day. Weekend, statutory holiday and vacation overtime represent overtime incurred on those specific types of days.

Table 9

	Pay Rate Across Overtime Types					
	Pay Rate	Standard	Call Out	Weekend	Statutory Holiday	Vacation
Market	1.5x	9%	9%	9%	5%	9%
	1.5x - 2x	23%	18%	14%	14%	14%
	2x	**64%**	**73%**	**77%**	**77%**	**77%**
	2x - 2.5x	0%	0%	0%	5%	0%
	2x - 3x	5%	0%	0%	0%	0%
Hydro One	1.5x	20%	20%	0%	0%	20%
	1.5x - 2x	**40%**	**40%**	20%	0%	20%
	2x	**40%**	**40%**	**80%**	**100%**	**60%**
	2x - 2.5x	0%	0%	0%	0%	0%
	2x - 3x	0%	0%	0%	0%	0%

Mercer does not include overtime costs when conducting benchmarking exercises due to the variability of the inputs that are required to determine these values. Specifically, overtime values use inputs, namely the number of overtime hours worked, that are volatile and specific to organizations. Overtime may also be impacted by the geographical area an organization services (remote vs dense areas), “acts of god” on operations (e.g. winter storms) and general service requirements (e.g. customer demand). These inputs are challenging to normalize across Hydro One’s peer group for the Study; as such, market positioning results are unlikely to be representative of the reasonableness of overtime costs at Hydro One. In addition, reliable actual paid overtime data for individual employees is very difficult to collect and validate in a total compensation study.

Similarly, Mercer does not include contractors in benchmarking studies due to the unique compensation arrangements that govern them. Including contractors may impact the Study’s ability to accurately assess the degree of competitiveness of Hydro One’s total compensation levels.

Section 6

Short-Term Incentive Plan and Long-Term Incentive Plan Benchmarking

Across all comparator organizations that provided data for a Non-Represented benchmark job, 83% provide STI to their employees while 46% provide LTI. Hydro One is aligned with the market in that LTI is generally more prevalent at senior level jobs and in publicly traded organizations**.** This reflects senior level job's ability to better influence long-term business results.

Hydro One is generally aligned with the market prevalence in that all Non-Represented jobs are eligible for STI while only the Director level jobs in the benchmark job list (2 jobs) are eligible for LTI.

Appendix A

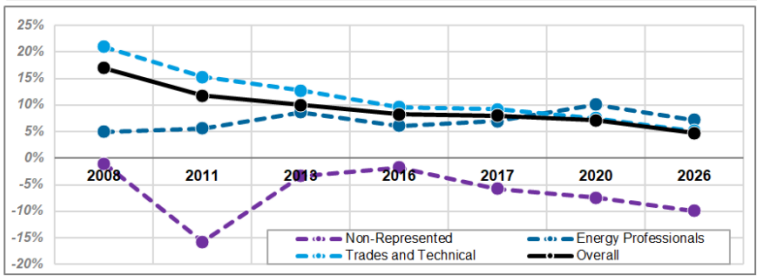
Hydro One vs. Market Average

As was previously requested by stakeholders in 2011, and has been provided in Study updates since then, summarized in Table 10 below are the results of our compensation benchmarking analysis comparing Hydro One median to market average.

Overall, **on a weighted average basis, Hydro One's total compensation cost is 5% above the market average (mean)**. Hydro One's position relative to market varies by employee group from 10% below the market average for the Non-Represented group to 7% above the market average for the Energy Professionals group.

Table 10

			Total Remuneration (Current)													
			Variance to Market Average							Hydro One P50 Relative to Market Average						
	Hydro One Group	# of Hydro One Incumbents (2026)	2008	2011	2013	2016	2017	2020	**2026**	2008	2011	2013	2016	2017	2020	**2026**
Weighted Average	Non-Represented	*186*	-1%	-16%	-3%	-2%	-6%	-7%	**-10%**							
	Energy Professionals	*653*	5%	6%	9%	6%	7%	10%	**7%**							
	Trades and Technical	*2,679*	21%	15%	13%	10%	9%	8%	**5%**							
	Overall	***3,518***	***17%***	***12%***	***10%***	***8%***	***8%***	***7%***	***5%***							



Non-Represented

Summarized in Table 11 below are the results for the Non-Represented jobs that Mercer benchmarked at Hydro One relative to the market peer group.

Table 11

			Hydro One P50 Relative to Market Average[1]				
			Base Salary	Total Cash[2]	Total Compensation[3]		
	Hydro One Group	# of Hydro One Incumbents			Current[4]	New[5]	Go Forward[6]
Non-Represented	Financial Director	7	-12%	-12%	-6%	-6%	-13%
	Regulatory Director	7	-12%	-17%	-11%	-11%	-18%
	Manager of Construction	8	8%	11%	16%	16%	6%
	Senior Legal Counsel	4	-9%	-7%	-6%	-6%	-11%
	Engineer F	39	-12%	-15%	-12%	-13%	-19%
	Operations Manager	79	-9%	-15%	-15%	-15%	-18%
	Human Resource Manager / Consultant	10	-31%	-34%	-35%	-35%	-35%
	Information Technology Manager	25	7%	8%	8%	8%	4%
	Administrative Assistant	7	-1%	2%	0%	0%	0%
	2026 Weighted Average Non-Represented	186	-8%	-11%	-10%	-10%	-14%
	2020 Weighted Average Non-Represented	155	-7%	-9%	-7%	-8%	-14%
	2017 Weighted Average Non-Represented	172	-8%	-9%	-6%	-7%	-18%
	2016 Weighted Average Non-Represented	167	-2%	-5%	-2%	-5%	-16%
	2013 Weighted Average Non-Represented	206	-4%	-6%	-3%	-8%	-
	2011 Weighted Average Non-Represented	137	-15%	-17%	-16%	-17%	-

[1] Market data is weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.).
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents are on the new DB pension and benefits programs.
[6] Based on Hydro One's employee population, assuming all incumbents are on the new DC pension and benefits programs.

Energy Professionals ("Society")

Summarized in Table 12 below are the results for the Energy Professional jobs that Mercer benchmarked at Hydro One relative to the market peer group.

Table 12

			Hydro One P50 Relative to Market Average[1]			
			Base Salary	Total Cash[2]	Total Compensation[3]	
	Hydro One Group	# of Hydro One Incumbents			Current[4]	New[5]
Energy Professionals	Engineer E	29	2%	-8%	1%	1%
	Business Analyst C	3	7%	1%	10%	10%
	Engineer D	398	2%	-6%	3%	3%
	Senior Protection and Control Supervisor	29	6%	1%	9%	9%
	Estimator/Scheduler	32	18%	11%	21%	21%
	Engineer C	33	4%	-3%	5%	5%
	Engineer B	62	17%	11%	21%	21%
	Business Analyst A	17	24%	19%	27%	27%
	Engineer A	50	8%	3%	12%	12%
	2026 Weighted Average Energy Professionals	653	6%	-2%	7%	7%
	2020 Weighted Average Energy Professionals	400	7%	1%	10%	10%
	2017 Weighted Average Energy Professionals	560	5%	1%	7%	6%
	2016 Weighted Average Energy Professionals	612	7%	-1%	6%	5%
	2013 Weighted Average Energy Professionals	746	8%	1%	9%	7%
	2011 Weighted Average Energy Professionals	779	6%	-1%	6%	4%

[1] Market data is weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.).
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.
[5] Based on Hydro One's employee population, assuming all incumbents are on the new pension and benefits programs.

Trades and Technical

Summarized in Table 13 below are the results for the Trades and Technical jobs that Mercer benchmarked at Hydro One relative to the market peer group.

Table 13

			Hydro One P50 Relative to Market Average[1]		
	Hydro One Group	# of Hydro One Incumbents	Base Salary	Total Cash[2]	Total Compensation[3] Current[4]
Trades and Technical	Regional Maintainer - Lines (Supervisory)	171	-4%	-9%	4%
	Protection and Control Technician	135	16%	12%	24%
	Lineman - Journeyman	130	-14%	-16%	-14%
	Engineering Technician	182	11%	7%	19%
	Regional Maintainer - Lines	939	-7%	-10%	3%
	Regional Maintainer - Electrical	248	5%	1%	14%
	Fleet Mechanic	94	5%	2%	14%
	Draftsperson	22	22%	18%	30%
	Stock Keeper	72	18%	15%	26%
	Heavy Equipment Operator	55	3%	1%	6%
	Labourer	120	3%	1%	6%
	Data Entry Clerk	36	14%	11%	24%
	Electrical Apprentice	125	-16%	-17%	-10%
	Lines Apprentice	350	-9%	-11%	-9%
	2026 Weighted Average Trades and Technical	2,679	-2%	-5%	5%
	2020 Weighted Average Trades and Technical	2,801	1%	0%	8%
	2017 Weighted Average Trades and Technical	2,478	2%	0%	9%
	2016 Weighted Average Trades and Technical	2,212	2%	-1%	10%
	2013 Weighted Average Trades and Technical	2,100	9%	7%	13%
	2011 Weighted Average Trades and Technical	2,411	10%	8%	15%

[1] Market data is weighted by organization (i.e., for each participating organization, Mercer determined one average value per job.).
[2] Base salary plus short-term incentives granted (i.e., bonus), where applicable.
[3] Total cash compensation plus estimated long-term incentives, benefits and pension values.
[4] Based on Hydro One's employee population, assuming current pension and benefits program eligibility.

APPENDIX B

Survey Job Descriptions

Job #	Benchmark Survey Title	Generic Description
1	**Administrative Assistant**	Requires a general knowledge of departmental procedures, practices and office routine. Possesses good office and computer skills including word processing, spreadsheets, graphics software, and filing.
2	**Business Analyst A**	Assists with analyzing internal metrics. Performs responsible and varied business analytical or administrative functions. Assists with preparation documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree and up to 2 years experience.
3	**Business Analyst C**	Analyzes internal metrics. Performs responsible and varied business analytical or administrative functions. Prepares documents, forecast summaries, status reports, budget reports, etc. Duties may include interpreting and processing company contracts, AFEs, and government agreements. Assignments are given in terms of objectives and relative priorities. Problems may be solved by adapting standard methods or by practical applications of knowledge. Usual qualifications include a university degree with a minimum of 4 years' related experience.
4	**Data Entry Clerk**	Perform data processing services including inputting, updating, to various computerized databases and applications of external service providers. Perform clerical/administrative duties in support of system processes. Work with various internal and external contacts and customers in the set up, maintenance, reporting and follow up of non-electricity accounts, customer service orders, materials, corporate charge cards, time reporting, management reporting, damage claims, accounts receivable, etc. Perform administrative services for provincial client group and special projects.
5	**Draftsperson**	Incumbent works on standard drafting assignments. Methods are detailed and standard but judgment is required in planning tasks and choice of methods. Accountable for accuracy and adequacy of work performed. May provide technical guidance to less experienced Drafters. Usual qualifications include a technical school diploma or equivalent, with a minimum of 5 years' related experience.
6	**Electrical Apprentice**	A five year apprenticeship leading to a Construction and Maintenance Electrician.
7	**Engineer A**	Incumbent receives "on-the-job" training in various phases of office, plant or field engineering through assignments or, in some cases, classroom instruction. Tasks assigned are simple and routine in nature. Assists more senior engineers in the preparation of plans, calculations, reports, etc. Few technical decisions are made and these are routine, with clearly defined procedures and guidelines. Works under close supervision and work is reviewed for accuracy, adequacy and conformance with prescribed procedures. Usual qualifications include a university degree in engineering with minimal experience. Incumbents in this job are not required to hold an engineering license in Ontario.

Job #	Benchmark Survey Title	Generic Description
8	**Engineer B**	Uses a variety of standard problem solving techniques. May assist more senior engineers in carrying out technical tasks requiring computation methods. Duties are assigned with detailed oral, and occasionally written instructions. Work is reviewed in detail with guidance given. May give limited technical guidance to junior professionals or technicians working on a common project. Usual qualifications include a university degree in engineering with a minimum of 2 years' related experience. The candidate will usually obtain their license through the course of this work and from then on, they will seal their work as a professional engineer. This candidate may also work independently on less complex projects.
9	**Engineer C**	Incumbent is responsible for varied engineering assignments requiring a broad knowledge of an engineering specialty and the effect the work has upon other fields. Solves problems using a combination of standard or modified procedures. Participates in planning objectives. Performs independent studies, and analyzes, interprets and draws own conclusions; more complex work projects are referred to more senior authorities. Not supervised in detail except on more difficult assignments. May give periodic technical guidance to less experienced professionals or technicians assigned to work on a common project. Typical qualifications include a university degree in engineering with a minimum of 4 years' related experience.
10	**Engineer D**	This is the first level of full engineering specialization and is considered the senior level position. Alternatively may be the level at which an individual acts as group leader or work task force leader of a small group of technical personnel. Requires application of well developed technical knowledge in planning, conducting and coordinating difficult assignments. The position requires the modification of established guidelines and initiation of new approaches. Makes independent decisions in planning, organizing and completing technical assignments. Work is reviewed for soundness of judgement but accepted technically as accurate and feasible. Work is assigned in terms of objectives and priorities but informed guidance is available. Advises on technical problems and supervision, and may plan, schedule and review work of professional engineers and technicians. Incumbent must have an engineering license. The candidate will seal all their work and may also seal the work of junior staff who work under their supervision where the junior staff do not yet have their license. This candidate may be asked to be a Subject Matter Expert when reviewing outsourced work.
11	**Engineer E**	May have responsibility for coordinating engineering work assignments and making recommendations on technical applications developed by other professional personnel or consultants . May involve the direct supervision of a group of professionals. Provides guidance and training to less experienced staff. Checks work for accuracy and completeness. As a specialist, conducts special, complex and advanced level studies. Work is generally reviewed for results only. Makes independent decisions within broad guidelines and policies. Incumbent must have an engineering license. The candidate will seal all their work and may also seal the work of junior staff who work under their supervision where the junior staff do not yet have their license. This candidate may be asked to be a Subject Matter Expert when reviewing outsourced work.

Job #	Benchmark Survey Title	Generic Description
12	**Engineer F**	Incumbent is considered an authority in an engineering field of specialization and acts as a technical consultant to the organization. This level is a dual-stream first level managerial position. Incumbents may be responsible for directing a staff of professional and support employees or act as a technical specialist. Responsible for planning and directing large engineering programs/projects; sets priorities and allocates resources; makes necessary decisions on all day-to-day operating matters within constraints of company policy. Receives work in terms of broad objectives. Usual qualifications include over 15 years experience.
13	**Engineering Technician**	Perform technical support work for the Distribution: such as monitoring the performance of the distribution. Negotiate property settlements on distribution/transmission lines and perform joint use activities. Provide administrative support related to preparation of estimates and work orders (WO) work schedules, line layouts, joint use, provision of underground cable and fault location service. Perform staking activities and prepare design packages for new connections, service upgrades, extensions, betterments and relocations.
14	**Estimator/Scheduler**	Supervise and direct the work operations of a group engaged in the preparation of capital construction projects, release and study estimates and schedules, construction cost estimates an cost reporting systems.
15	**Financial Director**	Responsible for providing overall direction for tax, insurance, budget, credit and treasury functions for the organization. Provide short to medium term direction for all corporate financial functions so that financial transactions, policies, and procedures meet the organization's short and medium-term business objectives and are conducted in accordance with regulations, and standards. Activities may include: credit control; cash flow; investment management; tax; insurance; treasury; internal audit; budgeting and forecasting; and foreign exchange. Lead, direct, evaluate, and develop a team of senior managers to ensure that the organization's financial strategy is implemented effectively, consistently and according to established guidelines.
16	**Fleet Mechanic**	Regional Field Mechanic is responsible for the scheduled inspection, repair and maintenance, as well as emergency repair of Transport and Work Equipment (e.g. on and off-road tracked bucket machines, digger derricks, cranes, Manlifts, forklifts, backhoes, muskeg tractors, excavators, highway tractors, floats, trailers, pullers/tensioners, vans/pick-up trucks), and the hydraulic equipment on the vehicles (e.g. booms, buckets). Job duties also include maintaining inspection schedules and coordinating/scheduling repairs to be completed or contracted out. Work is performed in a garage &/or on site.
17	**Heavy Equipment Operator**	Equipment Operators are operators of heavy earth moving construction equipment such as bulldozers, front-end loaders, forklifts, excavators backhoes, tension pulling machines, equipment for pole hold drilling and Hydro Vac excavation trucks etc. Generally assist both lines and stations crews. Under lines construction often operate and drive various types of cranes and boom trucks and must hold and maintain the required license(s) such as AZ, 339C, 339A based on the equipment being operated/driven. Operating Engineers/Heavy Duty Mechanics are trained to repair and maintain many types of heavy equipment.

Job #	Benchmark Survey Title	Generic Description
18	**Human Resource Manager / Consultant**	This position leads the planning, design, development, implementation, and administration of HR policies and programs across areas such as employee relations, compensation, job evaluation, performance management, recruitment, and employment equity/human rights. It provides managerial oversight and functional supervision to HR staff, offering coaching, guidance, and operational leadership to ensure consistent, effective delivery of HR services. Typically requiring 3–5 years of progressive HR experience, this role partners with leaders to support organizational objectives, ensure legislative compliance, and enhance employee and workplace effectiveness.
19	**Information Technology Manager**	Oversee the organization's technology infrastructure including hardware, software, networks, and core business systems while leading the IT team to ensure secure, reliable, and efficient operations. This role is accountable for maintaining, upgrading, and protecting critical platforms (e.g., servers, networks, email, and applications), recruiting and developing IT staff, and translating business needs into practical IT strategies, policies, and procedures. Responsibilities also include safeguarding data integrity and network security through controls such as firewalls, backups, and disaster recovery planning; managing the IT budget; overseeing vendor relationships and contract negotiations; and driving IT projects from planning through delivery to support business goals. Bachelor's degree in computer science, information technology, or a related field is required; proven IT management and team leadership experience; strong knowledge of infrastructure and security; and demonstrated project management, problem-solving, and communication skills. Relevant certifications (as applicable) may include PMP, CISSP, and/or ITIL.
20	**Labourer**	Performs general labour work & assists other construction trades as required. The work involves material handling; hand excavation/backfill; operating equipment; demolition of structures including jack hammering to break up concrete; operating small tools; intermittent tractor/forklift/Bobcat operation; janitorial tasks, flagging, traffic control, equipment monitoring; assisting with formwork, scaffold erection/dismantling; and other miscellaneous labour related tasks as required.
21	**Lineman - Journeyman**	Responsible for the installation, maintenance, removal, and inspection of transmission/distribution power lines. Requires 4 years of experience and certification as a Power Line Technician (or equivalent), with 4 years experience/8000 hours, and is red seal certified. Entails on-call work and working at 300 feet, interacting with customers and the public.
22	**Lines Apprentice**	A four year apprenticeship leading to a Power Line Technician position.
23	**Manager of Construction**	Responsible for providing construction management and supervision within the construction group. Administers construction contracts. Is accountable for construction costs, schedules, safety, product quality and environment performance. Provides input into Project Execution Plans and the associated schedules and estimates. Usual qualifications include 10 to 12 years of experience including supervisory experience. Requires experience in construction management and supervision of various trades.

Job #	Benchmark Survey Title	Generic Description
24	**Operations Manager**	Manage and supervise trade, technical and clerical staff. Develop work programs, organize schedules, provide instructions, guidance and checks, monitor work to ensure work quality and accuracy and in conformity to governing regulations. Ensure the administration of procedures, applicable legislation and collective agreements are met. Administer and control contract work . Review work methods, ensure appropriate training. Develops, maintains and enhance customer relationships through direct contact both internally and externally. This position is non-represented. Areas of accountability could be managing staff responsible for operating transmission or distribution systems, the execution of protection, control and station maintenance work programs or managing staff responsible for electrical services such as new connections/upgrades, trouble call/storm restoration or forestry work programs.
25	**Protection and Control Technician**	Perform initial inspections, conduct trouble-shooting and preventative maintenance, carry out modifications and repairs as required, on all types of protection, telecommunications, metering and control equipment which comes under Protection and Control (P&C) jurisdiction. Discuss and review results with supervisor, if the equipment is highly critical from the standpoint of system operation, before putting the equipment into service.
26	**Regional Maintainer - Electrical**	Responsible for the general maintenance and repair work on electrical systems and equipment at various geographical locations. Requires overhauling, maintaining and inspecting equipment such as conductors & insulators i.e. batteries, station bus, cable, compressed air systems, fire protection equipment switchgear i.e. circuit breakers, load interrupters metalclad switchgear, oil circuit breakers, SF6 breakers, air blast breakers, transformers, rotating machines, distribution stations & equipment. Has the necessary knowledge of the trade theory, operating principles, charts, tables, testing equipment and other reference works, to test, dismantle, repair, clean and assemble station electrical equipment within the required specifications. Requires certification as a construction and maintenance electrician (309A, 2200 hours). Also performs mechanical and protection and control work.
27	**Regional Maintainer - Lines**	Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Understands and is able to operate the tools of his/her trade, and is familiar with the various instruments, i.e. voltmeters, ammeters and ohmmeters. Must be familiar with hydraulically-operated articulated or telescopic aerial devices. Must provide at own expense any tools listed for the classification if required in his/her work in accordance with the attached tool list. This classification also includes the requirement to hold a Power Line Technician certification (or equivalent), with 4 years experience/8000 hours, and is red seal certified. Entails on-call work and working at 300 feet, interacting with customers and the public. The job will assume Lead Hand duties, as required.
28	**Regional Maintainer - Lines (Supervisory)**	This position is responsible for the safety, quality and quantity of the work performed by his/her crew (three or more Regional Maintainers-Lines/Linespersons). They plan work including staffing requirements, assigning work, co-ordinate work with other work groups, ensure proper work practices are followed, report on work performed and engage in good public relations. He/she performs the following physical work activities. Construct and maintain transmission and distribution lines and associated apparatus. Maintain power service to electrical customers. Also responsible for contract monitoring and lead hand responsibilities.

Job #	Benchmark Survey Title	Generic Description
29	**Regulatory Director**	Executive with primary responsibility for preparing, managing, and leading company's testimony in utilities rate cases before local, regional or federal agencies. Responsibilities include development of all research associated with regulatory activities including activity across other regulatory entities and maintaining relationship with all regulators. Develops cost factors in association with utilities rate cases, may or may not, be involved in delivery of testimony.
30	**Senior Legal Counsel**	Responsible for providing management and employees with advice on a broad range of moderately complex conflicting legal principles. The applicable laws and regulations are numerous and varied, and present difficult problems of interpretation. Applies independent judgement in recommending a course of action for a client department, providing input as to the ramifications of a course of action, a legal decision, or a new piece of legislation. Usual qualifications include a law degree, membership in a law society/bar association and/or other relevant jurisdiction with a minimum of 8 year's related experience.
31	**Senior Protection and Control Supervisor**	Provide advice and guidance to field and support groups on matters related to the work programs such as protection, instrumentation, control and telecommunications pertaining to the protection, operations, control and maintenance of the electrical power system. Also may participate in the development of standards and procedures. Minimum of 8 years experience. Supervise staff engaged in the inspection and testing of electrical equipment to verify the equipment meets specified requirements and regulations.
32	**Stock Keeper**	Receives, receipts, stores, inventories, issues and ships materiel used in operations. Manages materiel, in accordance with established practices and regulations. Is responsible for materiel under his/her control. Performs maintenance, not requiring formal trades qualifications, and assists in tasks where unskilled or semi-skilled ability is required. Operates transport and work equipment.

APPENDIX C

Detailed Compensation Benchmarking Definition and Methodology

Summarized in this appendix are supporting descriptions of how Mercer determined values for each of the major components of compensation. Specifically:

Base Salary/Wage – Annual base salary at February 1, 2026. If an hourly rate was reported, Mercer annualized the value by multiplying the standard number of hours per week by 52 weeks per year. If a weekly rate was reported, Mercer annualized the value by multiplying by 52 weeks per year.

Total Cash Compensation - Base salary ***plus*** most recent short-term incentive, bonus or lump sum paid, if any.

Benefits and Pensions – To value benefit, pension and employee stock purchase plan programs, Mercer applied a relative value process to a set of standard employer paid cost factors, plus actuarial and demographic assumptions to measure all financially significant features of benefit and pension programs based on open and closed plans. See detailed methodology below.

Total Compensation - Total cash compensation ***plus*** estimated annual value of the most recent long-term incentive grant (i.e., share grants, long-term cash, expected value of stock options or share awards, if any) and pensions and benefits.

Detailed Benefits and Pension Methodology – Total remuneration includes the following values for benefits and pensions:

- Mercer's relative value process applies a broad set of standard cost factors, plus actuarial and demographic assumptions to measure all of the financially significant features of benefit programs on a benefit line basis.
- Effectively, this process isolates the plan design and removes variable factors such as historical experience, demographics, and utilization trends specific to each participant in the study. For example, if two survey participants have an identical benefit offering, the values will be equal regardless of the actual plan costs to each of the employers.

Aligning Values with Hydro One's Actual Costs

Participation & Anti-Selection:

Active Flex Benefits:

- Participation: Mercer uses a standardized set of participation assumptions for all participants that vary only by the number of options that are offered under the plan. Therefore, two identical flex programs will produce similar relative Total Values.
- Anti-Selection: A unique feature of flex plans is that employees who choose richer options are likely to be higher claimers than those choosing poorer options. This is reflected within our methodology by increasing the value of the richer options and reducing the value of the poorer options. The final relative values of the flex plan are a weighted average of the values of each of the options.
- Optional plans that are fully employee-paid (such as optional life) are excluded from the review.
- Low value core plans / catastrophic core plans and spousal top-up plans are excluded from the valuation.

Projection Methodology for Pension Plans

Defined Benefit Plans

- For defined benefit plans, the expected present value of future pension accruals is calculated using the retirement and termination scales and each company's plan design, at various earnings levels, using a common employee population profile. The future value of pension accruals were converted into company provided values by deducting any required employee contributions under each plan. The resulting company provided values were expressed as a percentage of earnings to be applied to the earnings associated with each benchmark job.

Defined Contribution Plans

- For defined contribution benefit plans, plan value is modelled over a typical career and reflected as a percentage of career earnings, in particular for service and points related plans.
- Where employees are entitled to choose the level of their contributions, employees were assumed to contribute at the level that would maximize company contributions.
- Company provided values are determined by deducting any employee contributions under each plan.

Projection Methodology for Post-Retirement Non-Pension ("PRNP")

Employee-specific factors including earnings and service are projected to each of the assumed retirement ages at which point the benefit payable is determined, actuarially valued and discounted with interest to the current age of the employee. The resulting values are split pro-rata on service into the benefit in respect of past service and the benefit in respect of future service, and the future service benefit value is converted to a level percentage of future pensionable earnings.

- The results are weighted by the assumed retirement rates and combined to produce a single value of future benefit accruals, as a percentage of future earnings, per member.
- Benefits are projected both before and after retirement based on benefit-specific (e.g. medical, dental) inflation assumptions.
- Benefits are coordinated with provincial medical and drug plans.
- Lifetime maximums are reflected where applicable.

Flex Premium Cost Sharing & Credit Allocation:

- Cost sharing is determined using each participant's actual price tag and credit formula.
- Assumptions are made as to where credits would commonly be used, unless they are allocated to specific benefits. These assumptions coordinate with the standardized participation assumptions outlined earlier.

Standard Demographic Assumptions:

- A common population reflecting the general demographics of a Canadian workforce group and adjusted to more closely mirror the Hydro One's workforce used in the analysis.
  - This population reflects a group of employees with an average age of 41 and average service of 12 years.
- For Pension and Post Retirement Non-Pension benefits, the retirement scale for the population is as follows:
  - 25% retirement at age 55
  - 55% retirement at age 60
  - 100% retirement at age 65
  - 70% of the active members are assumed to be married over their career while 90% of members are assumed to be married at the time of their retirement

Other Actuarial Assumptions:

- The following assumptions were used in the review:
  - Discount rate: 5.00% per annum
  - Inflation: 2.00% per annum
  - YMPE Increase: 3.00% per annum
  - Salary Increase: 4.00% per annum
  - Post Retirement mortality: 95% of CPM 2014 Private Sector Mortality projected with CPM-B Scale
  - Termination rates of 1% each year prior to age 55 (for pension values)
  - Medical and Dental inflation/utilization increases

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HYDRO ONE INC.

Management Compensation Benchmarking Study

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July 2026

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Introduction

Assessment and Segmentation

- Hydro One has engaged Willis Towers Watson ("WTW") to conduct a competitive assessment of its compensation structure relative to market for all management employees (excluding CEO and direct reports)
- This review is based on Target Total Direct Compensation (TTDC), defined as salary range midpoint + target bonus + target long-term incentives (if applicable)
- For benchmarking compensation, Hydro One has taken a segmented approach and uses three different segmented peer groups to better align with the underlying labour market of each segment:
  - Executives (116 peer companies)
  - Operations (52 peer companies)
  - Core Services (334 peer companies)

Segment	Total # of Hydro One Incumbents		Total Incumbents in Benchmark Roles	
	Employee Count[1]	% of Management Distribution	Employee Count[1,2]	% Benchmarked
Executives *(Level 8 - 10)*	34	4%	26	76%
Operations (Levels 4 - 7)	358	40%	296	83%
Core Services[3] (Levels 1 - 7)	494	56%	456	92%
Overall	**886**	**100%**	**778**	**88%**

The compensation benchmarking analysis reflects results for over 88% of the population, a robust sample size that is reflective of the entire population.

1. Excludes any incumbents with "INACTIVE" status (e.g., employees on leave of absence)
2. Represents incumbents with sufficient competitive market data
3. Reflects Core Services and Core Services Premium segments

Refer to pages 6 and 7 for segment definitions and a summary of all peer group selection criteria. Refer to **Appendix I** for detailed peer group listings

Introduction

Overall Results

- Overall, by weighted average, Hydro One's Target Total Direct Compensation (TTDC) is positioned at the market 50th percentile
- Positioning varies by segment and level
- Additional details on positioning by segment and level are provided on pages 11 to 15

Segment	Number of Incumbents Benchmarked	Hydro One Target Compensation Positioning vs 50th Percentile		
		Salary Range Midpoint vs Market P50	Target Total Cash (TTC) vs Market P50	Target Total Direct Compensation (TTDC) vs Market P50
Executive	26	-9%	-8%	-5%
Operations[1]	296	-2%	-2%	-5%
Core Services[1,2]	456	0%	2%	3%
Overall[3]	778	-1%	0%	0%

1. Operations and Core Services positioning excludes levels 8-10
2. Reflects Core Services and Core Services Premium segments
3. Represents incumbent weighted results across all segments

Methodology

Segment Definitions

- As defined below, roles are benchmarked against peer groups appropriately representing the underlying required skill sets. These are categorized as three unique employee segments for benchmarking purposes

Segment	Rationale	Segment Definition
1) Executive (excluding CEO and direct reports)	• **Core Services Executives**: Limited to publicly-traded companies of a similar size and scope to Hydro One based on revenue and assets. Broader sample provides a sample of large Canadian companies for executive roles that are not industry-specific • **Operations Executives:** Limited to energy and utility peers, consistent with the broader operations peer group	• Vice President and above roles that are required to set the strategy and direction of Hydro One through leadership of functions that are critical to the long-term success of the organizations
2) Operations	• Reflects organizations where comparable specialized skill sets reside • Balance of public- and private-sector ownership models • Geographic representation from across Canada, but with minority Alberta representation	• Requires specific education, skills and knowledge in a professional area that is directly related to concepts and methods associated with the transmission, distribution and regulation of power. Examples include: Operations, Engineering, Skilled Trades
3) Core Services	• Incorporates a variety of private and public sector organizations based on labour market • No one industry comprises more than 20% of the total sample • Includes large number of Canadian headquartered organizations (53% of sample) to ensure benchmarking coverage of roles that require specific expertise	• Roles that require education, skills and knowledge that are not specific to the transmission, distribution and regulation of power. Examples of such functions include Finance, Human Resources and Information Technology

Peer Group Selection Criteria

- Peer groups by segment were derived from the full list of organizations participating in the 2025 WTW compensation databases, based on the criteria below. The peer groups are also used to benchmark compensation for internal oversight of Hydro One's compensation programs
- Refer to **Appendix I** for detailed peer group listings

Segment	Industry	Region	Size (Revenue)	Ownership
1) Executives *Levels 8 – 10*	• Operations: Energy Services & Utilities • Core Services: Large Canadian companies	• Canada	• Operations: >$500M • Core Services: >$2B and <$20B	• Operations: All structures • Core Services: Publicly-traded
2) Operations *Levels 4 – 7*	• Energy Services & Utilities	• Canada	• >$500M	• All structures
3) Core Services *Levels 1 – 7*	• General Industry *(excluding subsidiary Retail and Consumer Products, primary emphasis on non-subsidiaries)*	• Ontario-based employees	• Private sector >$500M • Public sector: >$100M • Subsidiaries: >$1B	• All structures

Compensation Elements and Market Statistics

- Consistent with Hydro One's compensation philosophy to target compensation at the 50th percentile, market statistics reported reflect the market 50th percentile of the benchmark samples for the data elements summarized below:
  - 50th percentile represents the level where 50% of the data points are positioned below, and above this level
- A market range is used when defining compensation competitiveness. This approach is consistent with typical methodologies for compensation benchmarking purposes
  - Given the limitations inherent in market data sources and the wide range of factors influencing individual compensation levels (e.g., nature of role, role criticality, expertise, scarcity of skillset/experience, value of role to the organization now and in the future, tenure and performance etc.), it is important to keep in mind that market data reflect an approximation of the overall market for a job
  - A specific market range may vary depending on the circumstances, including the underlying variability in the market data
    - Based on WTW's analysis of the market data and consulting experience with other utility organizations, WTW considers Hydro One's compensation to be aligned with the competitive market when it falls within a range of +/- 10% of the target market position

Compensation Element	Hydro One	WTW Competitive Market Data
Salary Range Midpoint	2026 salary range midpoint of incumbents in benchmark roles	2026 actual reported comparator organization salaries of incumbents in benchmark roles
Target Total Cash Compensation (TTC)	2026 salary range midpoints of incumbents in benchmark roles + target bonus	2026 actual reported comparator organization salary + target bonus of incumbents in benchmark roles
Target Total Direct Compensation (TTDC)	2026 salary range midpoints of incumbents in benchmark roles + target bonus + target long-term incentives (if applicable)	2026 actual reported comparator organization salary + target bonus + long-term incentives (if applicable) of incumbents in benchmark roles

Compensation Benchmark Results

- The benchmark results are provided both on a total sample and on a segmented basis. Results are summarized by the following Hydro One levels:

Hydro One Level	Hydro One Level Descriptor
10 (Executive)	Senior Vice President
9 (Executive)	Vice President
8 (Executive)	Vice President
7	Director
6	Director
5	Manager
4	Manager/Professional
3	Executive Assistant
2	Assistant
1	Assistant

- Hydro One has implemented a segmented approach to competitive benchmarking and salary structures, supported by market differences in competitive compensation. Hydro One maintains three segmented salary structures:
  - **Operations structure**: Applies to roles in the operations segment (levels 4-9)
  - **Core services structure**: Applies to roles in the core services segment (levels 1-10) and to executive roles in the operations segment (level 10)
    - **Premium core services structure**: Applies to specific roles in IT, tax and legal job functions (levels 4-7)
- The percentage above/below the market reflects the difference between the sum of Hydro One's target compensation and the sum of market results (i.e., 50th percentile), for all incumbents in benchmark roles within the respective level and segment of the compensation element illustrated

Overview: Overall Compensation Analysis Results

Overview: Overall Compensation Analysis Results

- Overall, by weighted average, Hydro One's Target Total Direct Compensation (TTDC) is positioned at the market 50th percentile
- Results by segment and compensation element are outlined below
  - Executives are positioned, on average, 5% below market P50 (within the 10% competitive market range around P50)
  - Operations roles are positioned, on average, 5% below market P50 (within the 10% competitive market range around P50)
  - Core Services roles are positioned, on average, 3% above market P50 (within the 10% competitive market range around P50)

Segment	Number of Incumbents Benchmarked	Hydro One Target Compensation Positioning vs 50th Percentile		
		Salary Range Midpoint vs Market P50	Target Total Cash (TTC) vs Market P50	Target Total Direct Compensation (TTDC) vs Market P50
Executive	26	-9%	-8%	-5%
Operations[1]	296	-2%	-2%	-5%
Core Services[1,2]	456	0%	2%	3%
Overall[3]	778	-1%	0%	0%

1. Operations and Core Services positioning excludes levels 8-10
2. Reflects Core Services and Core Services Premium segments
3. Represents incumbent weighted results across all segments

Compensation Analysis Results

Segments: All Segments

- On an overall basis, Hydro One is positioned, on average, at the market 50th percentile on a Target Total Direct Compensation (TTDC) basis

Level	Employees	Segment	Salary *(Structure Midpoint vs. Market P50)*	Target Total Cash *(Structure Midpoint vs. Market P50)*	Target Total Direct Compensation *(Structure Midpoint vs. Market P50)*
SVP - 10	2	All Segments	-13%	-12%	7%
VP - 9	13	All Segments	0%	2%	9%
VP - 8	19	All Segments	-14%	-13%	-11%
Director - 7	52	All Segments	-7%	-8%	-2%
Director - 6	48	All Segments	-3%	-2%	2%
Manager - 5	299	All Segments	1%	1%	-1%
Mgr./Professional - 4	338	All Segments	-1%	1%	0%
Exec Assist. - 3	65	All Segments	0%	0%	0%
Assistant - 2	50	All Segments	2%	5%	4%
Assistant - 1	0	All Segments	--	--	--
	Incumbent Weighted Averages		**-1%**	**0%**	**0%**

Compensation Analysis Results

Operations

- Overall, operations roles are positioned 5% below the market 50th percentile (within the 10% competitive market range around P50) on a Target Total Direct Compensation (TTDC) basis

Level	Count	Operations Segment	**Salary** ($000s)	**Target Total Cash** ($000s)	**Target Total Direct Compensation** ($000s)
			Salary Range Midpoint vs. Market P50	TTC Range Midpoint vs. Market P50	TTDC Range Midpoint vs. Market P50
Director - 7	26	Operations	-8%	-11%	-10%
Director - 6	22	Operations	-4%	-6%	-9%
Manager - 5	151	Operations	1%	0%	-5%
Mgr./Professional - 4	159	Operations	-4%	-2%	-4%
		Incumbent Weighted Averages	-2%	-2%	-5%

Compensation Analysis Results

Core Services

- Overall, Core Services roles are positioned 3% above the market 50th percentile (within the 10% competitive market range around P50) on a Target Total Direct Compensation (TTDC) basis

Level	Count	Core Services Segment	**Salary** ($000s)	**Target Total Cash** ($000s)	**Target Total Direct Compensation** ($000s)
			Salary Range Midpoint vs. Market P50	TTC Range Midpoint vs. Market P50	TTDC Range Midpoint vs. Market P50
Director - 7	23	Core Services	-5%	-5%	7%
Director - 6	22	Core Services	-2%	1%	11%
Manager - 5	132	Core Services	0%	2%	1%
Mgr./Professional - 4	149	Core Services	2%	3%	3%
Exec Assist. - 3	65	Core Services	-1%	-1%	-1%
Assistant - 2	50	Core Services	1%	5%	4%
Assistant - 1	0	Core Services	--	--	--
		Incumbent Weighted Averages	0%	2%	3%

Compensation Analysis Results

Premium - Core Services

- Overall, Premium - Core Services roles are positioned 7% above the market 50th percentile (within the 10% competitive market range around P50) on a Target Total Direct Compensation (TTDC) basis

Level	Count	Core Services Segment	**Salary** ($000s)	**Target Total Cash** ($000s)	**Target Total Direct Compensation** ($000s)
			Salary Range Midpoint vs. Market P50	TTC Range Midpoint vs. Market P50	TTDC Range Midpoint vs. Market P50
Director - 7	3	Core Services Premium	-13%	-12%	1%
Director - 6	4	Core Services Premium	4%	7%	18%
Manager - 5	16	Core Services Premium	3%	6%	5%
Mgr./Professional - 4	30	Core Services Premium	4%	7%	7%
		Incumbent Weighted Averages	3%	6%	7%

Appendix

Peer Group: Executive Operations

Executive Operations Peer Group (n= 46)			
Alberta Electric System Operator	ConocoPhillips	Imperial Oil	Pembina Pipeline
Algonquin Power & Utilities	Emera	Innergex Renewable Energy	Santee Cooper
AltaGas	Enbridge	Irving Oil	Shell
ARC Resources	Énergir	MEG Energy	South Bow
Boralex	EPCOR Utilities	Nexus Water Group	Strathcona Resources
British Columbia Hydro and Power Authority	Fortis	NOV	Suncor Energy
Bruce Power	FortisAlberta	NOVA Chemicals	TC Energy
Canadian Natural Resources	FortisBC	Nutrien	Trans Mountain
Canadian Nuclear Laboratories	GE Vernova	Obsidian Energy Ltd.	Valero Energy
Capital Power	Gibson Energy	Ontario Power Generation	Wood
Cenovus Energy	Halliburton	Ovintiv	
CNOOC Petroleum	Hydro-Québec	Parkland Corporation	

Percentile Statistics	Revenue	Assets
25th Percentile	$2,104,095,000	$13,057,275,000
50th Percentile	$4,999,940,000	$22,628,700,000
75th Percentile	$13,621,415,000	$71,921,500,000
Hydro One	**$8,484,000,000**	**$36,682,000,000**
Percent Rank	65P	63P

Ownership Structure	% of Total
Public Parent	48%
Wholly Owned Subsidiary	22%
Government Agency	17%
Private Parent	11%
Publicly Traded Subsidiary	2%

Peer Group: Executive Core Services

Executive Core Services Peer Group (n= 88)			
ADM - Archer Daniels Midland	Cencora	Gibson Energy	Publicis
Albertsons	CGI - Conseillers en Gestion et Informatique	Gildan Activewear	Reinsurance Group of America (RGA)
Alcoa	Church & Dwight	Holcim	Restaurant Brands International
Algonquin Power & Utilities	Cintas	IA Financial Group	Rexel
AltaGas	CNOOC Petroleum	Interfor	Rio Tinto
American Express	Cogeco	Johnson & Johnson	RXO Inc.
ARC Resources	Colliers International	Kinross Gold	Snap-on
Argenx	Computershare Loan Services	Konecranes	South Bow
Aviva	ConocoPhillips	Lululemon Athletica	Stantec
Barrick Gold	Definity Insurance Company	Maple Leaf Foods	Strathcona Resources
Bausch Health Companies	Dollarama	McKesson	TC Energy
Boeing	DXC Technology	MEG Energy	Teck Resources
Bombardier	Electronic Arts	Meta	Thomson Reuters
BRP - Bombardier Recreational Products	Element Fleet Management	Microsoft	TJX Companies
CAE	Emera	Munich Re Group	Transamerica
Canadian National Railway	Empire Life	Northbridge Financial Corp	Ubisoft
Canadian Pacific Kansas City	Finning International	Okta	Valero Energy
Canadian Tire Corporation	Fluor	Ovintiv	Veralto
Canfor Corporation	Ford	Palo Alto Networks	Vidéotron Ltée
Capital Power	Fortis	Pembina Pipeline	Vontier
Cascades	FortisBC	PepsiCo	Wesco International
Celestica	GFL Environmental	Post Holdings	WSP

Percentile Statistics	Revenue	Assets
25th Percentile	$3,640,645,000	$8,125,270,000
50th Percentile	$5,933,675,000	$14,096,655,000
75th Percentile	$11,610,595,000	$27,418,685,000
Hydro One	**$8,484,000,000**	**$36,682,000,000**
Percent Rank	65P	84P

Ownership Structure	% of Total
Public Parent	64%
Wholly Owned Subsidiary	36%
Government Agency	0%
Private Parent	0%
Publicly Traded Subsidiary	0%

Peer Group: Operations

Operations Peer Group (n= 52)			
Alberta Electric System Operator	ConocoPhillips	Hydro-Québec	Ovintiv
Algonquin Power & Utilities	Dow Chemical	Imperial Oil	Parkland Corporation
AltaGas	Emera	Innergex Renewable Energy	Pembina Pipeline
ARC Resources	Enbridge	Irving Oil	Precision Drilling
Boralex	Énergir	LNG Canada	Santee Cooper
British Columbia Hydro and Power Authority	EPCOR Utilities	MEG Energy	Shell
Bruce Power	ExxonMobil	Nexus Water Group	South Bow
Canadian Natural Resources	FortisAlberta	NOV	Strathcona Resources
Canadian Nuclear Laboratories	Fugro	NOVA Chemicals	Suncor Energy
Capital Power	GE Vernova	Nova Scotia Power	TC Energy
Cenovus Energy	Gibson Energy	Nutrien	Trans Mountain
CF Industries	Halliburton	Obsidian Energy Ltd.	Valero Energy
CNOOC Petroleum	HF Sinclair	Ontario Power Generation	Wood

Percentile Statistics	Revenue	Assets
25th Percentile	$1,471,950,000	$10,977,500,000
50th Percentile	$4,163,000,000	$17,764,035,000
75th Percentile	$13,322,245,000	$56,539,000,000
Hydro One	**$8,484,000,000**	**$36,682,000,000**
Percent Rank	69P	68P

Peer Group: Core Services (1/2)

Core Services Peer Group (n= 334)				
123Dentist	Barrick Gold	Canpotex	Dow Jones	Gibson Energy
3M	BASF	Capital One Financial	Dura-Line	Gildan Activewear
AbbVie	Bausch Health Companies	Capital Power	DXC Technology	Gordon Food Service
Accenture	Bayer	CareRX	EBSCO Information Services	Great Canadian Gaming Corporation
ADM - Archer Daniels Midland	Bechtel	Cargill	Electronic Arts	Greystar
Agropur Cooperative	Bell Canada	Cascades	Element Fleet Management	GROWMARK
AIG	Beneva	CDW	Eli Lilly	Hach
Air Canada	BioCryst Pharmaceuticals	Celestica	Emera	Hard Rock Digital
Alberta Electric System Operator	Black & McDonald	Cencora	Empire Life	HD Supply
Alberta Health Services	Block	Cenovus Energy	Enbridge	Heidelberg Materials
Alberta Investment Management	BMO Financial Group	CF Industries	Entain	HF Sinclair
Albertsons	Boeing	CGI - Conseillers en Gestion et Informatique	EPCOR Utilities	HMH Education Company
Alcoa	Bombardier	Chubb	Ernst & Young	Holcim
Algonquin Power & Utilities	Boralex	Church & Dwight	Estée Lauder	Holt Renfrew
Aliaxis	British Columbia Hydro and Power Authority	CIBC Mellon Global Securities Services	EXA Infrastructure	Home Depot
Ally Financial	British Columbia Investment Management	Cisco Systems	Export Development Canada	HP Inc.
AltaGas	Brookfield Asset Management	Citigroup (Global)	ExxonMobil	HSBC Bank
Amazon.com	BRP - Bombardier Recreational Products	City of Calgary	ExxonMobil Business Support Centre	HSS Enterprises
American Express	Bruce Power	CNH Industrial	Factors Group	Hydro-Québec
Apexon	Bunge	CNOOC Petroleum	Farm Credit Canada	IA Financial Group
Apotex	Business Development Bank of Canada	Cofra Holding	Federated Co-Operatives Limited	Imperial Oil
Apple	CAE	Colliers International	FGF Brands	Innergex Renewable Energy
ARC Resources	Caisse de dépôt et placement du Québec	Computershare Loan Services	FGL Sports	Intact Financial Corp.
Argenx	Calgary Co-operative Association	Connor, Clark & Lunn Financial Group	Finning International	Intercontinental Hotels Group
AstraZeneca	Canada Life	ConocoPhillips	Fluor	Interfor
Athene	Canada Mortgage and Housing	CPP Investment Board	FM	Intuit
Autoliv	Canadian Imperial Bank of Commerce	Danaher	Ford	IPG Mediabrands
Automatic Data Processing	Canadian National Railway	Deere & Company	Ford Financial	Irving Oil
Aviva	Canadian Natural Resources	Definity Insurance Company	Foresters Financial	Ivari
AXA XL	Canadian Nuclear Laboratories	Deloitte	Four Seasons Hotels and Resorts	Jamieson Wellness
Badger Daylighting	Canadian Pacific Kansas City	dentalcorp	Gap	JOEY Restaurant Group
Bain & Company	Canadian Tire Corporation	DIRECTV	Gateway Casinos & Entertainment	John Wiley & Sons
Balcan Innovations Inc	Canadian Tire Financial Services	Dollarama	General Dynamics Land Systems	Johnson & Johnson
Bank of America (Global)	Canfor Corporation	Domtar	GFL Environmental	JP Morgan Chase (Global)

Peer Group: Core Services (2/2)

Core Services Peer Group (n= 334)				
KalTire	Moderna	Pfizer	Seedtag Advertising	Toromont Industries
Keurig Dr Pepper	Molson Coors Beverage Company	Post Holdings	Serco Inc.	Transamerica
Kinross Gold	Moneris Solutions	Precision Drilling	SGI Canada	Transat A.T.
L3Harris	Moog	Premier Tech	Shell	Travelers
Lantic Inc.	Morgan Stanley (Global)	Previan	Siemens	Travelport
Laurentian Bank of Canada	Mouvement Desjardins	PSP Investments	Signant Health	UAP
Ledcor Industries	Munich Re Group	PTC Therapeutics	Sirius XM Radio	UFA - United Farmers of Alberta
Linde	Nasdaq	Publicis	SMS Equipment	Under Armour
Liquor Control Board of Ontario	National Bank of Canada	Radial	Smurfit Westrock	United Rentals
Loblaw Companies	NAV Canada	RBC Financial Group	Sobeys	University of Saskatchewan
London Drugs	NCR Voyix	Reinsurance Group of America (RGA)	Sony Interactive Entertainment	UPM
L'Oréal	Netflix	Republic Services	Stantec	Valero Energy
Loto-Québec	Newmont Mining	Restaurant Brands International	Starbucks	Vancity
Lululemon Athletica	Nexus Water Group	Revlon	State Street	Veralto
Lumen	Northbridge Financial Corp	Rexall Pharmacy Group	Strathcona Resources	Videojet Technologies
Magna International	NOVA Chemicals	Rio Tinto	Sun Life Financial	Vidéotron Ltée
Maker's Pride	Nova Scotia Power	Roche Pharmaceuticals	Suncor Energy	Vontier
Manulife	Novartis	Rona	Sunwing Travel Group	Walmart
Maple Leaf Foods	Novo Nordisk	Roots Canada	Survitec Group	Warner Bros. Discovery
Mark Anthony Group	Nutrien	Royal Bank of Canada	Sysco Corporation	Waste Management
Mark's Work Wearhouse	Obsidian Energy Ltd.	RTX	Taylor & Francis	Wesco International
Mars Incorporated	Okta	RXO Inc.	TC Energy	West Fraser Timber
Marsh McLennan	OMERS	Saint-Gobain	TD Bank Financial Group	Westlake Chemical
McCain Foods	Ontario Power Generation	Salesforce	Teck Resources	WildBrain
McCann Worldgroup	Ontario Teachers' Pension Plan Board	Samuel, Son & Co. Limited	Telus	Wolters Kluwer
McDonald's	Openlane	Sandoz	The Co-operators Group Limited	Workplace Safety and Insurance Board
McKesson	Ovintiv	Santee Cooper	The Master Group	Worksafe BC
MDF Commerce	Owens & Minor	SAP	The Wawanesa Mutual Insurance	Worldline
MEG Energy	Palo Alto Networks	Savage Services	Thermo Fisher Scientific	WSP
Meta	Partners Group	Scopely	Thomson Reuters	Yazaki Corporation
Michelin North America	PayPal	Scotiabank	ThoughtWorks	Zekelman Industries
Microsoft	Pembina Pipeline	Seaspan Ship Management	TJX Companies	Zscaler
MLSE - Maple Leaf Sports & Entertainment	PepsiCo	Seaspan Shipyards	TMX Group	

Percentile Statistics	Revenue	Assets
25th Percentile	$1,484,135,000	$7,693,300,000
50th Percentile	$3,671,310,000	$26,536,745,000
75th Percentile	$12,045,195,000	$87,744,000,000
Hydro One	**$8,484,000,000**	**$36,682,000,000**
Percent Rank	69P	57P

WORKFORCE STRATEGY

1.0 INTRODUCTION AND OVERVIEW

This Exhibit describes the workforce required to build, operate, and support Hydro One's Transmission and Distribution systems. Detailed below are the categories of Hydro One employees and the company's robust and collaborative workforce planning process. That process was used to forecast the required resources to execute the investment plan over the 2028-2032 planning period, including for operational flexibility during the execution of planned and demand-driven work volumes. The forecasted Full-Time Equivalent employees (FTEs)[1] required to execute the plan are provided.

Hydro One forecasts an increase in FTEs to execute its growing investment plan over the 2028-2032 planning period. FTEs initially increase by approximately 11% from 2027 to 2028 to support a corresponding 36% step-change in the investment plan.[2] The majority of this increase consists of casual employees which enhances resourcing flexibility. From 2029-2032, FTEs increase by approximately 3% overall, in support of the investment plan which continues to grow by 5% annually. Investment plan growth is comprised of both increased expenditures and increased work volumes compared to the current period. Hydro One's resources forecast demonstrates an overall trend of improvement in the ratio of FTEs to investment plan spend from 2023 to 2032.

Hydro One's forecasted resources reflect the terms of its collective agreements with key union partners in the Power Workers' Union (PWU) and Society of United Professionals (SUP), which together represent 75% of the company's workforce. The workforce plan also reflects Hydro One driven efficiencies, including: collective bargaining outcomes which create flexibility to efficiently contract certain work; availability of casual and

[1] At Hydro One, FTEs represent average monthly headcount over a 12-month period. A regular status employee who is budgeted for one year of work, represents one FTE. For casual employees, one FTE equates to 12 person months of work. For example, if one casual employee worked for six months they would account for 0.5 FTEs.
2 Investment Plan includes capital expenditures, prepaid cloud costs and OM&A, excluding property taxes.

temporary employees to manage peak and short term work volumes; retention of an experienced and talented regular workforce to maintain ongoing operational excellence; and refinement to the workforce planning process which increased collaboration, validation points and alignment with business planning.

Table 1 below provides a breakdown of witness accountability for Workforce Strategy. Workforce compensation is addressed in Exhibit E-06-01 Compensation, which details the compensation and benefit entitlements for each segment of the workforce.

Table 1 - Witnesses Accountability

Workforce Strategy	Witness
2.0 Hydro One's Workforce	Lyndsay Fulton
3.0 Workforce Planning Process & Anticipated FTE levels for the Rate Period	Lyndsay Fulton
3.1 Hydro One's Comprehensive Approach to Workforce Planning	Lyndsay Fulton
3.2 Actual and Planned FTEs	Lyndsay Fulton Gianni DiFilippo (Distribution) Scott Vicary (Transmission)

2.0 HYDRO ONE'S WORKFORCE

This section describes the segments of employees that comprise Hydro One's workforce. Overall compensation costs are impacted by the workforce mix, which is the aggregate of the number, level and type of FTEs. Workforce mix is therefore an essential component of ensuring cost-effective and efficient work delivery to the benefit of customers.

Below and in Figure 1 are the three segments of employees which make up Hydro One's workforce and the percentage each comprises.

1. Regular Employees: 75%
    a. Represented – PWU, SUP
    b. Management and Non-Represented (MGT-NR)
2. Casual: 23%

a. Represented – PWU (Hiring Hall, including Apprenticeship Program)[3]
b. Represented – Members of a building trades union (BTU), such as the Canadian Union of Skilled Workers (CUSW)[4], International Brotherhood of Teamsters (Teamsters), Carpenters Regional Council, United Brotherhood of Carpenters and Joiners of America (Carpenters), Labourers International Union of North America (LIUNA), International Union of Operating Engineers (Operating Engineers), or International Association of Bridge, Structural, Ornamental and Reinforcing Ironworkers (Ironworkers), which each negotiate province wide collective agreements through the employer's association the Electrical Power System Construction Association (EPSCA)

3. Temporary: 2%
   a. Represented – PWU, SUP
   b. MGT-NR

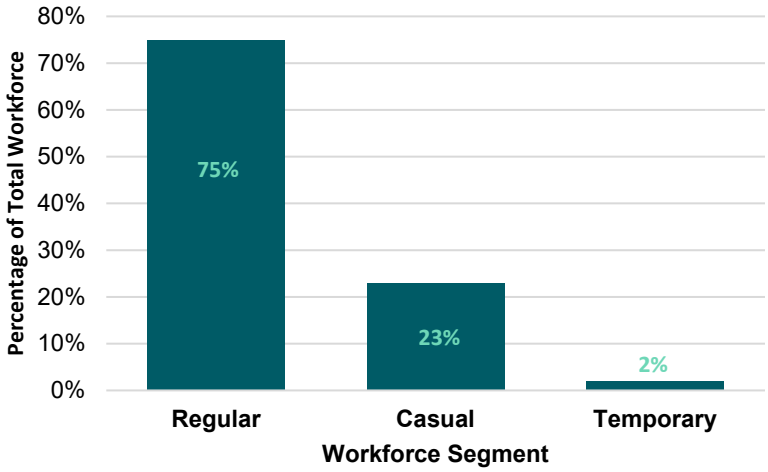

Figure 1: Total Workforce Segments 2025

[3] The PWU Hiring Hall (PWU HH) is a partnership between the PWU and Hydro One that trains and employs apprentices and qualified journeypersons who are available for intermittent work by providing a skilled, mobile and flexible workforce.
[4] CUSW is a building trades union; however, Hydro One negotiates directly with CUSW, rather than through the Electrical Power Systems Construction Association

Approximately 91% of Hydro One's workforce (regular, casual and temporary) is represented by a union and is subject to the terms of a collective agreement. Figure 2 below shows the proportion of representation by each union group Hydro One employs.

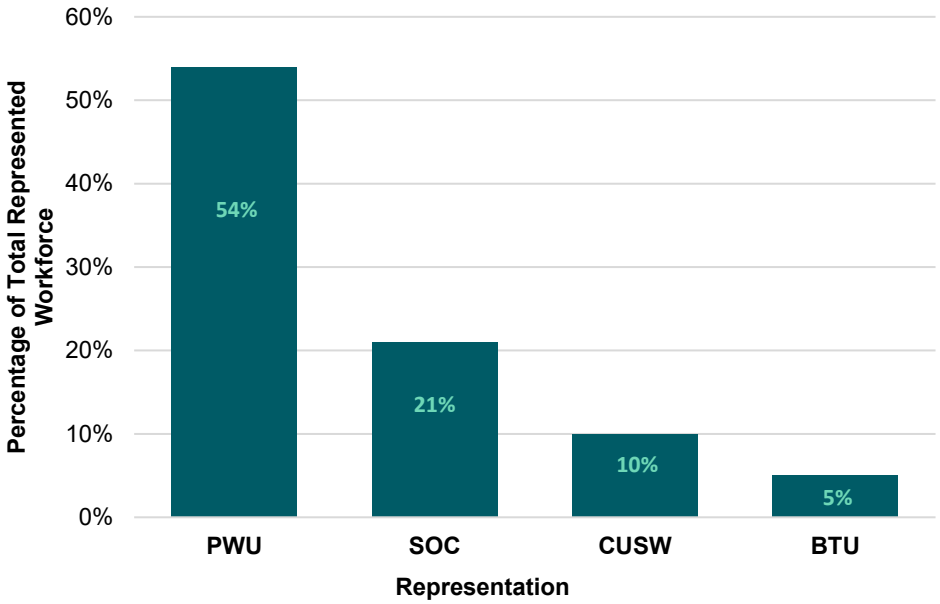

Figure 2: Total Workforce Representation[5] Groups 2025

In addition to its internal workforce, Hydro One also uses external resources to support work execution by contracting certain short-term or specialty work to vendor partners or individuals.

2.1 REGULAR EMPLOYEES

2.1.1 REPRESENTED GROUPS

Approximately 88% of regular employees (and 91% of all employees) are represented by unions. About 60% of regular employees (and 54% of all employees) are represented by

[5] PWU refers to the Power Workers' Union; SUP is the Society of United Professionals; CUSW is the Canadian Union of Skilled Workers; BTU refers to those employees represented by building trades unions that negotiate with the Electrical Power Systems Construction Association.

the PWU. Approximately 28% of regular employees (and 21% of all employees) are represented by the SUP.

In respect of both PWU and SUP represented employees, Hydro One competes to attract, retain, develop and motivate these highly skilled workers to execute Hydro One's growing work program. These employees are sought after by other employers, including the Ontario Hydro successor organizations and other utilities due to their highly specialized skill sets. Employees represented by the PWU occupy roles related to technical, trades, clerical, or customer service and call centre functions under the PWU collective agreement, and perform work such as lines, forestry, electrical, mechanical, protection and control, meter reading, stock keeping, and system operations, as well as clerical/administrative work. A significant portion of this workforce is trained internally through the apprenticeship program described below in section 2.2.2 and other trainee programs.

Approximately 48% of regular, full-time PWU-represented employees (21% of the entire Hydro One workforce) work as Regional Maintainers (RMs). RMs are qualified members of a skilled trade in the areas of lines, electrical, forestry, civil, or mechanical work. In addition to being proficient in their trade, RMs are also expected to be capable in lead hand duties, contract monitoring, and protection and control. On average, it takes between four to five years to become qualified in a skilled trade specific to the utility sector through a combination of an apprenticeship or trainee program and on-the job training.

Employees represented by the SUP occupy roles related to technical, engineering, supervisory or financial and analytical work. An example of a supervisory role is the Front-Line Managers who oversee the work of PWU staff in Lines, Forestry, and other technical services. SUP-represented staff also play key roles in the oversight, analysis, and business planning of network operations, as well as protection and control work and project management.

2.1.2 MANAGEMENT AND NON-REPRESENTED (MGT-NR) EMPLOYEES

The remaining 12% of the regular workforce (9% of the total workforce) is not represented by a union. These are primarily employees in managerial roles, as well as those positions that are excluded from union representation for reasons such as confidentiality relating to labour relations or legal matters. The MGT-NR workforce leads the company by setting strategy and providing work direction. Hydro One seeks to hire a mix of internal and external talent for these roles.

2.2 CASUAL EMPLOYEES

Casual employees are typically retained for 35-40 hours a week for a fixed period, primarily to execute and support construction work, supplemental maintenance work, supplemental customer service and clerical support work.

Unlike regular employees, casual employees are contingent workers hired to perform specific work for a set period and then can be laid off. The flexible terms of casual labour ensure that workers with the required skill set are hired in the right location for only the duration of the work assignment required.

As presented in Figure 3 below, casual workers are either:

- Represented by the PWU and employed through a hiring hall (PWU HH) as discussed further under Section 2.2.1 below;
- Represented by the CUSW and perform skilled trades work in transmission system construction as discussed further under Section 2.2.3 below; or
- Members of a building trades unions, as discussed further under Section 2.2.4 below.

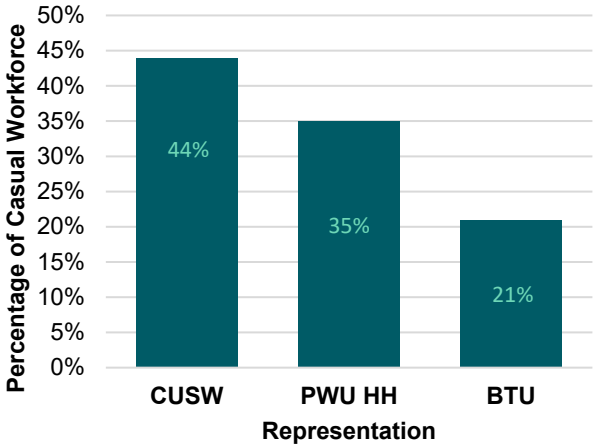

Figure 3: Representation of Casual Workforce 2025

2.2.1 PWU HIRING HALL (PWU HH)

The PWU administers a hiring hall of contingent workers to meet fluctuating work demands (e.g., incremental work, the Apprenticeship Program, and special projects), performing primarily supplemental construction, maintenance, customer service, clerical support or technical work. The PWU HH makes up 35% of all casual employees. When work volumes fluctuate and workers are required, Hydro One will requisition this labour through a union-run hiring hall directly. The union is responsible for ensuring that the labour demands can be met and the staff within their hall are qualified and ready for work.

2.2.2 PWU APPRENTICESHIP PROGRAM

Apprentices are employed as casual workers for the duration of their apprenticeship program and, in many cases, beyond program completion. There is no guarantee of ongoing work for an apprentice while they acquire the training and experience required in various skilled trades and technical apprenticeship programs, such as utility arborist, powerline technician, truck and coach technician, electrician or cable splicer trades.

Once an apprentice has completed their program, which takes approximately four to five years, they can apply to available regular positions. Given that work program demands fluctuate, this model provides flexibility to hire qualified tradespersons based on confirmed

operational need, eliminating the requirement to hire several years in advance of potential work. If apprentices are not hired into a regular position, they can remain in the PWU HH and be available for referral if work becomes available. In addition, apprentices in the lines trade are deployed to support both Transmission and Distribution work, making them a flexible and adaptable resource to meet work demands, and support a variety of work programs.

2.2.3 CANADIAN UNION OF SKILLED WORKERS (CUSW)

Hydro One relies on casual CUSW-represented employees from the buildings trades to perform construction industry work on the electrical power systems. This group makes up 44% of all casual employees at Hydro One. These employees are a flexible resource which brings skills that can support a variety of work programs, and which can efficiently meet fluctuating work demands.

2.2.4 BUILDING TRADES UNION EMPLOYEES

Building trades employees are casual status employees that are represented by construction (or building trades) unions that supply a contingent workforce through their hiring halls. Building trades employees make up 21% of all casual employees at Hydro One. They provide Hydro One with similar resource flexibility as other union groups representing casual employees, and bring a variety of skills to meet varied duties and fluctuating work demands.

2.3 TEMPORARY EMPLOYEES

Temporary employees exist in the PWU, SUP and MGT-NR classifications. These employees are typically retained for 12 to 18 months, or up to two years for some non-represented positions. They are hired to fill positions where the duration or volume of the work does not warrant the hiring and retention of a regular employee. They are most often hired for work on a fixed term basis, for example, to cover a leave of absence, or complete short-term project work. They are not typically hired for work that is of an ongoing nature.

Temporary employees are distinct from casual employees. All casual employees are governed by the applicable collective agreements and perform work within negotiated bargaining unit classifications. Temporary employees cannot perform work that falls within these bargaining unit classifications.[6] Temporary roles are therefore not interchangeable with, and do not substitute for, casual positions.

2.4 EXTERNAL RESOURCES

In addition to its internal workforce, Hydro One utilizes external resources to support the execution of its work programs. The extent to which work may be performed by external resources depends on several factors, including the nature of the work and applicable work jurisdiction under the relevant collective agreements. In particular, the work jurisdiction of the PWU influences the scale and type of work that may be contracted. By contrast, under the SUP and CUSW collective agreements, Hydro One has greater flexibility to utilize external resources, as those agreements do not contain comparable restrictions on contracting. In a highly unionized operating environment, work jurisdiction is a key consideration and is assessed alongside operational requirements when determining the appropriate sourcing approach.

Hydro One's use of external resources is intended to balance workforce flexibility, cost efficiency, and operational reliability. The planned and ongoing work program is resourced primarily through regular and casual FTEs, with workforce levels established through a planning process based on the specific work program activities included in the investment plan (this process is detailed below in section 3.0). External resources are used selectively to address variability in workload, changes in the timing or location of work, and the execution of large capital projects or activities requiring specialized skills or equipment that are not efficient or practical to maintain internally. Expanding the internal workforce to meet this incremental demand would not be cost effective, as associated overhead costs, such as additional vehicles or specialized equipment, would persist beyond the period of need.

[6] The one exception to this distinguishing characteristic is that both casual and temporary employees are both eligible to fill clerical roles.

Decisions regarding the use of external resources are therefore informed by the workforce planning process and the nature of the work required to deliver the investment plan. Planned work is translated into labour requirements and appropriate resourcing approaches, including the use of regular, casual, or contracted resources, taking into consideration factors such as work jurisdiction, capacity, timing, and skill requirements. The decision to utilize external resources is reviewed as part of Hydro One's investment and workforce planning processes to ensure continued alignment with program requirements, collective agreements, and regulatory expectations.

2.4.1 CONTRACTING

Hydro One will continue its strategic use of contractors to supplement its internal workforce, scaling contracted resources as required to address forecasted increases in work demand in 2028 and beyond. This enables Hydro One to efficiently manage periods of higher or variable workload. This approach mitigates the need to increase FTEs for short-term needs and therefore mitigates the associated long-term pension and benefit obligations to address temporary, incremental, seasonal, or short-term work demand. Appropriate and strategic use of contracting supports workforce flexibility and cost effectiveness.

Some types of work that Hydro One seeks to contract may require negotiation with the union partners or an award from a Labour Arbitrator. Factors such as labour availability within existing casual hiring halls may be relevant to the determination of the types and volumes of work that can be contracted. Through negotiation, Hydro One has achieved workforce flexibility that enables the organization to supplement the regular workforce with the casual workforce and use external resources in various advantageous circumstances.

The PWU collective agreement contains provisions that address contracting, referred to as Purchased Services Agreements (PSAs). Certain categories of work have been subject to long-standing PSA arrangements that have been integrated into the PWU collective agreement. For example, the agreement known as Mid-Term 50 permits the contracting of entire categories of work, rather than requiring individually negotiated agreements, including snow removal, janitorial, heavy and/or specialized equipment operation (e.g.

hydro-vac, backhoe), and minor fleet maintenance. Hydro One may contract this work to organizations that specialize in these areas. These arrangements provide flexibility by enabling on-demand resources to be deployed as required through various contracting partners and allow Hydro One to avoid the costs of equipment, maintenance, labour, and training for services that are needed on an intermittent basis or are highly specialized.

Additionally, since 2011, Hydro One has maintained significant workforce flexibility under the SUP collective agreement. The agreement permits Hydro One to retain external resources to perform work within the jurisdiction of the bargaining unit, provided that no employee loses employment as a direct result of the contracting arrangement.

Contracting is also recognized in the CUSW collective agreement, which includes provisions that stipulate those employees represented by the International Brotherhood of Electrical Workers (IBEW) can perform electrical construction work through affiliated contractors. In Ontario, there are two electrical unions which represent electrical construction workers in this sector - the IBEW and the CUSW. The CUSW collective agreement allows for work to be contracted out to either (a) CUSW-affiliated contractors, (b) IBEW-affiliated contractors, or (c) other contractors agreeing to apply the terms and conditions of the CUSW agreement.

In most cases with construction contracting, the contractors need to be affiliated with the same unions who would perform the work if it had been completed by Hydro One. However, this is not the case with CUSW as additional contracting flexibility has been achieved. The flexibility is important, as Hydro One’s ability to use IBEW-affiliated and other contractors leads to a larger contractor pool and more competitive contractor bids. While contracting in the construction sector is a normal business practice and is supported by the unions, Hydro One’s arrangement with CUSW ensures the entire marketplace of electrical contractors can be leveraged.

2.4.2 INDIVIDUAL CONTRACTORS

A small portion of work at Hydro One is performed by individuals that are engaged as contractors. These individual contractors differ from the contracted firms retained to scale up operations or support incremental/specialized work (typically vendors or general contractors that supply specialized services for seasonal/incremental work, or support capital work programs, specific engineering work, or provide other specialized construction services). Hydro One retains individual contractors to perform professional services in various lines of business across the company.

These contractors are retained for their skillsets on projects, and/or to perform other work that is not typically of an ongoing nature. They are engaged for varying amounts of time. Dependent on the nature of the work being assigned, individual contractors may be represented by a union. Where applicable, the use of contract staff is governed by the terms of the collective agreements.

2.5 OPTIMIZING THE CURRENT WORKFORCE

Hydro One remains focused on retaining, developing and effectively deploying its existing workforce to support the safe, reliable and efficient delivery of its work programs. An experienced internal workforce brings established technical capability and institutional knowledge of Hydro One's assets, systems, processes, and operational requirements. Workforce optimization initiatives are intended to maximize the use of this existing capacity, which reduces the requirement for additional FTEs. Retention, targeted development and effective knowledge transfer help preserve continuity and mitigate the near-term productivity impacts associated with onboarding and developing new employees, where additional FTEs are required.

Hydro One develops workforce capability through role-based technical, safety and compliance training, internal and external learning, and individual development planning. Learning is delivered through self-directed, instructor-led and experiential formats, and is aligned, where applicable, with current role requirements and the capabilities needed to support future work programs. For people leaders, Hydro One's Leader of Tomorrow

Competency Framework establishes consistent leadership expectations and is being integrated into hiring, performance assessments, talent reviews and succession planning. Leadership assessments, coaching and development programs further support focused development, from supervisor through executive levels.

Through Hydro One's annual Talent Review and Succession Planning cycle, the company assesses leadership potential and readiness, identifies successors and focuses development on areas of greatest business and succession need. Individualized development opportunities, cross-functional rotations, stretch assignments and experiential learning are used to broaden technical, industry and enterprise experience and strengthen readiness for leadership and critical roles. Hydro One prioritizes internal development and mobility where the required capability and readiness exist. External recruitment is used selectively where specialized technical or industry capabilities cannot be developed or mobilized internally within the timeframe required to deliver planned work.

In addition to developing talent internally, the company develops longer-term capability through early-career and skilled-trades pathways. Through its Early Talent Program and partnerships with colleges, universities and other institutions, Hydro One provides campus recruitment, summer student lottery, co-op and new graduate opportunities, together with apprenticeship and mentorship initiatives. These structured pathways enable Hydro One to develop specific technical capability, support knowledge transfer from experienced employees, and build the workforce required to meet future work-program needs.

Finally, Hydro One maintains an integrated workforce that creates versatility as resources can be deployed across both the Distribution and Transmission businesses. The integrated workforce creates efficiencies that would not be available through separate Transmission and Distribution operations, including an integrated Lines Apprenticeship Program where participants learn cross-functionally to be prepared as future versatile employees.

Optimization of the workforce not only contributes to reducing the number of additional FTEs required in the resource plan but also helps to offset the impact of retirements. Through efficiencies, Hydro One can maintain operational continuity, retain critical institutional knowledge, and absorb workload impacts associated with workforce attrition.

As noted in Figure 4 below, approximately 19% of Hydro One's workforce has or is expected to retire between 2024 – 2032. Projected turnover has been accounted for in the FTE forecasts detailed in Table 2 and further discussed below under Section 2.6.

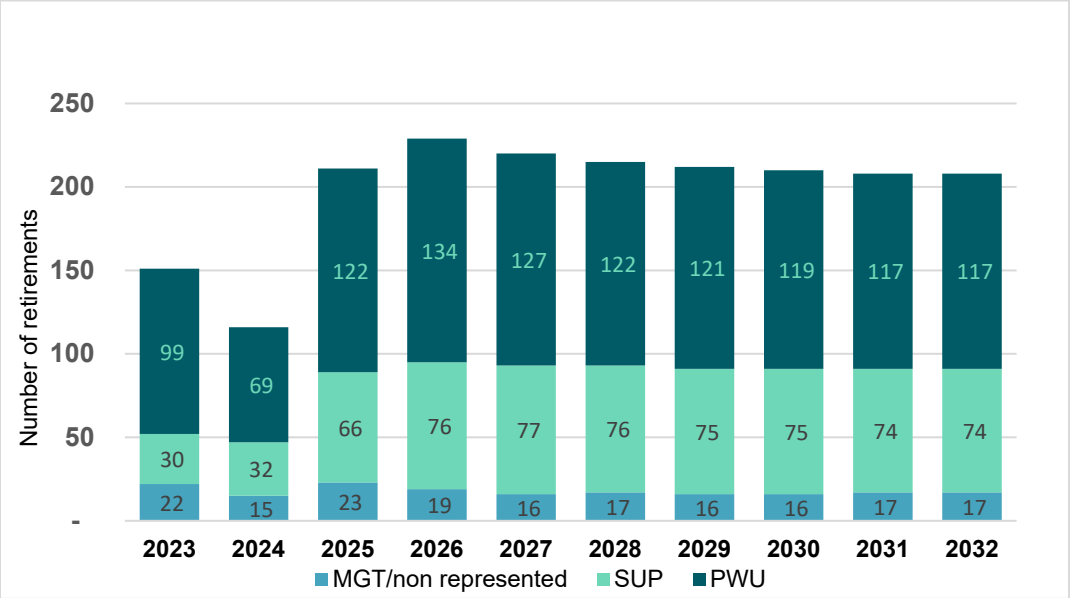

Figure 4: Hydro One Retirement Expectancy[7]

2.6 OPTIMIZING WORK DELIVERY CAPACITY WITH THE STRATEGIC USE OF OVERTIME

Hydro One also optimizes the work delivery of its employees through the strategic use of overtime (OT). OT is work that is performed in addition to, or outside of standard work

[7] For 2026–2032, the chart shows the projected number of retirements by employee group, based on the retirement rates from the December 31, 2024, funding valuation. These projections reflect expected retirements based on age, service, and each group's unreduced pension criteria. They also account for the fact that not all members retire exactly when first eligible, and that some may retire with a reduced pension.

hours. Specific terms of OT are governed by the language negotiated and contained within collective agreements. Effective use of OT is an important component of Hydro One's resourcing plan because it can be necessary to meet customer needs and work execution requirements.

The operational realities of Hydro One require two forms of OT: planned OT and demand OT. Planned OT is required to meet timelines, enhance the efficiency of work execution by, for example, minimizing mobilization and travel time, and to accommodate the needs of customers by managing outages during evenings and weekends to limit business and community disruption. Demand OT arises from work requirements that are inherently unpredictable and time sensitive. This includes responding to system events such as storm-related damage, emergency trouble calls, and customer connections that must be completed within prescribed service standards. Severe weather events are a significant driver of demand OT, as they require immediate mobilization of crews to prepare for, respond to, and restore service following damage to the system. Storm response activities often involve extended working hours, large scale deployment of various resources, and restoration efforts that continue until service reliability and public safety are fully restored. The use of demand OT in these circumstances is necessary to maintain system reliability, support timely restoration, and minimize the duration and impact of outages on customers.

All OT must be approved in advance and is managed and monitored on a regular basis. Planning assumptions are determined by each line of business based on internal review of previous trends, work requirements, outages, and customer or project requirements.

Anticipated OT usage is captured in workforce plans as a percentage of all hours forecast to be worked. Usage rates are based on historical trends specific to the type of work to be performed and vary across job types and lines of business. The cost per hour of overtime will vary depending on the type of employee performing the work, as well as when the overtime is performed.

Hydro One's OT policy, including rates, was assessed by an independent expert, Mercer (Canada) Limited (Mercer), as part of its compensation benchmarking study. Mercer found that the company's OT policy is generally aligned with predominant market practice, including that the company's OT rates continue to be at or below the market median (see Exhibit E-06-01, Attachment 2, section 5, page 20).

Resourcing and OT considerations in executing the capital and operations and maintenance (O&M) work programs for both Transmission and Distribution are further described in the work execution exhibits (TSP Section 2.11, and DSP Section 3.10 and Exhibit E-03-05).

3.0 WORKFORCE PLANNING PROCESS & ANTICIPATED FTE LEVELS FOR THE RATE PERIOD

Effective planning is essential to forecast the workforce mix required to safely and cost efficiently execute Hydro One's day-to-day operations and complete its investment plan. Workforce planning is a multi-phase and collaborative effort across the organization. The process begins with each line of business determining the number of employees required to execute the investment plan based on forecasted work. The plans determine whether the existing workforce must be increased or decreased and where external resources may be needed. Workforce plans are refined through a series of review and challenge sessions at multiple levels of the company to optimize the resource strategy that is ultimately submitted to the Board for approval as part of the Business Plan.

As noted above, the collective agreements between Hydro One and the PWU and SUP impact workforce planning. The collective agreements originate with Ontario Hydro, which is the predecessor company that was split into five entities in 1999. Changes to the comprehensive terms of these agreements are negotiated through the collective bargaining process. Among the terms of these agreements are:

- selection language: provisions relating to candidate qualifications for vacancies/job competitions;
- voluntary and involuntary separation protocols and entitlements;

- provisions pertaining to scheduling, hours of work, overtime; and
- a description of work jurisdiction and contracting provisions.

Enhancements to Hydro One's workforce planning process have contributed to the company's ability to optimize required resources in the context of an increasingly complex planning environment driven by a growing investment plan. This supports the efficient delivery of capital and operating work, while promoting the prudent use of resources and helping manage costs for customers.

Hydro One carefully plans its resourcing requirements to determine what types of internal resources and external resources (contractors) are required to execute its work plan in a safe, cost-effective and timely manner. As shown in figure 5 below, the planning framework considers the operational needs of Hydro One and its lines of business, the Investment Plan and OEB direction to develop a consolidated business plan which includes FTE planning assumptions.

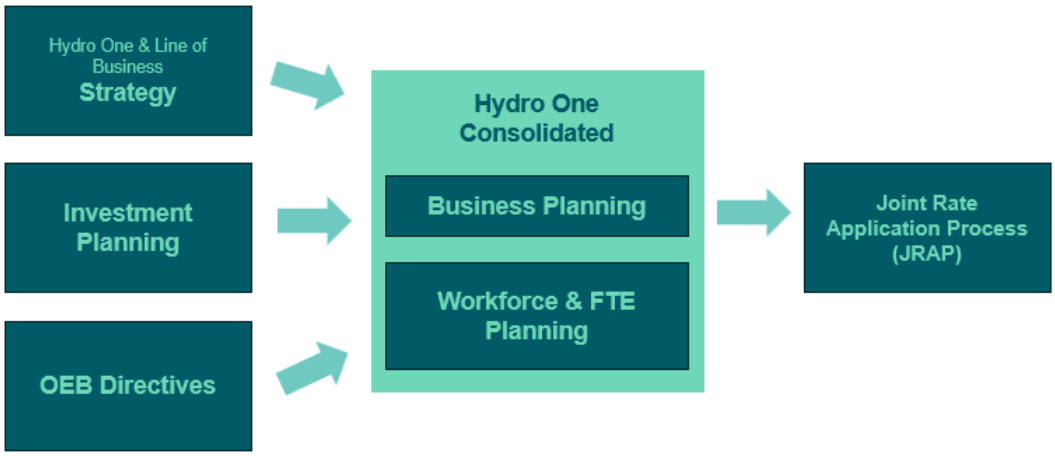

Figure 5: Planning Framework

Hydro One has established a 2028-2032 Investment Plan which will entail significantly increased levels of work for the period. To forecast the size and composition of workforce

and external resources required to execute the Investment Plan, Hydro One engaged in a multi-stage resource planning process to evaluate its existing staffing levels, assess resourcing options available, and develop the preferred option appropriate for each line of business. In conjunction with its annual business planning cycle, the company will continue to update its workforce plan annually throughout the rate period in response to any variations in conditions impacting workforce needs.

Hydro One's overall compensation costs are managed, in part, through careful resource planning, and the optimization of existing internal resources. The plan leverages Hydro One's workforce flexibility, including: the efficient assignment of work to existing staff; increased use of casual labour; and contracting work where appropriate and consistent with the terms of collective agreements.

3.1 APPROACH TO WORKFORCE PLANNING

Hydro One's resource planning decisions are driven by customer-focused outcomes, safety, reliability, efficiency and cost-effectiveness. The size of Hydro One's regular workforce corresponds to on-going work requirements, and incremental work is staffed efficiently using a mix of regular, casual, temporary and external resources as required.

The planning process to identify the forecasted workforce required to complete the Investment Plan and ongoing operations for the 2028-2032 planning period followed three phases:

1. Line of business Workforce Development Planning;
2. Review and Challenge Sessions; and
3. Board approval.

The workforce planning process began with each line of business assessing its requirements at the FTE level. Lines of business considered many factors and requirements in forecasting their workforce size and mix, including:

- **Work to be Performed** –The achievements and budget, specific to each line of business as detailed in their investment plans.

- **Cost** – Minimizing labour costs while maintaining safety, efficiency and compliance with collective agreements.
- **Duration of Work and Timelines** – The length of the work, and preferred timeline for completion. External delivery may be appropriate where work is temporary in nature.
- **Location of Work** – Assets and customers are spread across the province. Often, work to be performed is essential and must be performed locally and therefore cannot be relocated or centralized. Large segments of Hydro One's workforce must work in various locations and conditions, and can be deployed across the province as required to service customers, address trouble calls and restore larger-scale outages.
- **Complexity/Specialization** – Highly specialized or complex work that is not foundational to electrical grid operations, or is required only intermittently, may be contracted to minimize recruitment and training costs and access specialized expertise (e.g., building design). Hydro One also performs select work in-house to maintain internal expertise, with resources redeployed as needed.
- **Specialized Equipment** – Certain work requires investment in specialized vehicles and equipment with associated capital, training, maintenance, and other costs. These costs may warrant using external firms with greater specialization and higher utilization factors.
- **Technical, Security, and Risk-related Considerations** – Work requiring internal oversight, such as cybersecurity for critical infrastructure, may warrant additional regular FTEs to support risk mitigation and incident prevention. Certain work may also be retained in-house to maintain oversight, control and service standards.

Each line of business developed an initial workforce plan that was refined through collaboration and consultation with Human Resources and management. The collaboration supports a constructive dialogue on the proposed plan, including clarifying assumptions, assessing overall requirements, and identifying potential opportunities for alignment and efficiency. This allowed for discussion of the rationale for any proposed

workforce increases and confirmation that staffing decisions are aligned with overall operational and financial objectives.

Workforce plans continued to be refined as required and were incorporated into the consolidated Business Plan for Board approval.

As part of the annual business planning process, workforce plans are reviewed annually to reflect changes in investment priorities, operating conditions and workforce requirements.

The company's rigorous approach to workforce planning has resulted in a workforce mix designed to safely, efficiently, and cost-effectively deliver planned investments and ongoing operations while maintaining a safe and reliable grid.

3.1.1 REFINEMENTS TO THE PROCESS

Since the prior rate period, Hydro One has made two important refinements to its workforce planning process: earlier planning and improved use of data and analytics. Earlier engagement by lines of business provided additional time to identify and address risks and opportunities, both within the line of business and in collaboration with Human Resources and management. The Company has also hired a dedicated Manager of HR Reporting and Analytics responsible for compiling, tracking and analyzing workforce data, which results in strengthened, data-driven workforce planning and decision-making. These process improvements informed the development of the 2028–2032 workforce plan.

4.0 PLANNED AND ACTUAL FTES

This section presents the company's planned FTE levels for the 2028-2032 planning period based on the results of the workforce planning process. The actual and planned FTEs for the 2023-2027 period are also provided.

Table 2 provides the historical actual FTEs for 2023-2025, the planned FTE levels for 2026-2027, and the forecasted FTEs for 2028-2032.

Table 2 - Actual and Planned FTEs for 2023 to 2032

Type	Representation	2023 Actual	2024 Actual	2025 Actual	2026 Plan	2027 Plan	2028 Plan	2029 Plan	2030 Plan	2031 Plan	2032 Plan
Regular	MGT/ NR	786	849	813	902	887	968	1,000	1,011	1,015	1,015
	Society	1,828	1,946	1,907	1,996	1,994	2,132	2,211	2,237	2,249	2,251
	PWU	3,887	4,062	4,095	4,342	4,489	4,588	4,674	4,703	4,722	4,724
	Total Regular	**6,502**	**6,857**	**6,815**	**7,240**	**7,370**	**7,689**	**7,886**	**7,952**	**7,986**	**7,989**
Casual	PWU Hiring Hall	1,047	1,033	749	931	975	1,319	1,429	1,499	1,526	1,466
	CUSW	1,025	1,029	941	1,011	938	1,247	1,184	1,247	1,225	1,159
	BTUs (EPSCA)	534	531	459	453	490	630	621	637	629	622
	Total Casual	**2,607**	**2,593**	**2,149**	**2,395**	**2,404**	**3,196**	**3,234**	**3,383**	**3,380**	**3,247**
	Temporary	**196**	**219**	**189**	**140**	**94**	**78**	**78**	**76**	**74**	**74**
Total		**9,305**	**9,669**	**9,153**	**9,774**	**9,868**	**10,963**	**11,198**	**11,410**	**11,440**	**11,310**

The costs associated with the FTE levels in Table 2 above are detailed in the Compensation Cost Table and explanatory notes appended to exhibit E-06-01 (Attachments 1A and 1B). The Compensation Cost Table includes actual compensation costs for 2023 to 2025, planned costs for 2026 and 2027, and forecast costs for 2028 to 2032.

During the 2023-2027 period, Hydro One experienced work volumes, timing and scope which differed from plan, largely consisting of an increased volume of demand investments causing the reprioritization of certain investments (see TSP Section 2.9, DSP Section 3.9 and GSP Section 4.9). The actual and planned FTE levels for the 2023-2027 period reflect variances from the workforce plan filed in EB-2021-0110. The main drivers for the variances are FTE increases driven by unplanned, non-discretionary scope and hiring commitments under Letters of Understanding[8] between Hydro One and its union partners, partially offset by certain FTE reductions due to deferred work. The main variance drivers are the same for all years in the period. Unplanned, non-discretionary scope which was

[8] Letters of Understanding reflect negotiated arrangements whereby Hydro One may have agreed to additional staffing capacity while also achieving efficiencies and workforce flexibilities that support operational effectiveness and productivity.

not included in the EB-2021-0110 application includes both new and incremental work under the Externally Driven Work, Cable Locates, Joint Use, AMI 2.0 and Broadband programs.

The 2028-2032 FTE forecast incorporates the resources required to execute the capital, maintenance and operating programs that comprise Hydro One's investment plan over that period.

The company has demonstrated the ability to recruit and develop talent through various means, including established apprentice and new graduate programs, mass hiring processes, and the progression of experienced casual and temporary employees into regular roles. These recruitment channels provide Hydro One with the ability to recruit, develop, and onboard employees at scale, including the hiring of large cohorts through apprentice, new graduate, and enterprise-wide recruitment initiatives. This capability, together with Hydro One's ability to coordinate hiring across multiple lines of business, supports the company's capacity to fill critical positions required to execute the planned work program.

The 2028–2032 forecast includes a relatively larger increase in FTEs between 2027 and 2028, the majority of which are casual employees, followed by a smaller increase over the 2029–2032 period, consistent with forecast work requirements. The initial step change in FTEs corresponds to a significant initial expansion in planned capital activity during the rate period. This includes an increase in the forecast work program, sustained customer-driven demand and growth-related work.

From 2027 to 2028, the investment plan increases by approximately 36% (from approximately $4.6 billion to approximately $6.2 billion). During the same period, total FTEs increase by 11%. The majority (approximately 72%) of this workforce growth is comprised of casual resources, with the remaining growth primarily attributable to regular employees. This workforce mix provides capacity to support the increased work volumes while preserving flexibility in resource deployment.

Between 2029 and 2032, the investment plan grows by approximately 5% annually. Over the same period, the workforce plan results in only a cumulative FTE increase of approximately 3%, with most of this increase (approximately 86%) being regular resources. This workforce mix reflects the transition from an initial mobilization phase to a steadier-state level of resourcing necessary to sustain the investment portfolio.

Cumulatively, over the 2027-2032 period, the investment plan is forecasted to grow by 60%, reflective of increased levels of mandated System Access and System Service investment requirements. From 2027 through to the end of 2032, the company forecasts an overall FTE increase of 14.6%, with approximately 58% of these FTEs being casual resources. Hydro One's workforce plan reflects a continued reliance on casual resources to provide flexibility and be efficient in addressing increased work requirements, while supporting the execution of the company's planned investments over the long term.

Figure 6 below shows the actual/planned FTE trend and the investment plan trend from 2023-2032.

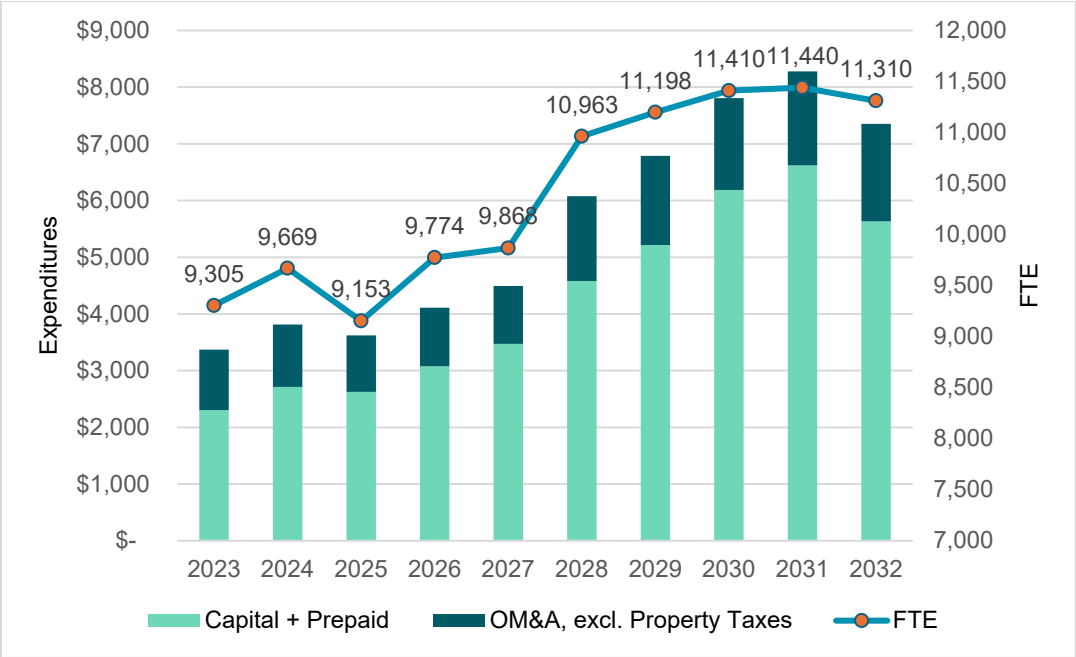

Figure 6: FTE Levels and Investment Plan Spend[9]

As shown in Table 3 below, the ratio of FTEs per million dollars of spend is projected to decline from 1.76 in 2028 to 1.54 in 2032, despite significant growth in planned expenditures. Hydro One's FTE forecast demonstrates efficiencies in being able to support increased volumes of work and spend under the 2028-2032 investment plan.

Table 3 - FTE per Million Dollars of Investment

Metrics (FTE / Total $ M)	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Total	2.73	2.52	2.51	2.32	2.15	1.76	1.65	1.46	1.38	1.54

While the company's overall forecasted FTE increase reflects enterprise-wide investment activity, the growth is not uniform across the organization. Most of the FTE growth is driven

[9] Total FTEs include both Distribution and Transmission-specific FTEs (sections 4.1 and 4.2) and the Enterprise Support and Common Corporate FTEs (section 4.3) allocated to Distribution and Transmission, consistent with the methodology used and described in Appendix 2-K.

by specific lines of business with direct accountability for delivering the company's largest and most resource-intensive programs.

The following sections provide a summary of forecasted FTE changes, and key workforce drivers by line of business, beginning with Distribution and Transmission, followed by Enterprise Support and Enabling Functions, and Common Corporate areas that support delivery across the organization.

4.1 DISTRIBUTION PLANNED FTES

The Distribution investment plan increases by approximately 61% from 2027 to 2028 (from approximately $1.8 billion to approximately $3.0 billion), followed by annual growth of approximately 4% from 2029 to 2032. Distribution's planned FTE levels increase over the 2028–2032 planning period to support higher work volumes; however, the rate of FTE growth is materially lower than the rate of growth in the investment plan.

The FTEs across the Distribution portfolio are expected to remain relatively flat from 2027 to 2028. While the overall work program continues to grow, a significant portion of resources supporting Broadband-related work in 2027 are planned to be redeployed to core Distribution programs in 2028 as Broadband activity begins to decline. This redeployment enables the portfolio to absorb increasing work volumes and workload requirements in 2028 without any material increase in headcount. As a result, the workforce baseline established at year-end 2027 is sufficient to deliver the 2028 work program. Incremental FTE growth is therefore phased over the remainder of the rate period (2029-2032) to align with the sustained increase in work program growth and complexity once the capacity available through Broadband resource redeployment has been fully utilized.

Incremental FTEs will support both the execution of Hydro One's long-standing core work programs and the delivery of new and expanding major capital projects and programs, including work such as underground cable replacement, clustered grid hardening, secondary system electrification and voltage conversion. While the company has

historically maintained a consistent workforce to support ongoing operations and maintenance activities, the scale, complexity and volume of work is planned to increase materially over the rate period due to both system needs and new program requirements. As a result, workforce growth and flexibility are necessary to ensure the company can continue to deliver its core obligations safely and reliably, while also executing an expanded and more complex portfolio of capital work.

Most of the Distribution FTE increase is comprised of casual resources which gives Hydro One flexibility to increase or decrease workforce in response to factors influencing the volume and timing of work. These key work programs are inherently labour-intensive and are executed over large geographic areas, often with variability in volume, timing, and access requirements. As a result, the associated workload is well-suited to a flexible resourcing model that can be scaled in response to program demands. The use of casual resources enables the company to efficiently mobilize crews to deliver these programs while maintaining cost discipline and avoiding sustained increases in fixed workforce levels.

The required regular resources support work of an ongoing nature in roles such as field leadership, program and project execution oversight, quality assurance, planning & scheduling, and reporting.

The Distribution planned FTEs will support an increasing volume of work. Table 4 presents the increase in planned accomplishments compared to the prior rate period. Approximately 70% of the Distribution work in the 2028-2032 investment plan is unitized.

Table 4 - Distribution accomplishments relative to prior rate period

JRAP 2023 – 2027 Actuals/Planned	JRAP 2028 – 2032 Planned	Increase % (Actuals/Planned to JRAP28 Plan)
12,777,653	16,546,741	26.5%

For the remainder of the Distribution Lines work program that is not unitized, project-based work represents a significant share of planned expenditures. While the overall number of

projects remains relatively stable from plan to plan, the project mix has shifted considerably toward larger, more complex work. Specifically, the number of projects valued at less than $1M has decreased by 59%, and projects in the $1M to $5M range have declined by 18%. In contrast, the number of projects valued between $5M and $10M has increased by 87%, while projects in the $10M to $100M range have increased tenfold. This shift toward larger projects has resulted in a threefold increase in funding requirements for Distribution Lines major and sustainment projects. As the portfolio becomes increasingly concentrated in higher-value projects, the associated scope, complexity, stakeholder coordination, and operational execution requirements increase significantly, driving greater planning and delivery effort.

The FTE increases required to support the Distribution investment plan and associated growth in work volumes are discussed below at the line of business level.

Distribution Lines

The forecasted FTEs in the Distribution Lines portfolio are expected to increase by approximately 17**%** (233 FTEs) from 2027-2032 made up of 160 casual FTEs and 73 regular FTEs. The reliance on casual resources reflects a deliberate approach to align workforce levels with the timing, variability, and evolution of the work program. The increased volume of accomplishments in Distribution Lines is driven by a combination of regulatory compliance obligations, reliability and safety requirements, demand driven system growth, and the need to address previously deferred work. The labour effort required to deliver the 2028–2032 work program, measured in estimated hours, is expected to be more than double that of the previous rate period. The increase in planned FTEs is primarily attributable to both higher volumes of existing work, consistent with growing system needs, and the introduction of new program scope, including Vulnerability Assessment and System Hardening (VASH). The anticipated scale, complexity, and specialized skill requirements to execute this work are expected to increase resourcing needs. The planned use of casual FTEs provides flexibility as scope definition and delivery approaches are finalized.

Distribution Work Management

FTEs in Distribution Work Management are expected to increase by approximately 16% from 2027-2032, made up of 33 casual FTEs and 46 regular FTEs. This growth is attributable to supporting similar work as described above in Distribution Lines.

The Distribution Work Management team supports program and project execution oversight, critical project management, contract management functions and continuous improvement initiatives that will support the execution teams ahead of and throughout the significant increase in volumes of work. As work volumes increase and additional contractor resources are engaged to support execution, corresponding increases in contract management, project oversight, and quality assurance functions are required. These resources are responsible for contractor governance, performance monitoring, compliance oversight, and ensuring work is delivered in accordance with Hydro One's standards, thereby supporting the effective execution of the capital program. Beyond this core capacity, these functions can leverage external resources to address incremental or project-specific workload requirements.

Distribution Operations Management

The Distribution Operations Management team is forecasting growth of approximately 24% from 2027 – 2032, consisting of 6 casual FTEs and 23 regular FTEs. This group will support the execution team with work related to quality assurance, process improvement, and regulatory compliance.

Design Services

In Design Services, total FTEs decrease by approximately 6% from 2027-2032. This is primarily attributable to a decrease in casual resources (44 FTEs), while regular resources remain relatively stable. Demand for Area Distribution Engineering Technician resources is expected to increase, driven by growth in a combination of regulatory compliance obligations, reliability and safety requirements, demand driven system growth, and the need to address previously deferred work. Rather than increasing FTEs to address this demand, Hydro One has identified an opportunity to optimize existing resources. A

projected surplus of metering staff following the completion of the AMI 2.0 program are planned to be redeployed to support design and estimating activities. Information regarding Distribution's approach to executing its growing investment plan is detailed in DSP Section 3.10 – Capital Work Execution and Exhibit E-03-05 Distribution O&M Work Execution Strategy.

4.2 TRANSMISSION PLANNED FTES

The Transmission investment plan is increasing by approximately 18% from 2027 to 2028 (from approximately $2.7 billion to approximately $3.2 billion), followed by annual growth of approximately 5% from 2029 to 2032. Transmission's planned FTE levels increase over the 2028–2032 planning period to support higher work volumes; however, the rate of FTE growth is materially lower than the rate of growth in the investment plan.

The increase in planned FTEs over the 2027 to 2032 period is primarily driven by an increase in work volumes in Transmission Lines and Station Construction.

This resourcing profile reflects the nature of Transmission work, where a significant portion of the incremental workload is project-based, time-bound, and variable in volume. The significant reliance on casual resources enables the company to scale execution capacity in response to increased work program demands. The relatively minor increase in regular employees ensures the company retains core expertise, oversight, and continuity.

The overall increase in workforce levels is aligned with the step change in the capital work program, which ramps up in 2028 and continues over the rate period. This step change reflects a material expansion in the scale, complexity, and volume of Transmission work, including the execution of large, multi-year capital projects and system investments required to maintain reliability, support growth, and meet evolving customer and regulatory requirements. As the work program increases in both size and complexity, additional resources are required to effectively plan, manage, and execute these activities.

Investment plan growth is driven by increasing work volumes over the rate period. Table 5 presents the increase in planned accomplishments relative to the prior rate period. Approximately 50% of Transmission work is unitized.

Table 5 - Transmission accomplishments relative to prior rate period

JRAP 2023 – 2027 Actuals/Planned	JRAP 2028 – 2032 Planned	Increase % (Actuals/Planned to JRAP28 Plan)
25,384	32,490	28%

For the remainder of the Transmission work program that is not unitized, project-based work represents a significant share of planned expenditures. While the overall number of projects remains relatively stable from plan to plan, the composition of the portfolio has shifted toward a greater proportion of growth-related investments. Compared to traditional sustainment work, these projects involve a broader range of external stakeholders and dependencies, including customers, regulators, municipalities, landowners, and contractors. This evolving project mix increases the need for coordination, project controls, governance, and oversight to manage delivery risks and support successful execution of the work program.

The FTE increases required to support the Transmission investment plan and associated growth in work volumes are discussed below at the line of business level.

Transmission Lines

Transmission Lines has forecasted an FTE increase of approximately 36% from 2027 to 2032, comprised mainly of casual resources (342 FTEs) and a minor increase in regular employees (5 FTEs).

The forecasted increase in resources is driven by the volume of core Transmission Lines work programs, including Wood Pole Structure Replacement, Shieldwire and Insulator Replacement, and Steel Structure Coating. These programs are essential to maintaining the integrity, safety, and reliability of the transmission system. These key work programs

are inherently labour-intensive and are executed over large geographic areas, often with variability in volume, timing, and access requirements. As a result, the associated workload is well-suited to a flexible resourcing model that can be scaled in response to program demands. The use of casual resources enables the company to efficiently mobilize crews to deliver these programs while maintaining cost discipline and avoiding sustained increases in fixed workforce levels.

Station Construction

Station Construction is forecasted to increase its FTEs by approximately 34% from 2027 to 2032, comprised entirely of casual resources (301 FTEs). The increase in FTEs is driven by the execution of major station capital work, including the construction of new transmission stations and a range of component replacement initiatives within existing stations.

New station builds are required to accommodate system growth, increased demand, and the integration of new connections. New station builds typically involve multi-year construction efforts, coordination across multiple disciplines, and significant field execution requirements.

Component replacement projects within existing stations address aging infrastructure and asset condition risks. The nature of this work is project-based, site-specific, and subject to variability in timing and execution requirements. As a result, the use of predominantly casual resources enables the company to efficiently scale construction capacity to meet increased work volumes, while maintaining flexibility and limiting the growth in fixed workforce costs.

Stations Services

From 2027 to 2032, Station Services is planning an approximate 6% increase in regular resources (50 FTEs). This increase in FTEs is focused on the Electrical Maintenance and Protection & Control teams, which are critical to maintaining system reliability and supporting capital execution. The increase in planned FTEs is driven by a material

expansion in commissioning related Protection and Control (P&C) activities associated with a higher volume of station refurbishments, new stations, and new or refurbished transmission lines. These projects require non-discretionary, safety-critical work such as protection scheme testing and configuration, on-site commissioning and cutovers, and post-commissioning compliance documentation.

The growing number of concurrent station and line projects also increases the need for coordinated outage planning and multi-station commissioning. In addition, heightened testing, verification, and regulatory documentation requirements add incremental P&C hours per project, resulting in a sustained increase in required FTEs. Growth in system demand and asset renewal requirements has resulted in a larger and more complex portfolio of projects, each of which generates mandatory downstream commissioning work at stations. Further, the need to address accumulated sustainment and refurbishment work that was deferred in earlier periods, combined with heightened regulatory and compliance expectations related to system reliability, safety, and documentation, increase the volume and complexity of commissioning activities requiring support from Station Services resources. Collectively, these factors result in a sustained increase in commissioning workload that underpins the higher volume of planned accomplishments and necessitates a corresponding increase in planned FTEs.

Project Delivery, Strategic Project Delivery, Project Management and Transmission and Stations Engineering

The Project Delivery, Strategic Project Delivery, Project Management, and Transmission & Stations Engineering functions are expected to remain relatively flat over the rate period, as these teams continue to support work execution through a stable core workforce.

These functions maintain a baseline of regular employees to perform core, ongoing activities that require internal expertise, continuity, and integration with enterprise processes. This includes responsibilities related to planning, oversight, engineering design, and project governance, which are critical to the safe and effective delivery of the capital program.

Beyond this core capacity, these functions can leverage external resources to address incremental or project-specific workload requirements. This approach enables the company to maintain internal capability while flexibly scaling delivery capacity as needed, supporting efficient execution of the work program while managing overall cost and workforce levels.

Information regarding Transmission's approach to executing its growing investment plan is detailed in TSP Section 2.11 – Capital Work Execution and Exhibit E-02-05 Transmission O&M Work Execution Strategy.

4.3 ENTERPRISE SUPPORT AND COMMON CORPORATE FUNCTIONS

Enterprise support and common corporate functions provide enterprise-wide services that enable the safe and efficient delivery of Hydro One's Transmission and Distribution operations and the 2028 – 2032 Investment Plan. These functions deliver centralized services across the organization, promoting consistency in policy, process and practice while enabling efficient use of resources. Planned FTE increases over the rate period support the increased work volumes associated with the 2028-2032 Investment Plan and are discussed below by function.

4.3.1 ENTERPRISE SUPPORT

Engineering

Engineering FTEs are forecasted to increase by approximately 20% (29 regular FTEs) from 2027 to 2032. This growth is driven by increasing complexity in asset planning, design, and execution, as well as heightened regulatory expectations related to system reliability, safety, and long-term infrastructure stewardship. Expanded internal engineering capacity is essential to support the timely development and delivery of capital programs, lifecycle asset management, and integration of evolving technical standards.

The use of regular resources reflects the nature of engineering work, which is ongoing, knowledge intensive, and requires sustained ownership of system planning, design standards, and technical decision-making. Engineering functions are responsible for the

development and application of design specifications, asset strategies, and technical governance frameworks that must be consistently maintained and applied across the organization. These resources support the development and delivery of projects, typically at the front end of the work, and while the work program is growing over time, much of the additional effort for these resources will be required at the start of the rate period

Planning and Transmission System Planning & Large Customer

The Planning and Transmission Planning & Large Customer teams are planned to increase by approximately 30% (56 regular FTEs) from 2027 to 2032.

This increase is planned to support growing demand because of an increased investment plan, and to ensure continuity of service. These teams are responsible for core planning activities that are foundational to the operation and development of the grid. This includes the identification and assessment of long-term system needs, development of integrated transmission plans, and evaluation of system performance under evolving load and generation conditions. In addition, these functions play a critical role in supporting large customer connections, including coordinating technical requirements, assessing system impacts, and ensuring timely and reliable service to customers.

Much of the work consists of mandatory work related to customer connections which is subject to the Transmission System Code, as well as IESO-driven work arising from Regional Planning and Bulk System Planning, which investments are significant in scale and complexity and underpin economic growth and mandated system expansion needs. The volume of work across these functions is expected to increase over the 2028 to 2032 planning period.

The work also involves ongoing engagement with regulatory bodies, system operators, customers, and internal stakeholders to support investment planning, system expansion initiatives, and regulatory filings. This includes aligning system plans with broader policy, electrification, and growth objectives, and developing planning evidence and supporting regulatory approvals.

Planning must introduce new programs to comply with a growing landscape of regulatory requirements including the OEB's Vulnerability Assessment and System Hardening requirements (EB-2024-0199), Non-Wires Solutions requirements (EB-2024-0118), and Reliability and Power Quality requirements (EB-2021-0307). Furthermore, Planning is introducing new programs in response to customer needs and preferences, as well as industry standards and codes, and must be ready to respond to evolving policy, regulatory, technology and system requirements.

Planning functions operate at the forefront of challenges that are not unique to Hydro One but are increasingly affecting the broader electricity sector: aging infrastructure, environmental-related risks, the pace of the energy transition, and changing customer expectations which are compounding the complexity and work volume of the planning environment. As such, this work is not only increasing in volume, but also in complexity. To respond to this unprecedented and mandatory work program growth and complexity, Planning's current capacity and specialized capabilities must be expanded.

As the volume and complexity of the investment plan increases, these functions must also support enhanced analysis, modelling, and coordination activities to ensure that system development is optimized, compliant, and delivered efficiently. The increase in FTEs reflects the need to sustain these critical planning activities while supporting a growing and more complex portfolio of work across the system. Regular FTEs are necessary to fulfil these functions which require a highly specialized internal workforce to support regulatory compliance, stakeholder engagement, and the effective development and execution of asset management and engineering plans.

System Operations (System Control)

System Operations is forecasting a 24% increase in FTEs from 2027 to 2032, comprised of 61 regular FTEs.

This increase in FTEs is required to manage growing work volumes driven by system expansion, increased operational complexity, and heightened regulatory and compliance

requirements. As the system continues to grow in size and complexity, additional internal System Operations capacity is necessary to ensure safe and reliable real-time operations, maintain compliance with evolving reliability standards, and support timely and effective response to system events.

System Operations functions include continuous system monitoring, outage coordination, switching operations, contingency management, and real-time decision-making to maintain system stability and performance. These activities are critical to ensuring that electricity is delivered safely and reliably to customers and that the system is operated within established technical limits.

In addition, System Operations is responsible for compliance with applicable reliability standards and operational protocols, including those related to system security, emergency response, and coordination with the Independent Electricity System Operator (IESO) and other market participants. Increasing regulatory expectations and system complexity require enhanced monitoring, analysis, and coordination capabilities to ensure ongoing compliance and operational resilience.

The planned increase in regular resources reflects the continuous, specialized, and high-accountability nature of System Operations work, which requires sustained expertise, operational continuity, and clear responsibility for critical system operations.

Customer Service & Billing Operations

Customer Service and Billing Operations plans an increase of approximately 10% from 2027 to 2032, comprised of an increase of 43 regular resources and a decrease of four casual resources.

The initial increase in staffing is driven by customer growth, contact volumes, and the need to maintain service levels as Hydro One’s investment plan expands. Sustained customer volumes and increased service complexity are expected to result in higher volumes of

billing transactions, exceptions, adjustments, settlement activity, and customer inquiries over time.

These additional resources are required to preserve service quality, maintain compliance, and support accurate and timely customer interactions. The planned reduction by the end of the rate period reflects the stabilization of workload following the initial increase, as well as ongoing efficiency improvements and process optimization within the function.

Forestry Services

Forestry Services is forecasted to increase by approximately 8% from 2027 to 2032, comprised mainly of casual resources (52 FTEs) and a minor increase in regular resources (10 FTEs).

The forecasted increase in resources is driven primarily by vegetation maintenance work that was reprioritized for execution during the 2028-2032 planning period as funding was directed to higher priority activities during the 2023-2027 rate period. Addressing this work in the 2028-2032 planning period is necessary to maintain compliance with vegetation management standards, support system reliability and reduce risk associated with vegetation-related outages.

Forestry Services work includes vegetation inspection, tree trimming and removal, right-of-way maintenance, and hazard mitigation activities across a large and geographically dispersed service territory. These activities are essential to maintaining safe and reliable system operations and supporting the execution of Hydro One's broader investment and sustainment programs.

Supply Chain

From 2027 to 2032 Supply Chain will increase their regular resources by approximately 11% (25 FTEs). The planned increase of resources is driven by growth in material handling, inventory management, and logistics requirements associated with the company's expanding Transmission and Distribution work programs. This increase will support

Distribution volumes by ensuring the timely receipt, storage, and delivery of materials to field crews for projects, while maintaining continuity of critical inventory. Additional FTEs will support the implementation of a Transmission inventory management program and enhanced field support model, aligned with major projects.

Fleet Services

From 2027 to 2032 Fleet Services will increase their regular FTEs by approximately 12% (22 FTEs). This increase in FTEs is driven by significant growth in capital investment and associated increases in fleet and equipment volumes over the 2028 – 2032 planning period to support the growing work program. The planned FTE growth is necessary to maintain operational standards, support the safe and reliable operation of an expanding and modernized fleet, and ensure that employees have appropriate equipment to do their job in a safe and effective manner. Hydro One expects to increase the fleet by approximately 1200 units, and 330 heavy units, across the planning period to support the work program.

Digital Technology Solutions

From 2027 to 2032 Digital Technology Solutions (DTS) will increase FTEs by approximately 18%, comprised of 85 regular resources. The use of regular resources within DTS reflects the nature of the work performed. DTS functions are responsible for the design, maintenance, and governance of enterprise systems, data platforms, and cybersecurity controls, all of which require continuity and institutional knowledge.

This increase in FTEs is required to support Hydro One's expanding investment program, increasing data and system complexity, and evolving regulatory and operational requirements. Growth in data, analytics and AI capabilities is necessary to manage data systems, rising data volumes, support evidence-based planning and operational decision-making and meet regulatory and reporting expectations, while ensuring appropriate governance and oversight. Security operations remain a priority where capacity is required to further advance cyber security threat detection, management activities, and response, where incidents are expected to continue to rise. In parallel, additional internal capacity

within enterprise applications, including SAP, is required to strengthen system stewardship, reduce operational risk, and improve long-term cost and performance management by rebalancing reliance on external service providers.

Collectively, these FTE increases support system reliability, data integrity, cyber and operational risk management, and the sustained delivery of mission-critical digital services throughout the rate period.

4.3.2 COMMON CORPORATE FUNCTIONS AND SERVICES (CCF&S)

CCF&S provide enterprise-wide governance, oversight, and enabling capabilities that support the safe, reliable and efficient execution of Hydro One's Transmission and Distribution work programs. By centralizing these activities, the company can ensure standardized and consistent application of policy, procedure and practice, and efficient use of resources to effectively support delivery of the 2028-2032 investment plan. CCF&S planned FTE levels increase over the 2028–2032 planning period to support the increased work volumes within the company's 2028-2032 investment plan.

Corporate Affairs

The Corporate Affairs team plans an approximate 13% increase in FTEs from 2027-2032 comprised of 8 regular resources. The forecasted increase is in response to the expanding scale, pace and complexity of Hydro One's capital investment plan, and the corresponding rise in engagement, regulatory and communications requirements. As system investments accelerate and project delivery activity intensifies across an increasingly broad and diverse geographic footprint, the volume, frequency and sophistication of stakeholder interactions will materially increase.

In particular, the company anticipates a sustained rise in obligations related to community, including early and ongoing consultation, partnership development, and issue resolution, all of which require dedicated, specialized capacity. At the same time, evolving regulatory expectations, greater information demands, and heightened public scrutiny necessitate

more robust, timely and data-driven communications, including to support transparency and maintain public trust.

Additional internal resources will also enable greater coordination across business units, ensuring consistent messaging, proactive issues management, and alignment between project delivery, regulatory filings and stakeholder outreach. This includes supporting more complex, concurrent projects and aligning capacity with industry practice for utilities undertaking comparable capital programs. Without this incremental capacity, there is an increased risk of fragmented and less effective engagement, slower response times and project delays, which could ultimately impact cost, schedule and customer outcomes.

Finance

The finance team is forecasted to increase headcount by approximately 5% from 2027 to 2032 comprised of 7 regular FTEs. This increase is required to support the greater volume and complexity of business activity associated with the expanded Investment Plan. As capital and operational activities grow across the organization, Finance functions must scale accordingly to provide budgeting, forecasting, financial reporting, and cost control support.

Regulatory

The Regulatory team is expected to increase its regular headcount by approximately 27% from 2027-2032, comprised of 11 FTEs. Key drivers of this increase include additional OEB applications and annual updates, an expanding pipeline of transmission project approvals (leave-to-construct, expropriation, licensing, and rate proceedings), and increased compliance requirements, including IESO MACD obligations.

Enhancing internal regulatory capacity supports timely, high-quality submissions, reduces execution and compliance risk, and ensures the organization can effectively manage expanding regulatory demand while maintaining service levels.

Human Resources

The Human Resources function is forecasted to increase by 11 regular FTEs (approximately 5%) from 2027 to 2032. This increase reflects the requirements of a growing workforce, expanding operational scope, and increasing organizational complexity driven by Hydro One's investment plan. As the scale of capital and operations activities increases, corresponding growth in workforce levels necessitates additional HR capacity to effectively support recruitment, onboarding, and workforce integration activities.

In addition, the function is required to manage a higher volume and complexity of employee relations matters, support enhanced workforce planning through more robust, data-driven analysis, and improve alignment between staffing levels, forecast workload, and investment requirements. This includes supporting enterprise workforce planning processes and ensuring resource levels across the organization are aligned with the timing and execution requirements of the investment plan.

In parallel, the internalization of key people-strategy capabilities, such as organizational design, leadership development, and performance management supports improved cost effectiveness, continuity of service, and retention of institutional knowledge. These capabilities are critical to enabling workforce productivity and supporting the effective execution of a significantly expanded and more complex work program.

5.0 CONCLUSION

Hydro One's workforce planning process is robust and comprehensive, ensuring that resourcing decisions are aligned with business needs, execution timelines, and effective cost management. The process has resulted in a forecasted workforce size and composition that is required to efficiently execute the company's significantly growing investment plan over the 2028-2032 planning period. The number of FTEs is increasing in alignment with increases to the forecasted volume of planned and demand work.

Hydro One continues to focus on resourcing efficiencies through upskilling current employees, leveraging data-driven analytics, and taking advantage of resourcing flexibility. Hydro One's workforce plan also reflects a deliberate labour strategy that leverages a mix of regular employees, casual resources, and contracted services. Regular employees provide the core capability required to safely operate, maintain, and support the electricity system on an ongoing basis, while casual resources provide flexibility to address fluctuations in work volumes and support efficient delivery of the investment plan. Contracted services are used selectively where appropriate to supplement internal resources, provide specialized capabilities, or support the execution of discrete work programs.

This workforce mix supports operational flexibility, cost-effective delivery, and the efficient execution of planned work, helping Hydro One maintain a reliable electricity system, complete required investments in a timely manner, and manage costs for customers over the long term.

PENSION AND OPEB COSTS

This Exhibit describes Hydro One's pension and other post-employment benefit costs (OPEB) for the 2028-2032 period, in respect of the Transmission and Distribution businesses, and the manner in which those costs have been forecasted for purposes of recovery. As pension and OPEB costs are an important part of the overall compensation that is provided to attract and retain skilled employees for the purpose of providing regulated service, Hydro One has historically been permitted to recover such costs through rates, including most recently for the Distribution business and for the Transmission business in EB-2021-0110. Hydro One's pension and OPEB costs over the test period have been appropriately forecasted in a manner consistent with prior OEB approvals and based on expert actuarial valuation.

1.0 PENSION COSTS OVERVIEW

Until January 1, 2016, the only Hydro One pension plan was a defined benefit plan (the DB Plan). Company contributions to the DB Plan are based on actuarial valuation reports, which must be performed by actuaries at least every three years. Forecasting for future years is based on such Tri-Annual Valuation reports and actual or projected levels of members and pensionable earnings as applicable.

As discussed under Section 2.3 below, Hydro One's pension plan would need to have a funded ratio of at least 105% calculated on a wind-up basis to be in a position to take a pension contribution holiday in a given year. Hydro One's DB Plan is 95% funded on a wind-up basis. Therefore, Hydro One is not in a position to take a pension contribution holiday and contributions cannot be reduced to zero in a given year.

Effective January 1, 2016, Hydro One introduced a second pension plan, which is a defined contribution pension plan (the DC Plan). The DC Plan is only available to persons who are not eligible to participate in the DB Plan. Members of the DC Plan have an option to contribute 4%, 5%, or 6% of their pensionable earnings into the DC Plan, with matching contributions by Hydro One up to an annual contribution limit. Exhibit E-06-01, sections

3.1.4, 3.2.4, and 4.2, provide further information regarding Hydro One's efforts to reduce pension costs.

2.0 DB PLAN

The following sections describe the DB Plan and its governance, the actuarial valuations which determine contribution rates under the DB Plan, cost recovery for the DB Plan, as well as DB Plan performance.

2.1 DB Plan Description and Governance

The DB Plan is a contributory, defined-benefit pension plan. The DB Plan is registered pursuant to the *Pension Benefits Act* (Ontario) and the *Income Tax Act* (Canada) and is not subject to income tax. Plan members include eligible represented employees of the Power Workers Union (PWU) and the Society of United Professionals (SUP), as well as non-represented Management Compensation Plan (MCP) employees, who were hired and met the eligibility requirements to join the plan no later than September 30, 2015, along with pensioners who were previously employees, and pensioners who are beneficiaries or surviving spouses of employees or pensioners.

The DB Plan covers Hydro One Limited and its subsidiaries including Hydro One Inc. Hydro One Inc. is the DB Plan sponsor and administers the pension assets and obligations of the DB Plan. The DB Plan therefore does not segregate assets into separate accounts for individual participating entities from the Hydro One group of companies, nor is the accrual cost of the DB Plan allocated to, or funded separately by entities within the consolidated group. Rather, Hydro One Networks Inc. and other subsidiaries of Hydro One Inc. are participants in the DB Plan. As such, while the DB Plan is accounted for as a defined benefit plan at the level of Hydro One Inc., for Hydro One Networks Inc. the DB Plan is accounted for as a defined contribution plan and no deferred pension asset or liability is recorded on Hydro One Networks' financial statements. This is consistent with pension accounting for utilities whose employees participate in the Ontario Municipal Employees Retirement System (OMERS) pension plan.

2.2 DB Plan Actuarial Valuation

As discussed earlier, for DB plans, there is a requirement to complete and file a full actuarial valuation at a minimum every 3 years. Management can, at its discretion, file these valuations more frequently. The Tri-Annual Actuarial Valuation report for the DB Plan as at December 31, 2024 (provided as Attachment 1 to this exhibit) establishes the contribution rate for 2025, 2026 and 2027. In September 2025, Hydro One filed this actuarial valuation with the Financial Services Regulatory Authority of Ontario (FSRA), formerly FSCO. Hydro One's next Tri-Annual Actuarial Valuation for the DB Plan is required to be prepared based on funding status and plan participation information as at December 31, 2027 and must be filed by September 30, 2028. The valuation results will depend on investment returns, changes in benefits, and actuarial assumptions.

The December 31, 2024 valuation showed that the DB Plan is in a deficit position of $429M on a wind-up basis[1] as of December 31, 2024.[2] Based on that valuation, starting on April 1, 2025, the required contribution rate for the DB Plan (employer normal actuarial cost as a % of payroll) was set at 7.6% of base pensionable earnings.

DB Plan pension cost in 2023, 2024 and 2025 was $69M, $75M and $68M, respectively. For the transmission business, this translated into annual pension costs of $31M, $35M and $28M, and for the distribution business this translated into annual pension costs of $36M, $39M and $38M, for 2023, 2024 and 2025.

Management prudently monitors the health of the DB Plan to determine the optimal timing of filing actuarial valuations based on the prescribed requirements (at a minimum a Tri-

[1] Wind-up basis valuations assume the plan is terminated and wound up on a specified date with all members' benefits being settled through either a purchase of annuities or the transfer of commuted values and the interest rates tend to fluctuate on a monthly basis. The assumptions therefore reflect the estimated cost of annuities and the prescribed assumptions for commuted values. The value of all benefits, including future indexation of benefits, is included in a wind-up valuation.

[2] This valuation also showed that the DB Plan had a surplus of $2,551M on a going-concern basis, however, as explained in section 2.3 below, whether or not there is a surplus on a going-concern basis is not relevant to the question of whether a contribution is required in a given year by Hydro One.

Annual valuation). Management filed annual valuations for each of the years ended December 31, 2021, 2022, 2023 and 2024 as it resulted in lower contributions than what would otherwise be required for the year, and chose not to file valuations for the years ended 2019 and 2020 as it would have resulted in increased contributions. Actual contribution requirements in 2028, 2029 and 2030 (period covered by the next required valuation) and any future years during the test period beyond 2030 may vary depending on market conditions, funding position of the pension fund and the level of base pensionable earnings and the resulting required contribution rates used to compute monthly contributions. The difference between the forecast and actual OM&A component of pension costs is tracked in a variance account (see Exhibit G-01-01, sections 7.16 and 9.20).

2.3 DB Plan Cost Recovery

Hydro One Inc. recognizes pension expense on a cash basis. Hydro One Inc. considers this method to be more beneficial to the customers of Hydro One Networks Inc. than the accrual basis because it generally results in lower yearly costs recovered through rates and less volatile forecasting of the cost, and it is thus more consistent with actual expenses for the applicable years. Additionally, the cash basis reflects the statutory amounts that Hydro One has to contribute to the DB Plan.

If Hydro One Inc. were to switch to the accrual basis, Hydro One Networks would be required to return the current pension benefit regulatory liability[3] over a 15 year period (which is the estimated average remaining service life of active employees). The pension benefit regulatory liability balance as at December 31, 2025 of $594M, which represents the cumulative life to date difference between the cash basis and the accrual basis of the DB Plan, is a direct offset of the pension asset as assessed by the actuaries.

Using a cash basis approach for cost recovery remains appropriate even if the DB plan is in a surplus position for accounting purposes. An accounting surplus does not determine

[3] Pension Benefit Regulatory Liability refers to a regulatory liability that Hydro One Inc. recognizes on the balance sheet on the basis of the OEB's approval of pension costs on a cash basis.

whether Hydro One Inc. may stop making contributions to the plan. That issue is governed by the applicable legislative funding requirements. Consistent with the EB-2019-0082 proceeding, with respect to the Transmission-related pension costs, Hydro One Networks explained that effective May 1, 2018, the Pension Benefits Act (PBA) and regulations provide that an employer like Hydro One may only take a contribution holiday in a year if an actuary certifies that a defined benefit plan has a funded ratio of at least 105% calculated on a wind-up basis. Under the December 31, 2018 valuation report, which was operative until December 31, 2021, Hydro One's DB Plan was 73% funded on a wind-up basis. As such, the OEB in EB-2019-0082 allowed the recovery of Hydro One's Transmission-related pension costs consistent with historical practice.

> The OEB finds that the pension and OPEB amounts requested by Hydro One for 2020 are supported by sufficient evidence and will allow the recovery of these amounts.[4]

Under the December 31, 2024 valuation report which is operative until December 31, 2027, Hydro One's DB Plan is 95% funded on a wind-up basis. A new valuation report for the DB Plan as at December 31, 2027, will be effective for the years 2028 to 2030, and thus will be in effect at the start of the test period on January 1, 2028. It is unlikely that the wind-up funded position of the DB Plan will improve so as to meet the 105% threshold at any time during the test period. Therefore, assuming the DB Plan remains less than 105% funded on a wind-up basis, Hydro One will not be able to take a contribution holiday and pension contributions will continue to be required over the 2028 to 2032 period. In these circumstances, recovery on a cash basis remains appropriate notwithstanding any accounting surplus position, because it reflects the actual amounts Hydro One Inc. is required to contribute to fund the plan during the test period.

If Hydro One were required to recover pension costs on an accrual basis while the plan remains in surplus, it could result in amounts being recovered through rates that are higher than the actual cash contributions required in the test period. By contrast, the cash basis

[4] EB-2019-0082, Decision and Order, April 23, 2020, p. 145

directly matches recovery to actual cash outflows and is therefore the more transparent and equitable approach.

Furthermore, the OEB has consistently allowed cash payments related to pension obligations to be recovered through rates in numerous prior Hydro One Networks Transmission and Distribution proceedings.[5] In the Transmission Revenue Requirement for 2020 to 2022 (EB-2019-0082) the OEB reaffirmed its approval of the cash basis, and this was not changed in the 2023 to 2027 Custom IR application (EB-2021-0110).

> Hydro One's use of the cash method for pensions and the accrual method for OPEBs for cost recovery is a continuation of the approach approved in Hydro One's last transmission proceeding, and is consistent with the approach approved for Hydro One's distribution business. The OEB's policy on pensions noted that for stability and predictability, maintaining a consistent method used to determine recovery over time may be one reason for not adopting the accrual method for rate setting.[6]

Tables 1a and 1b present analysis of the cash vs. accrual basis for pension costs for Transmission and Distribution for the DB Plan over the 2028 to 2032 test period.

Table 1a - Transmission Cash vs Accrual Basis Pension Costs ($M)

	2028		2029		2030		2031		2032	
Pension Costs	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**
OM&A	5	(5)	5	(5)	5	(5)	5	(6)	6	(8)
Capital	39	(35)	40	(38)	40	(42)	40	(44)	37	(45)
Return of Reg Liability(1)		(22)		(22)		(22)		(22)		(22)
Total	**44**	**(62)**	**45**	**(65)**	**45**	**(70)**	**45**	**(72)**	**43**	**(74)**

(1) Represents return of the $323M Pension Regulatory Liability at Dec. 31, 2025, with an assumption that 53% of the Pension Regulatory Liability is attributable to Hydro One Transmission and is recovered over a period of 15 years to 2040.

[5] RP-1998-0001; RP 2005-0020/EB-2005-0378; EB-2006-0501; EB-2008-0272: EB-2010-0002; EB-2012-0031; EB-2013-0416; EB-2014-0140; EB-2016-0160; EB-2017-0049; EB-2019-0082.
[6] EB-2019-0082, Decision and Order, April 23, 2020, p. 145

Table 1b - Distribution Cash vs Accrual Basis Pension Costs ($M)

	2028		2029		2030		2031		2032	
Pension Costs	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**	**Cash**	**Accrual**
OM&A	13	(12)	14	(13)	13	(14)	14	(16)	17	(21)
Capital	21	(18)	24	(23)	28	(30)	32	(35)	35	(43)
Return of Reg Liability (1)		(19)		(19)		(19)		(19)		(19)
Total	**34**	**(50)**	**38**	**(55)**	**42**	**(63)**	**46**	**(70)**	**52**	**(82)**

(1) Represents return of the $287M Pension Regulatory Liability at Dec. 31, 2025, with an assumption that 47% of the Pension Regulatory Liability is attributable to Hydro One Distribution and is recovered over a period of 15 years to 2040.

Hydro One Networks' pension cost is calculated by applying the contribution rate on base pensionable earnings of its employees that participate in the DB Plan.[7] The pension costs that Hydro One Networks proposes to recover through rates for the DB Plan, for Transmission and Distribution for 2028 to 2032, are provided in Table 2 below. The DB pension contributions are based on projected employer contributions as provided by Willis Towers Watson (WTW); the supporting document is provided as Attachment 2 to this Exhibit.

Table 2 - 2028-2032 Forecast DB Pension Costs ($M)[8]

2028 – Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	5	13
Capital	$M	39	21
Total	**$M**	**44**	**34**

[7] In years when minimum special payments or solvency payments are required under the Tri-Annual Valuation in effect, these are allocated in proportion to Hydro One Networks pension cost to the total pension cost of Hydro One Inc.

[8] The DB Plan valuation/projection that Hydro One undertakes includes Hydro One Limited and all of its regulated and non-regulated affiliates. The tables provided only present Transmission and Distribution.

2029 – Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	5	14
Capital	$M	40	24
Total	**$M**	**45**	**38**

2030 – Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	5	13
Capital	$M	40	28
Total	**$M**	**45**	**42**

2031 – Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	5	14
Capital	$M	40	32
Total	**$M**	**45**	**46**

2032 – Forecast			
DB Pension Costs		**Transmission**	**Distribution**
OM&A	$M	6	17
Capital	$M	37	35
Total	**$M**	**43**	**52**

2.4 DB Plan Performance

As noted above, Hydro One Inc. is the DB Plan sponsor and administers the pension assets and obligations of the DB Plan, in which Hydro One Networks is a participant. As at December 31, 2025, the DB Plan had a reported net asset value of $9,571M as per the audited financial statements and about 15,210 members. Approximately 45% of the DB Plan's members are active. The remaining DB Plan members are inactive, either retired, surviving spouses or beneficiaries of retirees, former employees eligible for a deferred pension, or members on long-term disability.

The going concern and solvency funded statuses are the primary ways that Hydro One can assess the Plan's success at providing benefit security to Plan members and contribution funding stability to Hydro One. Funding ratios greater than 100% indicate that the Plan holds more than a sufficient amount of assets to meet the long-term obligations of the Plan. The Plan ended 2024 with a going concern funded ratio of 137% (2023: 135%) and a solvency funded ratio of 134% (2023: 129%). Notwithstanding the going concern and solvency funded ratios, Hydro One would continue to be required to make contributions as that determination is based on the funded ratio on a wind-up basis, as discussed above.

3.0 DEFINED CONTRIBUTION PLAN

As indicated above, effective January 1, 2016, Hydro One introduced a DC Plan. The DC Plan covers Hydro One Limited and its subsidiaries. The DC Plan is registered with the FSRA and is a Registered Pension Trust as defined by the *Income Tax Act* (Canada) and as such is exempt from income taxes. The DC Plan is available for all new full-time and part-time MCP employees, who meet the eligibility requirements to join a pension plan on or after October 1, 2015 and who are not eligible to participate in the DB Plan. Members are able to join the DC Plan on the later of January 1, 2016 or the date they are made probationary or regular employees.

The DC Plan allows eligible employees to contribute up to 6% of their pensionable earnings with a 100% match of contributions by Hydro One. The value of the DC plan is determined by the sum of employer and employee contributions, plus investment earnings. Employee and employer contributions are invested by the DC Plan members among a range of investment options available through Sun Life, the DC Plan's record keeper. As at December 31, 2025, the DC Plan's assets were approximately $56M.

Pension benefits are paid upon termination or retirement and may be taken in the form of a life annuity from an insurer for those members who have achieved 55 years of age or a lump sum transfer equivalent to the accumulated value of the member's account.

Death benefits are available for the spouse or beneficiary(ies) on the death of an active member, and may be taken in the form of a life annuity from an insurer or a lump sum payment equivalent to the accumulated value of the member's account.

The forecast DC pension contributions in Table 3 below are based on projected employer contributions provided by WTW; the supporting document is provided as Attachment 2 to this exhibit.

Table 3 - 2028-2032 Forecast DC Pension Costs ($M)

2028 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.4	1.1
Capital	$M	3.2	1.7
Total	**$M**	**3.6**	**2.8**

2029 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.4	1.1
Capital	$M	3.3	2.0
Total	**$M**	**3.8**	**3.2**

2030 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.4	1.1
Capital	$M	3.4	2.4
Total	**$M**	**3.8**	**3.5**

2031 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.5	1.2
Capital	$M	3.4	2.8
Total	**$M**	**3.9**	**4.0**

2032 - Forecast			
DC Pension Costs		**Transmission**	**Distribution**
OM&A	$M	0.6	1.5
Capital	$M	3.3	3.1
Total	**$M**	**3.8**	**4.6**

4.0 OTHER POST-EMPLOYMENT BENEFIT (OPEB) COSTS

OPEBs cover Hydro One Limited and its subsidiaries including Hydro One Inc. These benefits cover eligible represented employees of the PWU and SUP, as well as MCP employees, pensioners who were previously employees, and pensioners who are beneficiaries or surviving spouses of employees or pensioners.

Consistent with past approvals, Hydro One uses the accrual method of accounting for OPEBs. OPEB benefit costs for the year are determined by the actuaries. Components of the cost include the accrual of current employee service cost for that year towards a liability for their retirement years and non-service costs, which include loss/gain amortization and interest adjustments. Paid benefit amounts are for retirees, drawn against the liability that was incurred by the company during their years of service.

Tables 4a and 4b summarize historical and forecast OPEB costs included in rates for each of the Transmission and Distribution businesses.

Table 4a - Transmission OPEB Costs Included in Rates ($M)

OPEBs	Pre 2023	2023	2024	2025	2026	2027	2028	Total
Amounts included in Transmission rates:								
OM&A	561	31	32	33	34	36	53	780
Capital (Note 1)	419	25	26	27	28	30	36	59
Deferral Account	41							41
Sub-total	**1,021**	**56**	**58**	**60**	**62**	**66**	**89**	**1,412**
Paid benefit amounts	351	31	33	32	38	51	46	582
Net excess amount included in rates greater than amounts actually paid	670	25	25	28	24	15	43	830

Note 1 – The capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess amount in each year noted does not represent the excess recovery in that year.

Table 4b - Distribution OPEB Costs Included in Rates ($M)

OPEBs	Pre 2023	2023	2024	2025	2026	2027	2028	Total
Amounts included in Distribution rates:								
OM&A	666	45	46	47	49	50	50	953
Capital (Note 1)	467	29	31	32	34	34	19	646
Deferral Account	74							74
Sub-total	**1,206**	**74**	**77**	**79**	**83**	**84**	**69**	**1,672**
Paid benefit amounts	533	35	38	41	37	28	35	747
Net excess amount included in rates greater than amounts actually paid	673	39	39	38	46	56	34	925

Note 1 – The capital component of OPEB costs is recovered over the useful life of the assets to which it is capitalized and not in the years noted. Therefore, the Net Excess amount in each year noted does not represent the excess recovery in that year

Under US GAAP, the non-service cost component of OPEBs can no longer be capitalized unless the regulator allows for the continued capitalization.[9] In the EB-2019-0082 Decision, the OEB concluded that the non-service cost component of Hydro One's OPEB costs shall

[9] In the case of the Federal Energy Regulatory Commission (FERC), it is allowing FERC-regulated utilities, which are subject to USGAAP and the changes in ASU 2017-07, to continue to capitalize both the service and non-service cost components of pensions and OPEBs.

be recognized as OM&A for both its transmission and distribution businesses. As such, Hydro One has not been tracking any amounts in the OPEB Cost Deferral Account for Transmission beyond 2019 and has stopped tracking these amounts for Distribution starting in 2023 (presented as Deferral Account in Table 4a and 4b above). Please refer to Exhibit G-01-01, sections 7.4 and 9.8, for additional details.

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September 23, 2025

Canada Revenue Agency
Registered Plans Directorate
Information Holdings Operation Section — Pensions
2215 Gladwin Cres
Ottawa, Ontario,
K1B 4K9

Subject: Hydro One Inc.
Hydro One Pension Plan — Registration No. 1059104

Actuarial Valuation as at December 31, 2024

For the above-mentioned plan, we have enclosed an actuarial valuation as at December 31, 2024 and the corresponding Actuarial Information Summary.

These items have also been filed with the Financial Services Regulatory Authority of Ontario.

Please contact me if you have any questions.

Regards,

Doris Gonsalves

Enclosures

Copy: Joanna Talbot, Carolyn Tsen, Kevin Eng – Hydro One
Suzanne Jacques – WTW

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HYDRO ONE INC.

Hydro One Pension Plan

Actuarial Valuation as at December 31, 2024

August 2025

Registration Number: 1059104

This document is being filed with the Pension Authorities as required by statute. Therefore, pursuant to subsection 20(1)(b) of the *Access to Information Act (Canada)*, or a corresponding provision under any comparable federal or provincial legislation, a government institution shall not disclose this document to any party as a result of a request under the *Access to Information Act (Canada)* or other applicable legislation.

DISCLAIMERS

This document is an actuarial valuation report of a pension plan. It is technical in nature and the reader should seek expert advice to fully understand it. The actuarial results presented here are based on numerous economic and demographic assumptions as to future events. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future actuarial valuations.

This report is based on the terms of engagement listed in Appendix A.

This report is based on the premise that all the plan's assets, including any letters of credit, are available to meet the plan's liabilities included in this actuarial valuation.

This report is based on the premise that the plan remains a going concern. This report does not address the disposition of any surplus assets remaining in the event of plan windup. If an applicable pension regulator or other entity with jurisdiction directs otherwise, certain financial measures contained in this report, including contribution requirements, may be affected.

The results presented in this report have been developed using a particular set of actuarial assumptions. Other results could have been developed by selecting different actuarial assumptions. The results presented in this report are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events.

Future contribution levels may change as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which have been anticipated at this time.

The results were developed with various data as at the date of the actuarial valuation that were provided to us: plan membership data, plan assets data, plan provisions and statement of investment policy. Towers Watson Canada Inc. (“WTW”) has relied on these data after verifying them and assessing their reasonableness. However, WTW has not independently audited these data.

The information contained in this report was prepared for Hydro One Inc., for its internal use and for filing with the Pension Authorities, in connection with the actuarial valuation of the plan prepared by WTW. This report is not intended, nor necessarily suitable, for other parties or for other purposes. Furthermore, some results in this report are based on assumptions mandated by legislation. These results may not be appropriate for purposes other than those for which they were prepared. WTW is available to provide additional information with respect to this report to the above-mentioned intended users upon request.

The numbers in this report are not rounded. The fact that numbers are not rounded does not imply a greater level of precision than if the numbers had been rounded.

Definitions

CIA means the Canadian Institute of Actuaries.

Pension Authorities means the Financial Services Regulatory Authority of Ontario and the Canada Revenue Agency ("CRA").

Pension Legislation means the *Pension Benefits Act (Ontario)* and Regulation thereto and the *Income Tax Act (Canada)* and Regulations thereto ("ITA").

The terminology used in this report is intended to convey the actuarial valuation results in a clear and straightforward manner, and assumes a common understanding of certain terms that are broadly applicable to pension plans in Canada. The terminology used in this report may differ from the corresponding terminology defined in Pension Legislation.

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Introduction

Purpose

This report with respect to the Hydro One Pension Plan has been prepared for Hydro One Inc., the plan administrator, and presents the results of the actuarial valuation of the plan as at December 31, 2024.

The principal purposes of the report are:

- to present information on the financial position of the plan on going concern, solvency and hypothetical windup bases; and
- to provide the basis for employer contributions.

Significant Events since Previous Actuarial Valuation (December 31, 2023)

On April 11, 2024, the CIA released a research paper on mortality improvements (Mortality Improvements Research). For the purpose of this report, the Mortality Improvements Research has been reflected (see Rationale for Assumptions in Appendix C for further details).

Effective March 31, 2025, certain plan provision changes previously negotiated between Hydro One and the Power Workers Union and Society of United Professionals, and implemented for Management employees, will take effect. The impact of these changes is reflected in the normal cost rule effective March 31, 2025. Appendix F contains the details of the plan provision changes.

There have been no other changes to the plan provisions, the legislation or actuarial standards having an impact on the actuarial valuation results.

Changes to the going concern basis are described in Appendix C. Changes to the solvency and hypothetical windup bases are described in Appendix D.

Subsequent Events

We completed this actuarial valuation on June 24, 2025.

To the best of our knowledge and on the basis of our discussions with Hydro One Inc., no other events which would have a material financial effect on the actuarial valuation occurred between the date of the actuarial valuation and the date this valuation was completed.

Next Actuarial Valuation

The next actuarial valuation of the plan must be performed with an effective date not later than December 31, 2027.

Section 1: Going Concern Financial Position

1.1 Statement of Financial Position

	December 31, 2024	December 31, 2023
Going Concern Value of Assets	$ 9,342,673,000	$ 9,093,232,000
Actuarial Liability		
Active, disabled and suspended members	$ 1,866,018,971	$ 1,786,072,924
Retired members and beneficiaries	4,876,031,769	4,886,008,311
Terminated vested members	49,868,598	50,085,785
Total actuarial liability	$ 6,791,919,338	$ 6,722,167,020
Actuarial Surplus (Unfunded Actuarial Liability)	$ 2,550,753,662	$ 2,371,064,980
Prior year credit balance	(20,700,000)	(16,200,000)
Actuarial Surplus (Unfunded Actuarial Liability) After Prior Year Credit Balance	$ 2,530,053,662	$ 2,354,864,980
Funded Ratio[1]	137%	135%
Provision for adverse deviations (PfAD)	$ 395,588,021	$ 404,341,100
Actuarial Surplus (Unfunded Actuarial Liability) After PfAD	$ 2,134,465,641	$ 1,950,523,880
Excess Surplus[2]	$ 0	$ 0

Notes:

[1] After reflecting prior year credit balance.

[2] Considered to be nil if there is a hypothetical windup or solvency deficit.

Comments:

- The prior year credit balance is employer contributions made prior to the date of the actuarial valuation that are in excess of the minimum required and are set aside as a reserve for application towards future contribution requirements.
- The plan provides for indexation (escalated adjustments, as defined in Pension Legislation). The actuarial liability as at December 31, 2024 shown above includes $1,140,661,895 in respect of indexation.The actuarial liability in respect of indexation has not been included in determining the PfAD.

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1.2 Reconciliation of Financial Position and Provision for Adverse Deviations

1.2.1 Reconciliation of Financial Position

Actuarial surplus (unfunded actuarial liability) as at December 31, 2023		$ 2,371,064,980
PfAD contributions		8,070,000
Additional Employer contributions		4,500,000
Expected interest on:		
• Actuarial surplus (unfunded actuarial liability)	$ 154,119,224	
• PfAD contributions	258,146	
• Additional Employer contributions	143,948	154,521,318
Plan experience:		
• Investment gains (losses)	$ (65,070,964)	
• Salary gains (losses)	1,404,560	
• YMPE gains (losses)	1,230,902	
• Cost-of-living adjustment gains (losses)	22,853,751	
• Retirement gains (losses)	3,600,587	
• Withdrawal gains (losses)	(5,367,540)	
• Mortality gains (losses)	7,049,598	
• Miscellaneous liability gains (losses)	4,093,739	(30,205,367)
Change in actuarial basis:		
• Inflation for post-retirement pension increases	11,396,805	
• Discount rate	247,426,247	
• Mortality improvement scale	(208,683,302)	
• Retirement assumption	(14,715,566)	
• Spousal assumption	7,378,547	42,802,731
Actuarial surplus (unfunded actuarial liability) as at December 31, 2024		$ 2,550,753,662

1.2.2 Reconciliation of Provision for Adverse Deviations

Provision for adverse deviations as at December 31, 2023			$	404,341,100
Expected interest on the provision for adverse deviations				26,282,172
Change in provision for adverse deviations:				
• Increase (decrease) due to change in actuarial liability other than interest	$	(18,081,479)		
• Increase (decrease) due to change in PfAD level		(16,953,772)		(35,035,251)
Provision for adverse deviations as at December 31, 2024			$	395,588,021

1.3 Contributions (Ensuing Year)

		December 31, 2024		December 31, 2023
Employer Normal Actuarial Cost				
Normal actuarial cost in respect of benefit accruals	$	136,608,996	$	133,716,464
Provision for adverse deviations (PfAD)		7,697,917		7,867,609
Estimated member contributions		(78,337,143)		(72,042,746)
Employer normal actuarial cost	$	65,969,770	$	69,541,327
Estimated payroll [1]	$	854,403,657	$	780,072,718
Employer normal actuarial cost as % of payroll		7.7%[2]		8.9%

Note:

1 Reflects adjustments for members retiring or terminating during the year.

2 Reflects future service changes to the final average earnings definition and to the unreduced retirement eligibility applicable to certain members, as described in Appendix F. Employer normal cost as % of payroll for 2025 is: 8.0% from January 1, 2025 to March 31, 2025, 7.6% thereafter.

Comment:

- The normal actuarial cost as at December 31, 2024 shown above includes $26,638,753 in respect of indexation. The normal actuarial cost in respect of indexation has not been included in determining the PfAD.

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Reconciliation of Employer Normal Actuarial Contribution Rule

Employer normal actuarial cost as a % of payroll at December 31, 2023	8.9%
• Changes in membership profile	(0.2)%
• Changes in actuarial basis	(0.7)%
• Change in the PfAD level	0.0%
Employer normal actuarial cost as a % of payroll at December 31, 2024	8.0%
Impact of March 31, 2025 Plan changes[1]	(0.4)%
Employer normal actuarial cost as a % of payroll at April 1, 2025	7.6%

Note:

[1] Reflects future service changes to the final average earnings definition and to the unreduced retirement eligibility applicable to certain members, as described in Appendix F.

1.4 Reconciliation of Prior Year Credit Balance (Cash Basis)

Prior year credit balance as at December 31, 2023		$ 16,200,000
Actual employer contributions:		
• Normal actuarial cost and PfAD contributions	$ 70,922,000	
• Other contributions	4,500,000	75,422,000
Minimum employer contributions required:		
• Normal actuarial cost and PfAD contributions	$ (70,922,000)	
• Other contributions	0	(70,922,000)
Application against unfunded actuarial liability		0
Prior year credit balance as at December 31, 2024		$ 20,700,000

Section 2: Solvency and Hypothetical Windup Financial Position

2.1 Statement of Solvency and Hypothetical Windup Financial Position

	December 31, 2024	December 31, 2023
Solvency Value of Assets		
Market value of assets	$ 9,331,959,000	$ 8,782,855,000
Provision for plan windup expenses	(8,000,000)	(8,000,000)
Total solvency value of assets	$ 9,323,959,000	$ 8,774,855,000
Solvency Liability		
Active, disabled and suspended members	$ 2,088,582,558	$ 1,902,318,486
Retired members and beneficiaries	4,811,578,466	4,850,631,670
Terminated vested members	53,123,685	51,498,005
Total solvency liability	$ 6,953,284,709	$ 6,804,448,161
Solvency Surplus (Unfunded Solvency Liability)	$ 2,370,674,291	$ 1,970,406,839
Prior year credit balance	$ 20,700,000	$ 16,200,000
Solvency Ratio	134%	129%
Value of excluded benefits	$ 2,799,876,100	$ 2,715,105,535
Total hypothetical windup liability	$ 9,753,160,809	$ 9,519,553,696
Hypothetical Windup Surplus (Unfunded Hypothetical Windup Liability)	$ (429,201,809)	$ (744,698,696)
Lesser of estimated employer contributions for the period until the next actuarial valuation and the prior year credit balance	$ 20,700,000	$ 16,200,000
Transfer Ratio	95%	92%

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	December 31, 2024	December 31, 2023
PBGF Information		
Ontario PBGF liability	$ 6,953,284,709	$ 6,804,448,161
Ontario asset ratio	100%	100%
Ontario portion of the fund	$ 9,331,959,000	$ 8,782,855,000
PBGF assessment base	$ 0	$ 0
Ontario additional PBGF liability	$ 0	$ 0

Comments:

- The solvency valuation results presented in this report are determined under a scenario where, following a plan windup, the employer continues its operations.
- The hypothetical windup valuation results presented in this report are determined under the same scenario used for the solvency valuation.
- As the transfer ratio is less than 100%, transfer deficiencies must be paid over a maximum period of five years unless the cumulative transfer deficiencies are within the limits prescribed by Pension Legislation or the employer remits additional contributions in respect of the transfer deficiencies. Pursuant to Regulations 19(4) or 19(5) to Pension Legislation, approval of the Financial Services Regulatory Authority of Ontario Chief Executive Officer will be required to make commuted value transfers if there has been a significant decline in the transfer ratio after the date of the actuarial valuation.

2.2 Determination of the Statutory Solvency Excess (Deficiency)

In calculating the statutory solvency excess (deficiency), various adjustments may be made to the solvency financial position.

	December 31, 2024	December 31, 2023
Solvency surplus (unfunded solvency liability)	$ 2,370,674,291	$ 1,970,406,839
Adjustments to solvency position:		
• Present value of existing amortization payments	$ 0	$ 0
• Smoothing of asset value	10,714,000	310,377,000
• Adjustment to reflect reduced solvency deficiency [1]	1,138,346,559	1,149,283,933
• Averaging of liability discount rate [2]	(635,692,354)	(857,444,724)
• Prior year credit balance	(20,700,000)	(16,200,000)
• Total	$ 492,668,205	$ 586,016,209
Solvency excess (reduced solvency deficiency)	$ 2,863,342,496	$ 2,556,423,048

Notes:

[1] Reflects 15% of the solvency liabilities based on the discount rates after averaging.

[2] Reflects the difference between the solvency liabilities based on the discount rates before and after averaging.

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Section 3: Contributions

3.1 Estimated Minimum Employer Contribution (Ensuing Years)

Year		2025		2026		2027
Normal actuarial cost (excluding the PfAD)	$	136,608,996	$	137,106,615	$	139,467,210
PfAD		7,697,917		7,735,555		7,878,503
Estimated member contributions		(78,337,143)		(77,951,374)		(78,133,464)
Employer normal actuarial cost	$	65,969,770	$	66,890,796	$	69,212,249
Application of prior year credit balance [1]		0		0		0
Application of available actuarial surplus		0		0		0
Estimated minimum employer contribution	$	65,969,770	$	66,890,796	$	69,212,249

Note:

[1] As at the actuarial valuation date a $20,700,000 Prior Year Credit Balance exists, which may be applied to reduce Employer contributions in 2025, 2026 or 2027.

Comments:

- As there is no available actuarial surplus present in this actuarial valuation, the plan sponsor must remit contributions not less than the minimum required by Pension Legislation.
- The changes for future service, effective March 31, 2025, to the final average earnings definition and to the unreduced retirement eligibility applicable to certain members, as described in Appendix F, are reflected starting effective April 2025 in the above estimated minimum employer contributions.

3.2 Estimated Maximum Employer Contribution (Ensuing Year)

		December 31, 2024
Employer normal actuarial cost	$	65,969,770
Greater of the unfunded actuarial liability and the unfunded hypothetical windup liability		429,201,809
Estimated maximum employer contribution	$	495,171,579

Comment:

- In general terms, the employer may contribute its total normal actuarial cost plus the largest of the going concern and hypothetical windup deficits and accrued interest. This amount shall be reduced by any excess actuarial surplus and any contributions made since the date of the actuarial valuation. Pension Legislation may require that certain minimum contributions be nevertheless remitted.

3.3 Timing of Contributions

Employer normal cost and member contributions must be remitted monthly and within 30 days of the month to which they pertain.

Amortization payments must be remitted monthly before the end of the month to which they pertain (or replaced by an equivalent letter of credit), if applicable.

If an adjustment is required to contributions made since the date of the actuarial valuation, any amount due must be remitted with interest within 60 days from the date that this report is filed with the Pension Authorities.

Contributions that are remitted to the plan in the taxation year or within 120 days after the end of such taxation year are deductible in such taxation year provided they were made to fund benefits in respect of periods preceding the end of the taxation year.

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Section 4: Actuarial Opinions

In our opinion, for the purposes of the going concern, solvency and hypothetical windup valuations:

- the membership data on which the valuations are based are sufficient and reliable,
- the assumptions are appropriate, and
- the methods employed in the valuations are appropriate.

This report has been prepared, and our opinions have been given, in accordance with accepted actuarial practice in Canada. The valuations have been conducted in accordance with our understanding of the funding and solvency standards prescribed by Pension Legislation.

Towers Watson Canada Inc.

Davis Gonsalves

Davis Gonsalves
Fellow of the Canadian Institute of Actuaries

Suzanne Jacques

Suzanne Jacques
Fellow of the Canadian Institute of Actuaries

Toronto, Ontario
August 2025

Appendix A: Significant Terms of Engagement and Certificate of the Plan Administrator

A.1 Significant Terms of Engagement

For purposes of preparing this actuarial valuation report, the plan administrator has directed that:

- The actuarial valuation is to be prepared as at December 31, 2024.
- No margins for adverse deviations are to be used.
- For the purpose of determining the going concern discount rate, the investment policy dated August 13, 2024, which is the most up-to-date version, should be considered. The current investment policy does not provide for any changes to the target asset class distribution in the future.
- For purposes of determining the provision for adverse deviations level as at December 31, 2024, the target asset allocation should be that contained in the investment policy statement in effect at August 13, 2024.
- For purposes of determining the provision for adverse deviations level, the plan is to be considered open to new entrants.
- The going concern value of assets is to be determined using the averaging technique described in the Asset Valuation Method section in Appendix C.
- The going concern valuation should use the projected unit credit actuarial cost method.
- For purposes of determining the solvency liability of the plan, certain benefits are to be excluded without requiring an election from the employer.
- The solvency and hypothetical windup valuation results are to be determined under a scenario where the employer continues to operate and all expenses are paid from the pension fund.
- This report is to be prepared on the basis that the employer is entitled to apply the available actuarial surplus, if any, to meet its contribution requirements under the plan.
- For the purpose of estimating the effects of plausible adverse scenarios, the risk assessments shown in this report are to be performed on a going concern basis, and the risks assessed are appropriate for the plan.

Should these directions from the plan administrator be amended or withdrawn, WTW reserves the right to amend or withdraw this report.

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A.2 Certificate of the Plan Administrator

I hereby certify that to the best of my knowledge and belief:

- the significant terms of engagement contained in Appendix A of this report are accurate and reflect the plan administrator's judgement of the plan provisions and/or an appropriate basis for the actuarial valuation of the plan;
- the information on plan assets, including the information on the investment policy and intended changes to the asset mix distribution after the date of the actuarial valuation, if any, forwarded to Towers Watson Canada Inc. and summarized in Appendix B of this report is complete and accurate;
- the data forwarded to Towers Watson Canada Inc. and summarized in Appendix E of this report are a complete and accurate description of all persons who are members of the plan, including beneficiaries who are in receipt of a retirement income, in respect of service up to the date of the actuarial valuation;
- the summary of plan provisions contained in Appendix F of this report is accurate;
- for purposes of determining the provision for adverse deviations level, the fixed income allocation for each asset class shown in Appendix G is appropriate; and
- there have been no events which occurred between the date of the actuarial valuation and the date this actuarial valuation was completed that may have a material financial effect on the valuation.

Signature	September 22, 2025 Date
Carolyn Tsen Name	Director, Pension Fund Title

Appendix B: Assets

B.1 Statement of Market Value

	December 31, 2024	December 31, 2023
Total invested assets:	9,331,959,000	8,782,855,000
Net outstanding amounts:		
• Contributions receivable		
– Employer normal cost	$ 0	$ 0
– Members contributions	0	0
– Amortization payments	0	0
– PfAD contributions	0	0
– Others	0	0
• Benefits payable	0	0
• Expenses and other payables	0	0
• Total net outstanding amounts	$ 0	$ 0
Total assets	$ 9,331,959,000	$ 8,782,855,000

Comment:

- The data relating to the invested assets are based on the financial statements issued by KPMG. The data relating to net outstanding amounts were furnished by Hydro One Inc.

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B.2 Asset Class Distribution

The following table shows the target asset allocation stipulated by the plan's investment policy in respect of major asset classes and the actual asset allocation as at December 31, 2024.

	Target asset allocation	Actual asset allocation as at December 31, 2024
Global equities	30.0%	31.3%
Private equities	10.0%	10.4%
Real estate and infrastructure	25.0%	21.9%
Bonds and debentures	28.0%	30.4%
Private debt	5.0%	4.0%
Cash and short-term investments	2.0%	2.0%
Total	100.0%	100.0%

B.3 Reconciliation of Invested Assets (Market Value)

Assets as at December 31, 2023			$	8,782,855,000
Receipts:				
• Contributions:				
– Employer normal actuarial cost	$	75,422,000		
– Employer amortization payments		0		
– Member required contributions		74,306,000		
– Past service contributions		8,639,000		
– PfAD contributions related to the provision for non-investment expenses		0	$	158,367,000
• Investment return, net of investment expenses				838,615,000
• Total receipts			$	996,982,000
Disbursements:				
• Benefit payments:				
– Pension payments	$	(407,711,000)		
– Lump sum settlements		(18,632,000)		
– Other benefit payments		0	$	(426,343,000)
• Non-investment expenses				(21,535,000)
• Total disbursements			$	(447,878,000)
Assets as at December 31, 2024			$	9,331,959,000

Comments:

- This reconciliation is based on the financial statements issued by KPMG and Hydro One.
- The rate of return earned on the market value of assets, net of all expenses, from December 31, 2023 to December 31, 2024 is approximately 9.5%.

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B.4 Development of the Going Concern Value of Assets

	Adjusted Market Value Beginning from:				
	December 31, 2020	**December 31, 2021**	**December 31, 2022**	**December 31, 2023**	**December 31, 2024**
Adjusted market value as at December 31, 2020	$ 8,143,965,000				
Net cash flow for 2021	(268,238,000)				
Assumed investment return	480,708,000				
Adjusted market value as at December 31, 2021	$ 8,356,435,000	$ 8,644,382,000			
Net cash flow for 2022	(243,847,000)	(243,847,000)			
Assumed investment return	477,701,000	494,402,000			
Adjusted market value as at December 31, 2022	$ 8,590,289,000	$ 8,894,937,000	$ 7,902,567,000		
Net cash flow for 2023	(283,828,000)	(283,828,000)	(283,828,000)		
Inergi LP Plan transfer	378,523,000	378,523,000	378,523,000		
Assumed investment return	569,585,000	589,388,000	524,884,000		
Adjusted market value as at December 31, 2023	$ 9,254,569,000	$ 9,579,020,000	$ 8,522,146,000	$ 8,782,855,000	
Net cash flow for 2024	(267,976,000)	(267,976,000)	(267,976,000)	(267,976,000)	
Assumed investment return	592,975,000	614,064,000	545,367,000	562,313,000	
Adjusted market value as at December 31, 2024	$ 9,579,568,000	$ 9,925,108,000	$ 8,799,537,000	$ 9,077,192,000	$ 9,331,959,000
Going Concern Value of Assets					
Average of the five adjusted market values as at December 31, 2024					$ 9,342,673,000
Net outstanding amounts					0
Going concern value of assets as at December 31, 2024					$ 9,342,673,000

Comment:

- The rate of return earned on the going concern value of assets, net of all expenses, from December 31, 2023 to December 31, 2024 is approximately 5.8%.

Appendix C: Actuarial Basis – Going Concern Valuation

C.1 Methods

Asset Valuation Method

The going concern value of assets was calculated as the average of the market value of invested assets at the valuation date and the four previous years' adjusted market values. The market values at December 31 of each of the four preceding years were accumulated to the valuation date with net cash flow (i.e., contributions less benefit payments) and assumed investment return. Net cash flow was assumed to occur uniformly throughout each year, with the exception of April 3, 2023 Inergi transfer for which the actual transfer date was reflected. Assumed investment return for a year was calculated assuming that each year, the assets earned interest at the going concern discount rate in effect for that year. Finally, this 5-year average of adjusted market values was then adjusted for net outstanding amounts.

The objective of the asset valuation method is to produce a smoother pattern of going-concern surplus (deficit) and hence a smoother pattern of contributions, consistent with the long-term nature of a going concern valuation.

Such smoothing is achieved by use of an averaging process which systematically recognizes investment returns different from expectations over a 5-year period, with 20% recognized at the valuation date and the remainder at a rate of 20% per year. This method will be expected to average periods of outperformance with periods of underperformance.

The expected return of the going concern discount rate has been selected to equal the expected return on the assets over long periods of time.

Actuarial Cost Method

The actuarial liability and the normal actuarial cost were calculated using the projected unit credit cost method (benefit accrual).

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C.2 Actuarial Assumptions

	December 31, 2024	December 31, 2023
Economic Assumptions (per annum)		
Liability discount rate	6.80%	6.50%
Rate of inflation	2.00%	Same
Inflation for post-retirement pension increases	2.00%	3.50% at January 1, 2025, 2.25% at January 1, 2026 & 2.00% thereafter
Rate of salary increase	See Tables 1 & 3	See Tables 1 & 2
Escalation of YMPE under Canada Pension Plan [1]	3.00%	Same
Escalation of ITA maximum pension limit [2]	3.00%	Same
Interest on members' contributions	2.00%	Same
Demographic Assumptions		
Mortality	90% of 2014 Private Sector Canadian Pensioners' Mortality Table (CPM2014Priv), projected generationally using Scale MI-2024	90% of 2014 Private Sector Canadian Pensioners' Mortality Table (CPM2014Priv), projected generationally using Scale CPM-B
Retirement from active membership	Age and service related rates (Table 5)	Age and service related rates (Table 4)
Pension commencement after termination of employment	Age 65	Same
Withdrawal	Age-related rates (Table 6)	Same
Disability incidence/recovery	Age-related rates (Table 7)	Same
Other		
Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form	80%	85%
Years male spouse older than female spouse	2	Same
Provision for non-investment expenses	None; return on plan assets is net of all expenses	Same

Notes:

[1] The YMPE of $71,300 for 2025 is the starting value for the YMPE projection as at the current actuarial valuation and is indexed starting in 2026.

[2] The ITA maximum pension limit of $3,756.67 per year of service in 2025 is the starting value for maximum pension limit projection as at the current actuarial valuation and is indexed starting in 2026.

Table 1 — Merit and Promotion Scale

Age	First 4 Years of Employment	Subsequent Years
Under 25	7.5%	2.0%
25 – 29	5.5%	2.0%
30 – 34	3.5%	2.0%
35 – 39	3.5%	1.5%
40 – 44	3.5%	1.5%
45 – 49	2.0%	1.0%
50 - 54	2.0%	1.0%
55 – 59	1.0%	0.5%
60 & over	1.0%	0.0%

Table 2 — Fixed Increases at December 31, 2023

Group	2024	2025	2026-2027	2028 onward
PWU	4.00%	3.50%	2.00%	2.50%
Society	4.00%	3.50%	2.00%	2.50%
Management	2.50%	2.00%	2.00%	2.50%

Table 3 — Fixed Increases at December 31, 2024

Group	2025[1]	2026-2027	2028 onward
PWU	3.50%	2.00%	2.50%
Society	3.50%	2.00%	2.50%
Management	3.50%	2.00%	2.50%

[1] Reflected in salary information shown in Appendix E.

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Table 4 — Retirement Rates at December 31, 2023

	Eligible for Unreduced Retirement		
Age	**Based on points (82 or 85)**	**35 years of service and over**	**Not Eligible for Unreduced Retirement**
Under 55	13%	45%	0%
56 to 57	13%	45%	5%
58	13%	30%	5%
59	15%	30%	8%
60	15%	30%	8%
61	15%	20%	8%
62 to 64	25%	20%	8%
65	50%	50%	30%
66 to 69	25%	40%	20%
70 and over	100%	100%	100%

Table 5 — Retirement Rates at December 31, 2024

	Eligible for Unreduced Retirement		
Age	**Based on points (82 or 85)**	**35 years of service and over**	**Not Eligible for Unreduced Retirement**
Under 55	13%	25%	0%
55	13%	25%	2%
56 to 59	20%	25%	2%
60	25%	25%	2%
61 to 62	25%	10%	5%
63	15%	10%	5%
64	15%	30%	5%
65	45%	60%	35%
66 to 69	20%	20%	20%
70 and over	100%	100%	100%

Table 6 — Termination rates

Service (years)	Rates
Under 20	1.2%
20 and over	0%

Table 7 — Sample Disability Rates

Age	Male & Female
Under 30	0.10%
30 to 39	0.25%
40 to 49	0.45%
50 to 54	0.75%
55 to 59	0.85%
60 and above	1.60%

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C.4 Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the going concern valuation is summarized below.

The going concern assumptions do not include margins for adverse deviations as a separate provision for adverse deviations has been applied to the actuarial liability and normal actuarial cost.

Liability discount rate

The assumption is an estimate of the expected long-term return on plan assets adjusted as follows:

• Expected long-term return on plan assets before adjustments	6.94%
• Investment management fees	(0.06)%
• Adjustment for non-investment expenses paid by the plan	(0.08)%
• Rounding	0.00%
• Expected long-term return on plan assets after adjustments	6.80%

Actuarial valuation economic assumptions used for establishing the liability discount rate have been developed based on WTW's capital market model which simulates economic variables and asset class returns. For purposes of calculating the expected long-term returns for each asset class, it has been assumed that key economic variables (such as price inflation and bond yields) transition over time from initial conditions to long-term normative assumptions. Long-term normative assumptions are established based on a blend of historical capital market data and future expectations and do not change frequently. In current capital market conditions, the normative assumptions reflect the expectation that intermediate and long-term bond yields will increase over time.

Rate of inflation

Estimate of future rates of inflation considering economic and financial market conditions at the valuation date. Furthermore, the Bank of Canada targets an inflation rate between 1.0% and 3.0% (2.0% average).

The inflation rate used to determine the post-retirement pension increases are based on the long term expectations provided by the Bank of Canada.

Rate of salary increase

The fixed increase component of the salary scale (for 2028 onwards; shown in Table 3 above), and the Merit and Promotion scale was developed based on a review of plan experience for the years 2002 to 2016 and an assessment of future expectations.

The fixed increases (shown in Table 3 above) for 2025 to 2027 were provided by Hydro One.

At the previous actuarial valuation, the fixed increases (shown in Table 2 above) for 2024 to 2027 were used.

Escalation of YMPE under C/QPP and ITA limit

Indexed annually based on increases in the Industrial Aggregate Wage index for Canada, assumed to be a rate of inflation of 2.00% per annum, plus 1.00% per annum for the effect of real economic growth and productivity gains in the economy.

Mortality

Base mortality rates from the CPM2014Priv table, with a multiplier of 90% based on a review of the experience of the plan's actual mortality experience over the period 2016-2020, are considered reasonable for the actuarial valuation. Applying an improvement scale generationally provides allowance for improvements in mortality after 2014.

In April 2024, the CIA released the *Mortality Improvements Research* report, which included improvement rates for future mortality. In May 2024, the CIA Committee on Pension Plan Financial Reporting issued an Educational Note Supplement noting it believes that at the current time it may be appropriate to use any of the MI-2017 improvement scale, the CPM-B scale, or the proposed mortality projection scale published in the *Mortality Improvements Research* report (referenced here as MI-2024) for pension plan actuarial valuations, subject to consideration of relevant factors. For the current actuarial valuation, we prepared the results using the mortality improvement scale MI-2024 published in the *Mortality Improvements Research* report.

At the previous actuarial valuation, mortality improvement scale CPM-B was used.

Retirement from active membership

The rates of retirement were developed based on a review of plan experience for the years 2020 to 2024 and an assessment of future expectations. All members are assumed to commence their pension at retirement date.

Pension commencement after termination of employment

All terminated members are assumed to commence their pension at the age that produces the highest liability.

Withdrawal

The rates of withdrawal were developed based on a review of plan experience for the years 2020 to 2024 and an assessment of future expectations.

Percentage of involuntary terminations of employment

No allowance has been made for involuntary terminations of employment since assuming otherwise would not have a material impact on the actuarial valuation results.

Disability incidence/recovery

The rates of disability incidence/recovery were developed based on a review of plan experience for the years 2019 to 2023 and an assessment of future expcations.

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Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form

When provided, the actual data for the spouse and form of payment were used for retired members. For other members, the assumed percentage of members with a spouse were developed based on a review of plan experience for the years 2020 to 2024 and an assessment of future expectations.

Years male spouse older than female spouse

When provided, the actual data for the spouse were used for retired members. For other members, a review of plan data for the years 2020 to 2024, and an assessment of future expectations for members of the plan was used.

Provision for non-investment expenses

The liability discount rate is net of all expenses (with the exception of any fees associated with employing an active investment management strategy). The assumed level of expenses reflected in the liability discount rate is based on recent experience of the plan and an assessment of future expectations.

Appendix D: Actuarial Basis – Solvency and Hypothetical Windup Valuations

D.1 Methods

Asset Valuation Method

The market value of invested assets, adjusted for net outstanding amounts, has been used for the solvency and hypothetical windup valuations. The resulting value has been reduced by a provision for plan windup expenses.

The adjustment in respect of the smoothing of solvency assets for purposes of determining the statutory solvency deficiency was calculated as the difference between the going concern of assets used for the going concern valuation and the market value of assets.

Liability Calculation Method

The solvency and hypothetical windup liabilities for members were calculated using the traditional unit credit cost method.

Other Considerations

The solvency and hypothetical windup valuations have been prepared on a hypothetical basis. In the event of an actual plan windup, the plan assets may have to be allocated between various classes of plan members or beneficiaries as required by applicable Pension Legislation. Such potential allocation has not been performed as part of these solvency and hypothetical windup valuations.

D.2 Solvency Incremental Cost Actuarial Method

To calculate the Solvency Incremental Cost ("SIC"), we used the same method as for the solvency valuation.

No new entrants have been considered on the basis that such assumption would not have a material impact on the SIC. The projected population, benefits and members' contributions were adjusted with the going concern actuarial assumptions and the plan provisions.

We adjusted the expected settlement method at the end of the projection period to reflect demographic evolution of each plan member. Regardless of that change, we used the discount rate applicable to the settlement method at the valuation date for each member.

The liability discount rates (before averaging) are assumed to remain at their current level over the projection period.

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D.3 Actuarial Assumptions

	December 31, 2024	December 31, 2023
Economic Assumptions (per annum)		
Liability discount rate		
• Annuity purchase (non-indexed)	4.57%	4.40%
• Annuity purchase (fully-indexed)	1.51%	1.40%
• Annuity purchase (partially-indexed)[1]	2.28%	2.15%
• Commuted value transfer (non-indexed)	3.90% for 10 years, 4.50% thereafter	4.50% for 10 years, 4.50% thereafter
• Commuted value transfer (fully-indexed)	2.10% for 10 years, 2.60% thereafter	2.70% for 10 years, 2.80% thereafter
• Commuted value transfer (partially-indexed)	2.60% for 10 years, 3.10% thereafter	3.20% for 10 years, 3.20% thereafter
Liability discount rate (after averaging for solvency)		
• Annuity purchase	3.77%	3.43%
• Commuted value transfer	3.24% for 10 years, 3.96% thereafter	2.94% for 10 years, 3.56% thereafter
Discount rate for determining amortization payments	N/A	Same
Escalation of *Income Tax Act* (Canada) maximum pension limitation [2]	3.00%	Same
Demographic Assumptions		
Mortality		
• Annuity purchase	90% of 2014 Private Sector Canadian Pensioners' Mortality Table (CPM2014Priv), projected generationally using Scale CPM-B	Same
• Commuted value transfer	CPM2014 Canadian Pensioners' Mortality Table, projected generationally using Scale CPM-B	Same

	December 31, 2024	December 31, 2023
Retirement/pension commencement	Described in section D.4	Same
Other		
Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form	80%	85%
Years male spouse older than female spouse	2	Same
Percentage of members receiving settlement by commuted value transfer [3]	Retired members and beneficiaries: 0% Other members: • Not eligible for retirement: 60% • Eligible for retirement: 20%	Same
Provision for expenses		
• Solvency and Hypothetical windup	$8,000,000	Same

Notes:

[1] Applicable to New Society and New Management members only.

[2] The ITA maximum pension limit is $3,756.67 per year of service in 2025 and is indexed starting in 2026.

[3] The balance are assumed to receive settlement by annuity purchase.

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D.4 Rationale for Actuarial Assumptions

The rationale for the material actuarial assumptions used in the solvency and hypothetical windup valuations is summarized below.

The actuarial assumptions used in the solvency and hypothetical windup valuations do not include margins for adverse deviations.

Liability discount rate

Portion of the solvency and hypothetical windup liabilities expected to be settled by a group annuity purchase

Based on the CIA annuity purchase guidance applicable at the valuation date which corresponds to an approximation of the annuity purchase rate. The duration of the liabilities assumed to be settled through the purchase of non-indexed annuities, prior to reflecting any adjustments to the mortality table, is 10.1.

The discount rate has been adjusted by (0.15)% to be consistent with the adjustment made to the mortality table underlying the CIA annuity purchase guidance, as described below.

Portion of the solvency and hypothetical windup liabilities expected to be settled by commuted value transfer

Determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the date of the actuarial valuation.

Liability discount rate for solvency (after averaging)

The average discount rates for calculation of the statutory solvency deficiency are based on the following:

Benefits that are expected to be settled by a group annuity purchase, the average of the annualized approximate annuity purchase rates at December 31, 2024 and the four previous year-ends[1], determined as follows:

December 31, 2020	2.36%
December 31, 2021	2.76%
December 31, 2022	4.76%
December 31, 2023	4.40%
December 31, 2024	4.57%
Average	3.77%

Note :

[1] When applicable, the approximate annuity purchase interest rates prior to December 31, 2024 have been adjusted to reflect the change in the mortality table assumption applicable to the determination of liabilities settled by group annuity purchase.

Benefits that are expected to be settled by commuted value transfers, the average of the interest rates determined under the *Standards of Practice for Pension Commuted Values,* published by the Canadian Institute of Actuaries, at December 31, 2024 and the four previous year-ends, determined as follows:

	Rate for 10 years	Rate after 10 years
December 31, 2020	1.40%	2.90%
December 31, 2021	2.30%	3.40%
December 31, 2022	4.10%	4.50%
December 31, 2023	4.50%	4.50%
December 31, 2024	3.90%	4.50%
Average	3.24%	3.96%

Escalation of ITA maximum pension limit

See rationale for going concern assumptions in Appendix C.

Post-retirement pension increases

For the solvency valuation, as permitted under Pension Legislation, post-retirement pension increases are assumed to be nil. For the hypothetical windup valuation, the assumption has been determined by applying the post-retirement increase provisions specified in the plan to the inflation assumption.

Mortality

For the benefits that are expected to be settled by a group annuity purchase

Based on CIA annuity purchase guidance. This guidance indicates that an adjustment to regular annuity purchase assumptions would be expected where there is demonstrated sub- or super-standard mortality versus a typical group annuity purchase, or where an insurer might be expected to assume significantly shorter or longer-than-average pension plan longevity based on the above factors. In this regard, the mortality assumptions being used on a going concern basis suggests that the standard mortality rates be adjusted. For solvency and windup valuation purposes, base mortality rates from the CPM2014 Private table have been used, with a multiplier of 90%, projected generationally using improvement scale CPM-B. In order to reflect the plan-specific mortality, we recalibrate the CIA annuity purchase guidance to replace CPM2014 Combined (which we believe is more conservative than the mortality rates for a typical group annuity purchase) with CPM2014 Private (which we believe is more representative), as illustrated below, thereby lowering the discount rate.

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	Mortality Table	Discount Rate	Solvency Liability
Calculate preliminary solvency liability for benefits expected to be settled by a group annuity purchase, based on unadjusted CIA annuity purchase guidance	CPM2014 Combined with improvement scale CPM-B	4.72%	$5,829,786,536
Recalibration to reflect mortality rates for a typical group annuity purchase	CPM2014 Private with improvement scale CPM-B	4.57%	$5,829,370,227
Calculate final solvency liability for benefits expected to be settled by a group annuity purchase, based on adjusted mortality rates	CPM2014 Private, with a multiplier of 90%, and improvement scale CPM-B	4.57%	$5,960,028,426

For benefits that are expected to be settled by commuted value transfer

Determined in accordance with the *Standards of Practice for Pension Commuted Values* in effect at the date of the actuarial valuation.

No pre-retirement mortality has been assumed in order to approximate the value of pre-retirement death benefits.

Retirement/pension commencement

For active and disabled members :

For the benefits that are expected to be settled by a group annuity purchase

- Members eligible to retire: pension commences at the age that produces the highest actuarial value (including statutory grow-in rights).
- Members with age plus continuous service greater than or equal to 55 years: pension commences at the age that produces the highest actuarial value (including statutory grow-in rights).
- Other members: age that produces the highest actuarial value.

For benefits that are expected to be settled by commuted value transfer

- Members eligible to retire: 50% at the age that produces the highest actuarial value, and 50% at the earliest unreduced pension commencement age (including statutory grow-in rights).
- Members with age plus continuous service greater than or equal to 55 years: 50% at the age that produces the highest actuarial value, and 50% at the earliest unreduced pension commencement age (including statutory grow-in rights).
- Other members: 50% at the age that produces the highest actuarial value, and 50% at the earliest unreduced pension commencement age.

For deferred vested members :

- Members are assumed to retire at the earliest age at which they qualify for an unreduced pension.

For the benefits that are expected to be settled by a group annuity purchase, this is in accordance with the CIA Standards and legislative requirements, and consistent with the expected assumption that would have been used by insurers to price the group annuity. For benefits that are expected to be settled by commuted value transfers, this assumption is in accordance with the Canadian Institute of Actuaries' Standards of Practice for Pension Commuted Values.

Percentage of members with an eligible spouse at pension commencement and electing joint and survivor pension form

See rationale for going concern assumptions in Appendix C.

Years male spouse older than female spouse

See rationale for going concern assumptions in Appendix C.

Percentage of members receiving settlement by commuted value transfer

This assumption has been determined by considering the benefit provisions of the plan, legislative requirements to offer specific settlement options to various classes of members, and, in particular, the options available to members upon plan windup.

The assumption also reflects the expectation that members further from retirement are more likely to elect to settle their pension benefit by a commuted value transfer, while members closer to retirement are more likely to elect to settle their pension benefit through a group annuity purchase where this option is available. In addition, the assumption reflects past plan experience for terminating and retiring members.

Provision for expenses

Allowance was made for normal administrative, actuarial, legal and other costs which would be incurred if the plan were to be wound up (excluding costs relating to the resolution of surplus or deficit issues). The actuarial valuation is premised on a scenario in which the employer continues to operate after the windup date. In establishing the allowance for plan windup costs, certain administrative costs were assumed to be paid from the pension fund (consistent with past practice) while other costs were assumed to be borne directly by the employer.

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Appendix E: Membership Data

	December 31, 2024	December 31, 2023
Active members		
• Number	6,625	6,271
• Average age	43.1	43.1
• Average service	11.0	11.1
• Annual payroll	$ 841,377,829	$ 772,051,190
• Average Salary	$ 127,000	$ 123,115
• Accumulated contributions with interest	$ 644,149,190	$ 571,633,197
Disabled members		
• Number	226	232
• Average age	53.7	53.1
• Average service	20.3	19.7
• Annual payroll	$ 25,518,999	$ 25,148,622
• Average Salary	$ 112,916	$ 108,399
• Accumulated contributions with interest	$ 18,287,763	$ 16,993,962
Suspended members		
• Number	37	33
• Average age	41.2	39.9
• Average service	4.0	3.0
• Annual payroll	$ 4,919,194	$ 4,393,849
• Average Salary	$ 132,951	$ 133,147
• Accumulated contributions with interest	$ 1,637,495	$ 1,112,076
Retired Members		
• Number	6,149	6,221
• Average Age	73.2	72.8
• Total Lifetime Annual Pension	$ 338,951,359	$ 332,693,613
• Average Lifetime Annual Pension[1]	$ 55,123	$ 53,479
• Total Temporary Annual Pension	$ 20,672,586	$ 22,666,528

		December 31, 2024		December 31, 2023
Beneficiaries and Survivors				
• Number		1,581		1,597
• Average Age		81.1		81.2
• Total Lifetime Annual Pension	$	53,878,297	$	52,551,763
• Average Lifetime Annual Pension[1]	$	34,079	$	32,907
• Total Temporary Annual Pension	$	386,599	$	495,791
Terminated Vested Members				
• Number		368		364
• Average Age		52.3		51.9
• Total Annual Pension[2]	$	5,014,483	$	4,876,082
• Average Annual Pension	$	13,626	$	13,396

Notes:

[1] Excluding temporary annual pension.

[2] Prior to application of Income Tax Act maximum pension limits.

The following distribution relates to active, disabled and suspended members. The following meanings have been assigned to:

- Age: Age as at December 31, 2024
- Credited Service: Credited service as at December 31, 2024
- Earnings: Pensionable earnings for the year beginning January 1, 2025

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		Credited Service								
Age		*0 - 4*	*5 - 9*	*10 - 14*	*15 - 19*	*20 - 24*	*25 - 29*	*30 - 34*	*35 +*	*Total*
< 25	Number	75								75
	Average Earnings	101,075								101,075
25 - 29	Number	484	36							520
	Average Earnings	110,600	126,615							111,709
30 - 34	Number	606	336	55						997
	Average Earnings	113,968	124,543	129,202						118,372
35 - 39	Number	389	355	475	136					1,355
	Average Earnings	114,923	122,385	131,278	139,476					125,075
40 - 44	Number	219	193	340	454	29				1,235
	Average Earnings	116,249	121,799	130,655	139,179	166,500				130,692
45 - 49	Number	125	120	167	291	128	17			848
	Average Earnings	113,043	122,311	129,464	140,765	146,211	133,792			132,524
50 - 54	Number	87	66	100	231	121	39	15		660
	Average Earnings	118,931	123,540	134,668	136,632	141,062	140,004	133,362		133,601
55 - 59	Number	65	54	64	185	109	39	76	35	627
	Average Earnings	110,606	126,523	127,229	133,921	142,207	131,904	134,896	137,020	131,790
60 - 64	Number	34	39	53	134	74	30	30	65	459
	Average Earnings	109,279	118,647	131,827	129,131	138,907	129,424	128,743	131,914	129,045
65 +	Number	11	7	12	34	20	4	8	16	112
	Average Earnings	125,494	126,799	120,899	132,537	135,236	122,291	133,458	146,277	132,384
Total	Number	2,095	1,206	1,266	1,465	481	129	129	117	6,888
	Average Earnings	113,175	123,165	130,769	137,383	143,652	133,727	133,197	135,286	126,570

Average Age = 43.4 Average Credited Service = 11.3

Review of Membership Data

The membership data were supplied by Hydro One Inc's third-party administrator, TELUS Health, as at December 31, 2024.

Elements of the data review included the following:

- ensuring that the data were intelligible (i.e., that an appropriate number of records was obtained, that the appropriate data fields were provided and that the data fields contained valid information);
- preparation and review of membership reconciliations to ascertain whether the complete membership of the plan appeared to be accounted for;
- review of consistency of individual data items and statistical summaries between the current actuarial valuation and the previous actuarial valuation;
- review of reasonableness of individual data items, statistical summaries and changes in such information since the date of the previous actuarial valuation; and
- comparison of the membership data and the plan's financial statements for consistency.

However, the tests conducted as part of the membership data review may not have captured certain deficiencies in the data. We have also relied on the certification of the plan administrator as to the quality of the data, as described below.

Missing, Insufficient or Unreliable Data

The review of membership data revealed that certain data elements were missing, insufficient or unreliable. The following adjustments and assumptions were applied to the data for purposes of the actuarial valuation:

- With respect to the pensioners that elected a joint and survivor pension option, the membership data supplied by TELUS Health as at December 31, 2024 had missing spousal information (i.e. the spouse's gender). The opposite gender to the pensioners' record has been applied to the data for the purposes of the actuarial valuation.

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Membership Reconciliation

	Actives	Disabled	Suspended	Terminated vested	Retired	Beneficiaries and survivors	Total
As at December 31, 2023	6,271	232	33	364	6,221	1,597	14,718
• New entrants (including re-employed)	524	0	0	0	0	0	524
• From disabled	12	(12)	0	0	0	0	0
• To disabled	(23)	23	0	0	0	0	0
• Transferred to DC plan	(6)	0	6	0	0	0	0
• Termination (with lumpsum)	(13)	0	(1)	(28)	0	0	(42)
• Termination (with pension)	(33)	(3)	(1)	37	0	0	0
• Termination (Death pending for election)	(1)	(2)	0	3	0	0	0
• Retirement	(104)	(12)	0	(7)	123	0	0
• Deceased (without beneficiary)	0	0	0	0	(100)	(114)	(214)
• Deceased (with beneficiary)	(2)	0	0	0	(95)	97	0
• New ex-spouse	0	0	0	0	0	1	1
• Data correction	0	0	0	(1)	0	0	(1)
• Net change	354	(6)	4	4	(72)	(16)	268
As at December 31, 2024	6,625	226	37	368	6,149	1,581	14,986

Appendix F: Summary of Plan Provisions

The following is an outline of the principal features of the plan which are of financial significance to valuing the plan benefits. This summary is based on the plan document as at November 7, 2016 and amendments up to and including the valuation date, as provided by Hydro One Inc. It is not a complete description of the plan terms and should not be relied upon for administration or interpretation of benefits. For a detailed description of the benefits, please refer to the plan document.

F.1 DB Provisions

Membership

The following categories of employees are members of the Pension Plan:

a) All regular employees (see Note 1a and Note 1b);

b) Employees for whom the Office and Professional Employees International Union was the bargaining agent prior to July 30, 1982;

c) Continuing construction employees who were members admitted to the Ontario Electricity Financial Corporation Pension Plan and its predecessors;

d) Employees who became continuing construction clerical employees after July 29,1982 and before August 8, 1984;

e) Employees who have completed three months of continuous employment as a probationary employee (see Note 1a and Note 1b).

Note 1a: Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 are eligible after completing three months of continuous employment but are not required to join the Pension Plan.

Note 1b: Management employees who were not eligible to elect to become a member of the Pension Plan on or after September 30, 2015 are no longer eligible to join the Pension Plan. Additionally, effective March 1, 2021, any employee who became a member of the plan on or after September 30, 2015 while represented by the Power Worker's Union or the Society of United Professionals and later becomes employed at the management level shall cease to accrue service in the plan but will continue to earn service for the purposes of the early retirement subsidies of the plan. Additionally, pensionable earnings at the date of the employment as a management level employee will be increased thereafter with by 100% of the Consumer Price Index Canada.

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Any other employee who has completed twenty-four months of continuous employment and who has at least 700 hours of employment or earnings of 35% of the Year's Maximum Pensionable Earnings ("YMPE"), as defined under the Canada Pension Plan in each of the two previous consecutive calendar years, may elect to become a member of the Pension Plan.

Normal Retirement Date

a) Female members whose continuous employment commenced prior to January 1, 1976: The first day of the month when she in fact retires, coincident with or next following the attainment of age 60 or any subsequent month up to the month coincident with or next following her 65th birthday.

b) All other members: The first day of the month coincident with or next following the attainment of age 65.

Amount of Accrued Pension

Life Pension

a) 2% of the member's "high three-year average" (see Note 6) for each year of credited service, subject to a maximum of 35 years (see Note 2 and Note 3).

Note 2: For Management employees hired on or after January 1, 2004, and Society represented employees hired on or after November 17, 2005 the reference to "high three-year average" is changed to "high five-year average" for pensionable service while a Management or Society-represented employee.

Note 3: For members represented by PWU, the Society and Management employees hired before January 1, 2004, for service accrued after March 31, 2025 for current employees and new hires, the benefit calculated will be determined using "high five-year average" (updated from "high three-year average" used for service accrued until March 31, 2025) as outlined in the respective collective agreements.

LESS

b) 0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 6) for each year of credited service included in (a) above subsequent to December 31, 1965, subject to a maximum of 35 years – see Note 4.

Note 4: Effective July 1, 2001, for members of the PWU, and effective January 1, 2004, for Society represented members hired before November 17, 2005; the factor is reduced from 0.625% to 0.50%.

Bridge Pension (see Note 5)

0.625% of the member's "high five-year average" up to the "average YMPE" (see Note 6) for each year of credited service included in (a) above, subject to a maximum of 30 years, multiplied by 35, and divided by 30. This is generally payable until age 65.

The bridge benefit is reduced for early retirement in accordance with the same early retirement reduction provision applicable to the early retirement life pension described below.

Note 5: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, no bridge pension is payable for pensionable service while a Management or Society-represented employee. Effective January 1, 2018, Society represented employees hired on or after November 17, 2005 will be entitled to a bridge benefit equal to 0.625% up to the average YMPE for each year of service from January 1, 2018 onward while the member is earning a benefit under the basic formula.

Note 6: "High three-year average"/ "high five-year average" is the average of the member's base annual earnings plus bonuses up to a set percentage during the 36/60 consecutive months when the base earnings were highest. For earnings after 1999, the percentage of bonus under the performance achievement plan included in pensionable earnings is 50%. The "average YMPE" is the average of the YMPE's during the 60 consecutive months when the base earnings were highest.

Early Retirement

<u>Age Plus Service</u> (See Note 7 and Note 8)

A member may retire prior to the normal retirement date without any reduction in the accrued pension, if the sum of the member's age and years of continuous employment is equal to or greater than 82 or the member has 35 years of continuous employment, whichever occurs first (see Note 7).

Note 7: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, retirement without reduction is available when the sum of the employee's age and years of pensionable service is equal to or greater than 85 or the employee has 35 years of pensionable service, whichever occurs first.

Note 8: For members represented by PWU and Management employees hired before January 1, 2004, for service accrued after March 31, 2025, the early retirement criteria for an unreduced pension will be changed from the sum of the employee's age and years of pensionable service is equal to or greater than 82 to the 85 as outlined in the collective agreement.

<u>25 or More Years of Continuous Employment</u> (see Note 9)

A member who does not qualify for the early retirement provisions above who is at least age 55 and has 25 or more years of continuous employment may retire prior to age 60, in which case the member's

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accrued pension is reduced by 3% for each year by which early retirement precedes age 60. These reductions also apply to members who elected a deferred pension when they left the Pension Plan and had 25 or more years of continuous employment.

Female Members with More Than 15 Years or Other Members with 15 or More Years but Less than 25 Years of Continuous Employment (see Note 9)

A female member whose continuous employment commenced prior to 1976 with at least 15 years of continuous employment, or any other member with 15 or more years but less than 25 years of continuous employment, who does not qualify for any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. In such a case the member's accrued pension is reduced by 2% for each year up to five years and 3% for each additional year by which the early retirement date precedes the member's normal retirement date.

These reductions apply with respect to a female member whose employment commenced prior to 1976 and who has a deferred pension and at least 25 years of continuous employment at retirement. For any other members who have a deferred vested pension and have fewer than 25 years of continuous employment and are at least age 55 when they request that the pension payments begin, the deferred vested pension will be actuarially reduced (unless the member was eligible for an unreduced early retirement provision in effect when the member terminated active employment).

Other Members

A member, who does not qualify under any of the previously mentioned early retirement provisions, may retire within 10 years of normal retirement date. If the retirement occurred prior to July 1, 2012, the member is also required to have at least two years of Pension Plan membership. In such a case, the pension is the actuarial equivalent of the member's deferred pension provided that the reduction shall not be less than the minimum early retirement reduction required under the *Income Tax Act* (Canada).

Terminated Members with Deferred Pensions

A terminated member with a deferred pension may retire under any of the previously mentioned provisions for early retirement without reduction provided that such provision was in effect on the date of termination. In addition, if the member's employment is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the *Pension Benefits Act* (Ontario) ("PBA"), resulting in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination.

Note 9: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005 all references to "continuous employment" are to be replaced with "pensionable service" for service while a Management or Society-represented employee.

Postponed Retirement

Members who work past their normal retirement date shall continue to accrue benefits until December 1st of the calendar year they reach age 71 (or the Income Tax Act age limit, if different), they reach the 35 year service limit, or they terminate employment, whichever occurs first. If a member reaches 35 years of service and ceases contributions to the Pension Plan, service after 35 years is not counted in the calculation of the member's pension, but the pension is calculated using the member's base earnings up to the date of postponed retirement. If the member works past age 71, the member's pension will commence to be paid not later than December 1st of the year in which the member turns age 71.

Pension Increases

Pension increases of 100% (see Note 10) of the increase in the Consumer Product Index ("CPI") (Ontario), for the 12-month period ending in June of the previous year , will be given every January 1 to pensioners, beneficiaries and terminated employees with deferred pensions to an annual maximum of 8% each year after 1999. Any excess will be carried forward to use in future years up to the 8% limit.

Note 10: For Management employees hired on or after January 1, 2004 and Society represented employees hired on or after November 17, 2005, pension increases of 75% CPI (Ontario) for the 12-month period ending in June of the previous year will be given every January 1, to an annual maximum increase of 5%, with no carry forward.

Disability

A totally disabled employee receives benefits from an income replacement plan and ceases to contribute to the Pension Fund, but continues to accrue credited service. For this member, the base annual earnings for pension purposes are deemed to be increased by the same percentage increases described for pensions above.

Employee Contributions

Members contribute based on their employee group at the following rates until they complete 35 years of credited service and up to the limits established by the Income Tax Act :

Employee Group	Management hired on/after Jan. 1, 2004	Management hired pre Jan. 1, 2004	Society hired on/after Nov. 17, 2005	Society hired pre Nov. 17, 2005	Power Workers Union
Up to YMPE	8.25%	8.75%	8.25%	8.75%	8.75%
Above YMPE	10.75%	11.25%	10.75%	11.25%	11.25%

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Death Before Retirement

No Surviving Spouse or Eligible Dependent Children

The beneficiary or estate will receive the following:

- For pre-1987 service: a cash refund of the member's contributions plus interest.
- For post-1986 service: a lump sum equal to the commuted value of the member's pension earned since 1986, plus a refund of any excess contributions.

For deaths occurring on or after July 1, 2012, the beneficiary or estate will be entitled to the death benefits described above regardless of the member's length of service.

Surviving Spouse (see Note 12)

Fewer than two years of Pension Plan membership and less than 10 years of continuous employment

The beneficiary or estate receives a cash refund of the member's contributions plus interest.

Fewer than two years of Pension Plan membership and more than 10 years of continuous employment

The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned to the date of death.

More than two years of Pension Plan membership, but less than 10 years of continuous employment

For pre-1987 service: The beneficiary or estate receives a cash refund of the member's contributions plus interest.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:

a. a lump-sum payment equal to the commuted value of the pension earned after 1986, or

b. an immediate or deferred pension with a commuted value equal to pension earned after 1986.

More than two years of Pension Plan membership, and more than 10 years of continuous employment

For pre-1987 service: The surviving spouse receives an immediate pension of 66.67% of the member's accrued pension earned prior to 1987.

For post-1986 service:

- The beneficiary or estate receives a refund of any excess member contributions; and
- The surviving spouse chooses either:
- a lump-sum payment equal to the commuted value of the pension earned after 1986, or
- an immediate or deferred pension with a commuted value equal to pension earned after 1986. The immediate pension will not be less than 66.67% of the pension earned after 1986.

Note 12: For deaths occurring on or after July 1, 2012, the surviving spouse's entitlement to death benefits for post-1986 service shall be determined without reference to whether the member had more or less than two years of Pension Plan membership. In addition, for deaths occurring on or after July 1, 2012, if the surviving spouse is entitled to the death benefits in respect of the member's post-1986 service, the surviving spouse is also entitled to an amount equal to the member's contributions, with interest, in respect of pre-1987 service, rather than the designated beneficiary or estate.

Dependent Children, No Surviving Spouse

If the member completed 10 years of continuous employment, the survivor's pension is payable to the surviving spouse until death or, if there is no eligible spouse, to the dependent children until age 18 (longer if disabled or in full-time attendance at a school or university). The total benefits paid are subject to a minimum of the member's contributions with interest. A payment of the commuted value of the member's deferred pension less the commuted value of the pension payable to any dependent children is made to the beneficiary or estate.

Death After Retirement

A survivor's pension, being an amount equal to 66.67% of the pension to which the member would have been entitled, is payable on death after retirement to the surviving spouse, subject to other options chosen at the time of retirement. If the survivor spouse subsequently dies and is survived by the dependent children, or the member does not have a surviving spouse and is survived only by dependent children, the 66.67% survivor pension is split among the dependent children and is payable to age 18 (longer if disabled or in full-time attendance at a school or university).

If the member does not have a surviving spouse at retirement, the normal form of pension is a pension payable for life with a guarantee of 60 payments.

Optional forms of pension are available on an actuarially equivalent basis.

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Termination of Employment (see Note 14)

Less Than One Year of Pension Plan Membership

A cash refund of the member's contributions plus interest.

More Than One Year But Fewer Than Two Years of Pension Plan Membership

The member is entitled to elect a cash refund of the member's contributions plus interest, or may leave the earned pension benefit in the Pension Plan to be paid upon retirement.

More Than Two Years but fewer than 10 Years of Pension Plan Membership and, either under Age 45, or Fewer Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to a cash refund of the member's contributions plus interest, or may leave all of the earned pension benefit in the Pension Plan until retirement.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More Than Two Years but fewer than 10 Years of Pension Plan Membership, and Age 45 or Older with More Than 10 Years of Continuous Employment

For pre-1987 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) 75% of the commuted value of the pension and receive a refund of 25% of the commuted value of your earned pension; or to leave 75% of the earned pension benefit in the Pension Plan until retirement, and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More Than 10 Years of Pension Plan Membership, But Younger Than Age 45

For service from 1965 to 1986: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value of the earned pension.

For post-1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer (see Note 13) the commuted value of the earned pension.

More than 10 Years of Pension Plan Membership and Age 45 or Older

For pre-1965 service: the member is entitled to a cash refund of the member's contributions plus interest; or to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value.

For service from 1965 to 1986: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to leave 75% of the earned pension benefit in the Pension Plan until retirement and receive a refund of 25% of the commuted value; or to transfer (see Note 13) the greater of the commuted value of 75% of the earned pension or the member's contributions with interest and receive a refund of 25% of the commuted value of the earned pension.

For post 1986 service: the member is entitled to leave all of the earned pension benefit in the Pension Plan until retirement; or to transfer the commuted value of the earned pension.

If a member is terminated on or after July 1, 2012, the member may be eligible for grow-in benefits under the PBA, which could result in the member being entitled to early retirement benefits under the Pension Plan that the member would not otherwise be eligible to receive on the date of termination. If grow-in benefits apply, this may affect the value of the benefits the member is entitled to receive on termination of employment or retirement.

Note 13: Amounts must be transferred to a pension fund related to another pension plan, a prescribed retirement savings arrangement, or a life annuity which does not commence before the earliest date on which the member would have been entitled to retire.

Note 14: In respect of terminations occurring on or after July 1, 2012, a member is entitled to the earned pension benefits for all service regardless of length of Pension Plan membership, continuous employment or age.

Excess Contributions

Upon the earliest of termination of employment, death or retirement, the amount by which the member's post-1986 contributions with interest exceed 50% of the commuted value of the vested deferred pension accrued after 1986 is refunded to the member (or to the spouse, beneficiary or estate, as applicable in the case of death before retirement).

Upon termination of employment, if a member who has attained age 45 and completed 10 or more years of continuous employment elects to fully divest the pension accrued prior to 1987, the member is entitled to receive the amount by which the contributions with interest made after 1964 but prior to 1987 exceeds the commuted value of the pension accrued after 1964 but prior to 1987. (See Note 15)

Note 15: For terminations occurring on or after July 1, 2012, entitlement to excess contributions in respect of pre-1987 service shall be determined without reference to age or years of continuous employment.

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Maximum Benefits

The benefits in respect of continuous employment after 1991 are limited to the maximum allowable under the Income Tax Act (Canada).

Special Considerations for Society Represented Members who Transferred from the Inergi LP Customer Services Operations Pension Plan, Vertex Customer Management (Canada) Limited Pension Plan or the Inergi LP Pension Plan

Notwithstanding the plan provisions described in this section, for service from the date of transfer, Society represented members who transferred from the above mentioned pension plans will participate in provisions applicable to Society represented employees hired on or after November 17, 2005.. For service prior to the date of transfer the benefits will be determined based on the provisions applicable under the prior plans which are the same as those applicable to Management employees hired before January 1, 2004 and Society represented employees hired before November 17, 2005, respectively.

Special Considerations for Employees Represented by Power Worker's Union or the Society of United Professionals who Transfer to Management Positions on or After March 1, 2021

Effective March 1, 2021, any employee who became a member of the plan on or after September 30, 2015 while represented by the Power Worker's Union or the Society of United Professionals and later becomes employed at the management level shall cease to accrue credited service in the plan. However such member will continue to earn service for the purposes of determining their benefit entitlement under the early retirement provisions of the plan. Additionally, pensionable earnings after the date of transfer of employment to a management level employee will be determined based on pensionable earnings in effect immediately prior to the date of transfer of employment, increased annually at 100% of the Consumer Price Index Canada.

Appendix G: Sensitivity Analysis and Other Disclosures

G.1 Sensitivity Information

Amounts determined with a discount rate 1% lower:

Going Concern actuarial liability (prior to application of PfAD)	$ 7,752,772,495
• As percent increase	14.1%
Solvency actuarial liability	$ 7,817,085,948
• As percent increase	12.4%
Normal actuarial cost in respect of benefit accruals (prior to application of PfAD)	$ 177,382,143
• As percent increase	29.8%
Employer normal actuarial cost as a percentage of payroll	12.8%

G.2 Solvency Incremental Cost

Solvency incremental cost (up to the date of the next actuarial valuation)	$ 840,405,407

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G.3 Provision for Adverse Deviations Level

Target Asset Allocation for Fixed Income Assets

The information below as at December 31, 2024 has been used to determine the provision for adverse deviations level. The fixed income investments listed below meet the minimum credit rating prescribed by Pension Legislation.

	Target asset allocation	Fixed income allocation	Non-fixed income allocation	Fixed income weight
Asset classes				
• Global equities	30.0%	0.0%	30.0%	0%
• Private equities	10.0%	5.0%	5.0%	50%
• Bonds and debentures	28.0%	28.0%	0.0%	100%
• Real estate and infrastructure	25.0%	12.5%	12.5%	50%
• Private debt	5.0%	2.5%	2.5%	50%
• Cash and accrued income	2.0%	2.0%	0.0%	100%
Total	100%	50.0%	50.0%	

Benchmark Discount Rate

Components	Rate
CANSIM V39056	3.33%
Risk premium on non-fixed income assets[1]	2.50%
Risk premium on fixed income assets[2]	0.75%
Diversification allowance	0.50%
Benchmark discount rate	7.08%

Notes:

[1] 5.00% of the non-fixed proportion of the assets.

[2] 1.50% of the fixed proportion of the assets.

Provision for Adverse Deviations Level

Components	Provision for adverse deviations level
Fixed	4.0%
Asset mix based	3.0%
Benchmark discount rate based[1]	0.0%
Provision for adverse deviations level[2]	7.0%

Notes:

[1] Reflects going concern discount rate, prior to adjustment for expenses and rounding if any, less benchmark discount rate (subject to a minimum of zero), multiplied by the actuarial liability duration.

[2] The provision for adverse deviations is applied to the actuarial liability and total normal cost, excluding any portion for future indexation.

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G.4 Effects of Plausible Adverse Scenarios

In accordance with CIA Standards of Practice, the risk assessments below have been performed only for the going concern valuation of the plan.

Interest Rate Risk

Yields on the plan's fixed income investments have been assumed to decline immediately by 92 basis points on a weighted average basis, resulting in a reduction in the going concern discount rate of 26 basis points. For this purpose, fixed income investments have been deemed to include only marketable long bonds, private debt and cash. The market values and expected returns for equities, real estate and infrastructure have been assumed to be unaffected by the bond yield changes.

The provision for adverse deviations (PfAD) has been assumed to increase from 7.0% to 14.1% due to the change in bond yields.

The smoothed value of assets adopted under the going concern basis has been adjusted to reflect the changes in fixed income investment values under this interest rate risk scenario.

The adverse scenario for interest rate risk is based on the capital market assumptions from WTW's capital market model, with a 10th percentile scenario used for each relevant asset class independently.

No allowance has been made for any other effects on the actuarial liability or total normal cost due to the change in bond yields.

Deterioration of Asset Values

Market values of equities, real estate and infrastructure have been assumed to decline immediately by 16.26% on a weighted average basis. Market values of marketable long bonds, private debt and cash, expected future returns for all asset classes, as well as the going concern discount rate, have been assumed to be unaffected by this deterioration of asset values.

The smoothed value of assets adopted under the going concern basis has been adjusted to reflect this immediate deterioration of asset values.

No allowance has been made for any other effects of the deterioration of asset values.

The adverse scenario for a deterioration of asset values is based on the capital market assumptions from WTW's capital market model, with a 10th percentile scenario used for each relevant asset class independently.

Longevity Risk

Longevity risk has been assessed by applying a multiplier of 78.9% to the mortality rates disclosed in Appendix C (to be compounded with the existing multiplier(s)).

No allowance has been made for any effects on asset values or any effects on the actuarial liability or total normal cost other than the mortality assumption change.

Effects

The effects of the plausible adverse scenarios above on the funded status of the plan and on the total normal cost is shown in the following table. For this purpose, the actuarial liability and total normal cost reflect application of the PfAD.

Scenario	Baseline	Interest Rate Risk	Deterioration of Asset Values	Longevity Risk
Going concern discount rate	6.80%	6.54%	6.80%	6.80%
PfAD	7.0%	14.1%	7.0%	7.0%
Weighted average fixed income yield change	N/A	(0.92)%	N/A	N/A
Fixed income asset value change	N/A	13.65%	N/A	N/A
Non-fixed income asset value deterioration	N/A	N/A	(16.26)%	N/A
Market value of assets	$ 9,331,959,000	$ 9,777,793,341	$ 8,345,664,253	$ 9,331,959,000
Going concern value of assets	$ 9,342,673,000	$ 9,431,840,000	$ 9,145,414,000	$ 9,342,673,000
Actuarial liability (including PfAD)	$ 7,187,507,359	$ 7,855,308,406	$ 7,187,507,359	$ 7,369,843,666
Actuarial surplus (unfunded actuarial liability) after PfAD	$ 2,155,165,641	$ 1,576,531,594	$ 1,957,906,641	$ 1,972,829,334
Total normal actuarial cost (including PfAD)	$ 144,306,913	$ 162,788,189	$ 144,306,913	$ 146,347,197

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G.5 PBGF Data

The following information is required to be disclosed under section 14 (8.0.4) (h) of the Regulation to the *Pension Benefits Act (Ontario)*, in order to provide information regarding the PBGF exposure related to the plan. The information shown is in respect of Ontario plan members only.

	Retired members and beneficiaries		Other members		Total
Number of members		7,730		7,256	14,986
Number of members with total lifetime and temporary monthly pension equal to or less than $1,500		935		3,174	4,109
Modified PBGF liability		$ 1,513,101,910		$ 1,025,454,898	$ 2,538,556,808
Percentile amounts	Monthly pension	PBGF liability	Monthly pension	PBGF liability	
• 10th percentile	$ 1,260	$ 63,802,356	$ 138	$ 7,145,634	
• 20th percentile	2,305	227,700,464	430	28,793,522	
• 30th percentile	3,014	460,761,524	859	69,751,102	
• 40th percentile	3,710	774,154,756	1,285	138,041,393	
• 50th percentile	4,276	1,166,435,575	1,865	249,635,181	
• 60th percentile	4,947	1,635,965,004	2,551	422,867,522	
• 70th percentile	5,626	2,221,504,434	3,070	668,606,524	
• 80th percentile	6,466	2,893,625,430	3,589	984,624,055	
• 90th percentile	7,621	3,705,261,544	4,567	1,397,705,666	
Amount of largest lifetime plus temporary monthly pension					$ 25,588

Comments:

- The modified PBGF liability is the amount of PBGF liability in respect of monthly pension amounts up to $1,500. For members whose pension benefits have not yet commenced, the $1,500 limit is applied based on the pension amounts that would be payable at the member's assumed pension commencement age(s) (reflecting early retirement or other reductions as applicable) in accordance with the solvency and hypothetical windup assumptions.
- The PBGF liability for each percentile includes liabilities for members with total lifetime and temporary pensions equal to or less than the corresponding monthly pension amounts (i.e., all liabilities for members with total pensions exceeding these amounts are excluded). For members whose pension benefits have not yet commenced, the monthly pension amounts and corresponding PBGF liabilities are based on the accrued pension benefit (prior to any early retirement or other reductions).

Actuarial Information Summary

See the instructions for completing this form. If an item does not apply, enter N/A.

Part I – Plan Information and Contributions

A. 001. Name of registered pension plan
Hydro One Pension Plan

B. 002. Registration number
Canada Revenue Agency: 1059104 Other:

C. 003. Is this plan a designated plan?
☐ Yes ☑ No

D. 004. Valuation date of report
Year Month Day
2024 12 31

E. 005. End date of period covered by report
Year Month Day
2027 12 30

F. 006. Purpose of the report (indicate all reasons for which the report was prepared)
☐ Initial report for a newly established plan
☑ Regular (triennial or annual) report for an ongoing plan
☐ Interim report in respect of an amendment to an ongoing plan
☐ Partial termination
☐ Termination
☐ Conversion
☐ Other (explain)

G. Contributions (prior to application of any credits or surplus) for covered period

Periods (see instructions)	Period 1	Period 2	Period 3	Period 4
007. Period start date (YYYY-MM-DD)	2025-01-01	2026-01-01	2027-01-01	
008. Period end date (YYYY-MM-DD)	2025-12-31	2026-12-31	2027-12-30	
Normal cost (defined benefit provision) **009.** Members	78,337,143	77,951,374	78,133,464	
010. Employer	65,969,770	66,890,796	69,212,249	
010a. Explicit expense allowance included in employer normal cost above				
Normal cost (money purchase provision) **011.** Members				
012. Employer				
Special payments Special payments for going-concern unfunded liability and solvency deficiency **013.** Employer	0	0	0	
013a. Members	0	0	0	
Fixed contributions **014.** Estimated dollar amounts of fixed employer and, if applicable, member contributions (defined benefit provision)				
014a. Estimated dollar amounts of fixed employer and, if applicable, member contributions (money purchase provision)				

Part II – Membership and Actuarial Information

H. Membership information	Number	Average age	Average pensionable service	Average salary	Average annual pension
015. Active members	6,888	43.40	11.30	126,570	N/A
016. Retired members	7,730	74.80	**N/A**	**N/A**	50,819
017. Other participants	368	52.30	**N/A**	**N/A**	13,626

I. Actuarial basis for going-concern valuation (see instructions)

020. Asset valuation method
☐ Market ☑ Smoothed Market ☐ Book ☐ Book and Market combination ☐ Other (specify)

021. Liability valuation method
☑ Accrued benefit (unit credit) ☐ Entry age normal ☐ Individual level premium ☐ Aggregate ☐ Attained Age
☐ Other (specify)

I. Actuarial basis for going-concern valuation (continued)

Selected actuarial assumptions

Where a flat rate is used, enter the rate under Ultimate rate and N/A under Initial rate and Number of years.

Valuation interest rate	Initial rate (%)	Number of years	Ultimate rate (%)
025. Active members	N/A	N/A	6.80
026. Retired members	N/A	N/A	6.80
027. Rate of indexation	N/A	N/A	2.00
028. Rate of general wage and salary increase	N/A	N/A	2.50
029. YMPE escalation rate	N/A	N/A	3.00
030. Income Tax Regulations' maximum pension limit escalation	N/A	N/A	3.00
031. Rate of CPI increase	N/A	N/A	2.00

032. Components of going-concern valuation interest rate on line **025** and/or **026**

a) Expected investment return on plan assets, excluding additional return from active investment management ..... 6.94 %

b) Expected additional return from active investment management ..... 0.00 %

c) Expected expenses paid from the fund for active investment management ..... 0.00 %

d) Expected investment expenses other than those reported on line **032 (c)** ..... -0.06 %

e) Other expected expenses including administrative expenses ..... -0.08 %

f) Effect of rebalancing and diversification, if any ..... 0.00 %

g) Margins for adverse deviations ..... 0.00 %

h) Other components ..... 0.00 %

i) Net going concern valuation interest rate ..... 6.80 %

035. Year Income Tax Regulations' maximum pension limit escalation commences 2026

036. Mortality table

☐ 1994 GAM Static ☐ 1994 Group Annuity Reserving (GAR) ☐ 1994 UP ☐ 80% of 1983 GAM ☐ CPM2014

☐ CPM2014Publ ☑ CPM2014Priv ☐ Other (specify) _____

036a. Improvement scale

Has a projection of mortality improvement been made? ..... ☑ Yes ☐ No

i) Has an assumption of generational mortality improvements been made? ..... ☑ Yes ☐ No

ii) If applicable, what is the year in which the mortality improvements have been projected? ..... ____

iii) Which scale have you used?

☐ Scale AA ☐ Scale CPM-B ☐ Scale CPM-B1D2014 ☑ Other (specify) MI-2024

036b. Adjustment to the mortality table

i) Has an adjustment to the mortality table been made? ..... ☑ Yes ☐ No

ii) If **yes**, which percentage did you apply to ..... Male 90.00 Female 90.00

037. Allowance for promotion, seniority, and merit increases

☐ Included in (line **028**) above ☑ Separate scale based on age or service ☐ No allowance

038. Allowance for expenses

038a. Allowance for investment expenses

☑ Implicit ☐ Explicit ☐ Both explicit and implicit

038b. Allowance for administrative expenses

☑ Implicit ☐ Explicit ☐ Both explicit and implicit

039. If a multi-employer plan, number of hours of work per member per plan year ..... _____

040. Was a withdrawal scale used? ..... ☑ Yes ☐ No

041. Were variable retirement rates used? ..... ☑ Yes ☐ No

042. If **no**, what is the assumed retirement age? ..... _____

J. Actuarial basis for solvency valuation

Valuation interest rate	Initial rate (%)	Select period	Ultimate rate (%)
045. Benefits to be settled by lump sum transfer	3.90	10	4.50
046. Benefits to be settled by purchase of deferred annuity	N/A	N/A	4.57
047. Benefits to be settled by purchase of immediate annuity	N/A	N/A	4.57
048. Rate of indexation	N/A	N/A	N/A

049. Mortality table

Lump sum: ☐ 1994 UP Generational ☐ CPM2014Priv ☑ CPM2014 ☐ CPM2014Publ ☐ Other (specify) _____

Annuity Purchase: ☐ 1994 UP Generational ☐ CPM2014Priv ☐ CPM2014 ☐ CPM2014Publ ☑ Other (specify) 90% CPM2014Priv

049a. Improvement scale used

Lump sum: ☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) _____ ☐ None

Annuity Purchase: ☐ Scale AA ☑ Scale CPM-B ☐ Scale CPM-B1D2014 ☐ Other (specify) _____ ☐ None

K. Balance sheet information (DB provisions, see instructions)

050. Market value of assets, adjusted for receivables and payables	9,331,959,000
051. Amount of contributions receivable included in market value above	0
Going-concern valuation	
052. Going-concern assets	9,342,673,000
053. Optional ancillary contributions account balance included in going-concern assets above for a flexible pension plan (if applicable)	0
Going-concern liabilities	
060. For active members	1,866,018,971
061. For retired members	4,876,031,769
062. For other participants	49,868,598
063. For optional ancillary benefits to be provided under a flexible pension plan (if applicable)	0
064. Reserves	
064a. Expenses	0
064b. Ad-hoc indexing	0
064c. Provision for adverse deviation	395,588,021
064d. Other (Specify) _____	
070. Net funded position—surplus/deficit	2,155,165,641
071. Additional voluntary contributions	0
072. Money purchase assets (if applicable)	0

Solvency valuation

Complete lines **080** to **100** only if the report contains an explicit solvency valuation

Solvency assets	
080. Solvency assets with adjustment for expense provision, if any	9,323,959,000
081. Amount of wind-up expense provision reflected in line **080**	8,000,000
082. Optional ancillary contributions account balance included in solvency assets above for a flexible pension plan (if applicable)	0
Solvency liabilities	
090. For active members	2,088,582,558
091. For retired members	4,811,578,466
092. For other participants	53,123,685
093. For optional ancillary benefits to be provided under a flexible pension plan (if applicable)	0
094. Reserves	
094a. Expenses	0
094b. Other (Specify) _____	
100. Net solvency position—surplus/deficit	2,370,674,291
101. Incremental cost	280,135,136

If the plan provides benefit increases coming into effect during the period covered by the report but after the valuation date, have those increases been reflected in:

102. The going-concern liabilities in lines **060** to **064**? ☐ Yes ☐ No ☑ N/A

103. The solvency liabilities in lines **090** to **094**? ☐ Yes ☐ No ☑ N/A

Discount rate sensitivity

	Change in percentage using discount rate 1% lower	Change in amount using discount rate 1% lower	Change in amount using discount rate 1% higher
104. Going-concern liabilities	14.10	960,853,157	
105. Normal cost	29.80	40,773,147	
106. Solvency liabilities	12.40	863,801,239	

107. Duration of the portion of the liabilities assumed to be settled through the purchase of annuities 10.10

L. Actuarial gains or losses

110. Was a gain/loss analysis done? ☑ Yes ☐ No

111. If line **110** is **yes**, indicate the date of the last filed funding valuation report and the net funded position as of that date ..... Year 2023 Month 12 Day 31 1,966,723,880

If line **110** is **yes**, indicate amount of gain or loss due to:

112. interest on surplus (unfunded liability) 127,837,052

113. special payments made 0

114. amount used for contribution holiday 0

115. change in actuarial assumptions 42,802,731

116. change in the asset valuation method 0

117. change in liability valuation method 0

118. plan amendments/changes 0

119. investment experience ..... (65,070,964)

120. retirement experience 3,600,587

121. mortality experience 7,049,598

122. withdrawal experience ..... (5,367,540)

123. salary increase experience 2,635,462

124. optional ancillary contributions forfeited .....

Are there major contributing sources other than lines **112** to **124** above (if **yes**, specify)

125. Change in PfAD 35,035,251

126. Cost-of-living adjustment 22,853,751

127. all other sources (combined) 17,065,833

M. Subsequent events

135. Are there any subsequent event(s) that have not been reflected in the valuation? (refer to SOP) ☐ Yes ☑ No

N. Statements of opinion

136. Does the report include the statements of opinion required by the SOP (data, assumptions, methods, accepted actuarial practice)? ☑ Yes ☐ No

136a. Are any of the actuary's statements of opinion qualified? ☐ Yes ☑ No

Part III – Information required by the Financial Services Regulatory Authority of Ontario

O. Additional valuation information

For purposes of Part III, the Regulation refers to the Regulation 909, R.R.O. 1990, as amended except as otherwise provided.

Going-concern valuation

137. Are benefits under the pension plan provided by an annuity purchase? ☐ Yes ☑ No

138. If line **137** is **yes**,

a) Enter the total asset value of the buy-in annuities as reported in the actuarial valuation report

b) Enter the total liabilities related to the buy-in annuities as reported in the actuarial valuation report

c) Enter the total asset value of the non-discharged buy-out annuities as reported in the actuarial valuation report

d) Enter the total liabilities related to the non-discharged buy-out annuities as reported in the actuarial valuation report

e) Have any annuities been discharged under OPBA section 43.1 since last valuation date? ☐ Yes ☐ No

If yes,

i) How many annuity discharge transactions have been made since the last valuation date?

ii) Enter the total premium of the buy-out annuities if the purchase was made since the last valuation date

iii) Enter the going-concern liabilities related to the annuity discharge at the time of purchase.

iv) Enter the top-up contributions required as per section 4 of Ontario Regulation 193/18.

139.1. Is the plan required to report the amount of Available Actuarial Surplus? ☑ Yes ☐ No

i) If **yes**, enter the amount of Available Actuarial Surplus 0

139.2. Breakdown of the total special payyments with respect to the going-concern unfunded liability and plan amendment

Special payments with respect to:	Period 1	Period 2	Period 3	Period 4	Present value of the special payments on the going-concern basis
Going-concern unfunded liability **139.2a** Members	0	0	0		0
139.2b Employer	0	0	0		0
Plan amendment **139.2c** Members	0	0	0		0
139.2d Employer	0	0	0		0

Provision for Adverse Deviations

139.3. Is the Provision for Adverse Deviations of the plan zero or deemed to be zero? ☐ Yes ☑ No

If **no**, complete lines **139.4** to **139.9**

139.4. Is the plan closed as determined in subsection 11.2(2) component A of the Regulation? ☐ Yes ☑ No

139.5 Combined target asset allocation for fixed income assets as determined in subsection 11.2(4) component J of the Regulation 50.00 %

139.6 Plan's duration of going-concern liabilities in subsection 11.2(5) of the Regulation 14.15

139.7 Total Provision for Adverse Deviation (%) 7.00 %

139.8 Amount of Provision for Adverse Deviation included normal cost (line **9**, **10** and **10a**) 7,697,917.00

139.9. a) Does the plan provide future escalated adjustments? ☑ Yes ☐ No

If **139.9(a)** is **yes,**

b) Are the future costs of escalated adjustments included in the calculation of the Provision for Adverse Deviation amounts on lines **064c** and **139.8**? ☐ Yes ☑ No

If **139.9(b)** is **no,**

c) Enter the going-concern liability related to the future escalated adjustments ,140,661,895

d) Enter the normal cost related t o the future escalated adjustments 26,638,753

Solvency valuation

140.1 If line **137** is **yes**,

a) Enter the total asset value of the buy-in annuities as reported in the actuarial valuation report .....

b) Enter the total liabilities related to the buy-in annuities as reported in the actuarial valuation report .....

c) Enter the total asset value of the non-discharged buy-out annuities as reported in the actuarial valuation report .....

d) Enter the total liabilities related to the non-discharged buy-out annuities as reported in the actuarial valuation report .....

e) If line **138(e)** is **yes**,
i) Enter the solvency liabilities related to the discharge at the time of purchase.....

140.2. Enter the total value of any reduced solvency deficiency payments (or solvency deficiency payments if applicable) that are guaranteed by letter(s) of credit.....

140.3 Enter the expiry date of the letter of credit, if any ..... Year Month Day

140.4 Solvency asset adjustment 10,714,000

140.5 Solvency liability adjustment..... -635,692,354

140.6 Reduced solvency deficiency..... 0

140.7 Solvency ratio as per the Regulation (express in decimal format) 1.3400

140.8 Components of the solvency special payments on lines **013** and **013a**

Special payments with respect to reduced solvency deficiency	Period 1	Period 2	Period 3	Period 4	Present value of the special payments on the solvency basis
140.8a Members	0	0	0		0
140.8b Employer	0	0	0		0

141. Have any of the excludable benefits been excluded?..... ☑ Yes ☐ No ☐ N/A

142. If line **141** is **yes**, enter the total amount of liabilities being excluded 2,799,876,100

144. (i) Has an averaging method been applied to the market value of assets in determining the solvency asset adjustment?..... ☑ Yes ☐ No

a) If **yes**, indicate the positive or negative amount by which the solvency assets are adjusted as a result of applying the averaging method..... 10,714,000

(ii) Has the averaging method used in determining the solvency asset adjustment changed since the last valuation? ☐ Yes ☑ No

If **yes**, complete **(ii)a** or **(ii)b**, as appropriate:

a) The change in method increases the solvency asset adjustment by the amount of.....

b) The change in method decreases the solvency asset adjustment by the amount of .....

P. Miscellaneous

145. Prior year credit balance..... 20,700,000

146. Transfer ratio (express in decimal format)..... 0.9500

Guarantee fund assessment

147. PBGF liabilities 6,953,284,709

148. PBGF assessment base..... 0

149. Amount of additional liability for plant closure and/or permanent layoff benefits as described in E of subsection 37(4) of the Regulation 0

149a. Number of Ontario plan beneficiaries..... 14,986

Part IV – Information required by the Canada Revenue Agency

R. Additional information

173. Surplus/deficit determined at the valuation date as per the instructions:

173a. Going-concern basis	2,134,465,641
173b. Wind-up basis	-429,201,809
173c. For designated plans, maximum funding valuation basis	0

174. Excess surplus determined at the valuation date:

174a. Going-concern basis	0
174b. For designated plans, maximum funding valuation basis	

175. For designated plans, employer normal cost determined under the maximum funding valuation basis:

Period 1	
Period 2	
Period 3	
Period 4	

176. Minimum surplus required under applicable pension benefit legislation before contribution holiday:

176a. Going-concern basis	0
176b. Wind-up basis	0

177. Maximum amount that could be claimed as eligible employer contribution(s) – defined benefit provisions – under subsection 147.2(2) of the Income Tax Act:

177a. Unfunded liability	429,201,809
177b. Normal cost:	
Period 1	65,969,770
Period 2	66,890,796
Period 3	69,212,249
Period 4	

178. Do you have any employees contributing over the limit stipulated under paragraph 8503(4) of the Income Tax Regulations? ☑ Yes ☐ No

Part V – Information required by Retraite Québec

S. Additional Information

185. Date on which the valuation report was prepared ..... _____

186. Value of additional liabilities arising from an improvement on a funding basis ..... _____

187. Value of additional liabilities arising from an improvement on a solvency basis ..... _____

188. Surplus assets that can be allocated to fund contributions ..... _____

189. Special payments..... _____

190. Total of the letters of credit taken into account in the assets on a funding basis..... _____

191. Insured annuities from an insurer taken into account in the actuarial valuation on a solvency basis..... _____

T. Additional information for plans whose employer is a municipality, a municipal housing bureau, or an educational institution at the university level

For service prior to the establishment of the stabilization fund

192. Reserve on a funding basis ..... _____

	Present value	Amortization payments			
		Period 1	Period 2	Period 3	Period 4
193. Deficiency attributable to the employer					
194. Funding deficiency **194a.** Payable by the members					
194b. Payable by the employer					

For service following the establishment of the stabilization fund

195. Stabilization fund value ..... _____

	Stabilization contributions			
	Period 1	Period 2	Period 3	Period 4
196. Members				
197. Employer				

	Present value	Amortization payments			
		Period 1	Period 2	Period 3	Period 4
198. Technical funding deficiency **198a.** Payable by the members					
198b. Payable by the employer					

U. Additional information for pension plans other than those mentioned in Section T, and for which solvency funding does not apply.

199. Target level (as a percentage) of the required stabilization provision ..... _____

	Current service stabilization contributions			
	Period 1	**Period 2**	**Period 3**	**Period 4**
200. Members				
201. Employer				

	Present Value	**Amortization payments**			
		Period 1	**Period 2**	**Period 3**	**Period 4**
202. Technical funding deficiency **202a.** Payable by the members					
202b. Payable by the employer					
203. Stabilization funding deficiency **203a.** Payable by the members					
203b. Payable by the employer					
204. Improvement funding deficiency **204a.** Payable by the members					
204b. Payable by the employer					

Part VI – Certification by Actuary

As the actuary who signed the funding valuation report (the report), I certify that this completed form accurately reflects the information provided in the report.

Dated this 23 (day) day of September (month), 2025 (year)

Suzanne Jacques

Signature of actuary

Suzanne Jacques

Print or type name of actuary

Towers Watson Canada Inc.

Name of firm

(416)960-7460

Telephone

suzanne.jacques@wtwco.com

Email*

*** Optional information. The Canada Revenue Agency will not communicate on plan specific matters with clients by email, since we cannot guarantee the confidentiality of emailed information.**

Personal information is collected under the authority of section 147.2 of the Income Tax Act and is used for the administration of a registered pension plan. It may also be used for any purpose related to the administration or enforcement of the Act such as audit and compliance. Information may also be shared or verified under information-sharing agreements to the extent authorized by law. Under the Privacy Act, individuals have the right to access their personal information and request correction if there are errors or omissions. Refer to Info Source **canada.ca/cra-info-source**, Personal Information Bank CRA PPU 226.

March 13, 2026

Ms. Dorothy Quinn
Senior Manager, Finance Business Services
Hydro One Inc.
483 Bay Street, South Tower
Toronto, Ontario M5G 2P5

Dear Dorothy:

HYDRO ONE INC. ("HYDRO ONE") PROJECTED 2026 – 2032 BENEFIT COST UNDER FASB ASC 715-20-50

As requested, we have prepared the projected benefit cost for 2026 to 2032 under FASB Accounting Standards Codification Topic 715-20-50 ("US GAAP") for the following pension and benefits plans sponsored by Hydro One.

- Hydro One Pension Plan (the "RPP");
- Hydro One Defined Contribution Plan (the "DCPP");
- Hydro One Supplementary Pension Plan (the "SPS/DSPS");
- Hydro One Supplemental Defined Contribution Plan (the "Notional DCPP");
- Hydro One Non-Pension Post Retirement Benefits (the "Hydro One PRB"); and
- Hydro One Post-Employment Benefits (the "PEB").

It is intended that this letter is read in conjunction with our December 31, 2025 year-end disclosure reports (the "2025 Year-end Reports") for all benefit plans listed above.

130 King Street West
Suite 1500
Toronto, Ontario
M5X 1E3

T +1 416 960.2700
W wtwco.com

Towers Watson Canada Inc.

Key Results - Projected Benefit Cost ($millions)

Based on the assumptions and approaches set out later in this letter, the projected benefit cost for the various arrangements are as follows:

	2026	2027	2028	2029	2030	2031	2032
RPP	$(78.0)	$(65.9)	$(72.4)	$(81.7)	$(94.3)	$(103.4)	$(119.0)
SPS/DSPS	$7.7	$8.5	$8.5	$8.4	$8.3	$8.3	$8.2
DCPP	$5.4	$5.9	$7.0	$7.6	$8.1	$8.7	$9.3
Notional DCPP	$0.8	$0.9	$1.0	$1.1	$1.2	$1.4	$1.5
Hydro One PRB	$117.1	$123.1	$129.7	$136.6	$143.1	$151.1	$159.1
PEB	$26.0	$28.2	$29.7	$31.8	$33.6	$35.1	$36.6
Total	**$79.0**	**$100.7**	**$103.5**	**$103.8**	**$100.0**	**$101.2**	**$95.7**

Detailed schedules providing the development of the benefit cost by year for each plan, other than for the DCPP, can be found in the enclosed Appendices. As requested, we have also included the allocation of projected benefit costs to the active and inactive members of the plans (other than for the DCPP and Notional DCPP). Appendices A and B provide projection details as follows:

- Appendix A – Projections for RPP, SPS/DSPS and Notional DCPP; and
- Appendix B – Projections for Hydro One PRB and PEB.

Discount Rate Sensitivity – Projected Benefit Cost ($millions)

The projected benefit cost each year as a result of a 0.5% decrease in the accounting discount rates for the projection period are as follows (no other assumptions are assumed to change):

	2026	2027	2028	2029	2030	2031	2032
RPP	$(78.0)	$17.9	$10.5	$0.1	$(14.2)	$(22.1)	$(39.7)
SPS/DSPS	$7.7	$9.0	$8.9	$8.8	$8.6	$8.6	$8.5
DCPP	$5.4	$5.9	$7.0	$7.6	$8.1	$8.7	$9.3
Notional DCPP	$0.8	$0.9	$1.0	$1.1	$1.2	$1.4	$1.5
Hydro One PRB	$117.1	$141.6	$148.5	$155.6	$162.2	$169.8	$177.2
PEB	$31.3	$28.4	$29.9	$32.0	$33.8	$35.3	$36.8
Total	**$84.3**	**$203.7**	**$205.8**	**$205.2**	**$199.7**	**$201.7**	**$193.6**

Assumptions

All assumptions are the same as those disclosed in the 2025 Year-end Reports, except for the new entrant assumptions disclosed in this letter and the rate of salary increase assumption which has been updated for the projection period 2026 to 2032. A summary of the assumptions can be found in Appendix C.

Membership Data

Summaries of data upon which these projections were based can be found in the following documents:

RPP:	Hydro One Pension Plan actuarial valuation report as at December 31, 2024 dated August 2025 (the "Funding Report");
SPS/DSPS:	Hydro One Supplementary Pension Plan December 31, 2024 actuarial report dated September 2025 (the "LOC Report");
Hydro One PRB and PEB:	Hydro One Non-Pension Post-Retirement Benefits Plan, Post-Employment Benefits Plan and Hydro One Supplementary Pension Plan Actuarial Valuation Report Disclosure for Fiscal Year Ending December 31, 2025 (the "2025 PRB/PEB/SERP Year-End Report").

In addition, information regarding new entrant assumptions can be found under the Methodology section of this letter.

Plan Provisions

Summaries of the provisions for the different pension plans other than the DCPP and Notional DCPP, can be found in the Funding Report and the LOC Report.

A summary of the provisions of the Hydro One PRB plan can be found in the valuation report, *"Post-Retirement Benefits Plans: Actuarial Valuation Results as of January 1, 2023"* dated January 2024.

Further details on the provisions of the PEB plan can be found in the valuation report, *"Hydro One Long-Term Disability Benefits Plan Valuation as of December 31, 2025"* dated January 2026.

DCPP

For Management employees hired on or after September 30, 2015, they are no longer entitled to the DB plan and they accrue benefits on a Defined Contribution (DC) basis. Members may elect to contribute 4%, 5% or 6% of pensionable earnings. Hydro One matches 100% of member contributions. The estimated annual pension expense for the DCPP is equal to the estimated annual contributions to the plan based on the profile of existing and new management employees (see Methodology section below) and assuming all members contribute 6% of pensionable earnings.

It was assumed that members of the DCPP will continue to be eligible for the Hydro One PRB Plan, with the provisions in place as of the date of this letter.

Notional DCPP

The Notional DCPP provides for Hydro One contributions in excess of the Income Tax Act limit for members who participate in the DCPP. These notional contributions are allocated to the respective members and they accrue with deemed investment returns on a periodic basis. The CEO and EVP level executives receive a notional contribution equal to 15% of pensionable earnings less the Hydro One DCPP contribution. All other members receive a notional contribution under the same terms as the DCPP, less the Hydro One DCPP contribution.

Methodology

Funding Contributions - RPP

Hydro One funding contributions for 2026 - 2032 are assumed to be equal to the estimated normal cost extrapolated from the results in the Funding Report with the following adjustments to the assumptions:

- a going concern discount rate of 6.9% p.a.;
- the salary scale used in 2025 Year-end Reports and the salary scale shown herein (for 2027 onwards); and
- expected future new entrants described in this letter.

As directed by Hydro One, the existing $20.7 million prior year credit balance is not applied during the projection period and no future contribution holiday should be considered (note that a contribution holiday is not currently permitted given the funded status of the plan).

Currently, no special funding payments are required for the RPP; we have assumed that no special funding payments would be required over the projection period. It is important to note that the minimum required contributions following the next filed actuarial valuation may be significantly different due to several factors, including experience gains and losses and future changes to liability measurement assumptions.

Assets

The market value of assets as at December 31, 2025 for the RPP was provided by Hydro One on January 9, 2026. The estimated market value of assets over the projection period has been extrapolated from the market value of assets as at December 31, 2025. The extrapolations are based on estimated contributions, benefit payments in the intervening period and a return on assets assumption of 7.20% per annum.

As instructed by Hydro One, the estimated member contributions to be made to the RPP during the projection period are in accordance with the rates outlined under the plan provisions section of the Funding Report.

Consistent with Hydro One's actual disclosures at December 31, 2025, we have included the value of the Refundable Tax Account balance for the SPS/DSPS in our calculations. On June 20, 2024, Bill C-59 received Royal Assent. As a result, fees paid for a letter of credit used to provide security for SERP benefits will no longer be considered contributions to an RCA, and therefore RCA refundable tax will no longer be payable on such fees. Due to this change, no expected letter of credit fee is included in the expense calculations over the projection period. Additionally, the historical fees remitted to the CRA in respect of letters of credit can be recovered by employers starting in 2025. Hydro One applied to CRA to recover these fees and a refund of $2,976,000 was received in 2025 in respect of historical letter of credit fees. The remaining refund has been reflected as a refund of employer contributions in 2026.

Hydro One PRB, PEB and DC Notional plans are not funded and have no assets.

Benefit Obligations and Service Cost

The projected benefit obligations and service cost over the period (December 31, 2025 to December 31, 2032) for the RPP and SPS/DSPS have been estimated based on the most recent membership data as set out in the Funding Report and LOC Report respectively, projected to each December 31 using the assumptions set out in this letter. For PRB and PEB, the projected benefit obligations

and service cost have been estimated based on the most recent membership data as set out in the 2025 PRB/PEB/SERP Year-End Report, with the adjustments which have been outlined in this letter. In addition, it was assumed that some active members terminating or retiring would be replaced by new entrants.

The projected benefit obligation for the DCPP is $0 at any point in time. The service cost over the projection period was determined based on the level of actual 2025 Hydro One contributions adjusted to reflect expected salary increases and new entrants.

The projected benefit obligation and service cost for the Notional DCPP over the period (December 31, 2025 to December 31, 2032) has been estimated based on actual aggregate Notional DCPP account balance as of December 31, 2025, a 7.20% p.a. rate of return, estimated earnings and benefit payments over the projection period.

As directed by Hydro One, we have assumed the following with respect to new entrants:

For the RPP:

	Percentage of New Entrants in Category	Average Age	Average Earnings
Power Workers Union Members	42%	35	$101,000
Society Members	58%	34	$113,000
Management Members	0%	N/A	N/A

As instructed by Hydro One, the RPP active membership in aggregate, is assumed to change at the following rates:

	2026	2027	2028	2029	2030	2031	2032
Population Change %	4.5%	1.4%	3.1%	1.9%	0.5%	0.2%	-0.1%

For the DCPP:

For each year commencing January 1, 2026, new Management members are assumed to be hired externally and assumed to replace exiting DB Management employees.

As instructed by Hydro One, the DCPP active membership in aggregate, is assumed to increase at the following rates:

	2026	2027	2028	2029	2030	2031	2032
Population Change %	25.4%	2.8%	13.2%	4.2%	2.2%	2.0%	2.0%

For the Notional DCPP

No new entrants are assumed over the projection period.

For the SPS/DSPS:

The projected benefit obligations and service cost over the projection period for the SPS/DSPS have been estimated based on the most recent membership data as set out in the LOC Report, projected using the demographic assumptions set out 2025 Year-end Reports.

For the PRB plan:

	Percentage of New Entrants in Category	Average Age	Average Earnings
Power Workers Union Members	69%	34	$91,000
Society Members	15%	36	$104,000
Management Members	16%	39	$116,000

These new entrant profiles were developed using the new entrant membership data from the most recent valuation.

For the Hydro One PRB plan and the PEB, the active membership in aggregate, is assumed to change at the following rates:

	2026	2027	2028	2029	2030	2031	2032
Population Change %	5.6%	1.6%	4.0%	2.1%	0.7%	0.4%	0.1%

The active membership projection of the Hydro One PRB plan and the PEB reflects the open nature of the plans to all employee groups.

Except as noted above, please refer to the 2025 Year-end Reports for additional details on methodology and accounting policies.

Allocation of Benefit Cost

Active and Inactive Split

As instructed by Hydro One, the projected benefit cost over the projection period is allocated to the active and inactive members of the plans as follows:

Current Service Cost	Allocated to active members
Interest Cost and EROA	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Amortization of net actuarial (gains)/losses	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Past service cost for RPP	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of the calendar year
Past service cost for SPS/DSPS	Allocated to active and inactive members on a pro-rata basis based on plan liabilities as at the beginning of that calendar year with the exception of certain past service costs for SPS/DSPS that are entirely in respect of former executives and are fully allocated to the inactive membership
Past service cost for the PRB plans	Allocated to active and inactive members on a pro-rata basis based on plan liabilities at the time of the transfer event for the CSO Transfer (refer to the *Hydro One Non-Pension Post-Retirement Benefits Plan, Post-Employment Benefits Plan and Hydro One Supplementary Pension Plan Actuarial Valuation Report Disclosure for Fiscal Year Ending December 31, 2023* for additional details on this transfer event) Entirely allocated to active members for the ITO Transfer, the S2P Transfer and the F&A Pay and Shared Services Transfer (refer to the *Hydro One Non-Pension Post-Retirement Benefits Plan, Post-Employment Benefits Plan and Hydro One Supplementary Pension Plan Actuarial Valuation Report Disclosure for Fiscal Year Ending December 31, 2023* for additional details on these transfer events) Entirely allocated to inactive members for the Inergi OPEB Retirees and Other Former Members Transfer (refer to the 2023 PRB/PEB/SERP Year-End Report for additional details on this transfer event)

Notes Concerning our Calculations

There are a number of factors not reflected in this report that could potentially result in the benefit costs being different than expected including, but not limited to, changes to pension or benefit plan provisions other than those mentioned in this letter, experience revealed in any new valuation of the plans, contributions to the pension fund significantly different than expected, any significant event such as material downsizing or acquisition/divestiture, change in accounting standards or additional changes to the assumptions or methodology.

Actuarial Certification

The calculations herein have been made in accordance with US GAAP with which we are familiar. The assumptions used were selected by Hydro One management for the purpose of preparing this letter, following discussions with WTW, and they are in accordance with accepted actuarial practice. In our opinion, the data on which the calculations are based are sufficient and reliable for the purpose of these estimates. This letter and attachments have been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

The results presented in this letter have been developed using a particular set of actuarial assumptions and methods. Other results could have been developed by selecting different actuarial assumptions and methods. The results presented in this letter are reasonable actuarial results based on actuarial assumptions reflecting our expectation of future events. The actual benefit cost levels will change in the future as a result of future changes in the actuarial methods and assumptions, the membership data, the plan provisions and the legislative rules, or as a result of future experience gains or losses, none of which has been anticipated at this time. Emerging experience, differing from the assumptions, will result in gains or losses that will be revealed in future accounting valuations.

On March 11, 2026, the Canadian Institute of Actuaries (CIA) released a new Canadian pensioners' mortality research report, with guidance materials to follow shortly. The research provides an updated set of mortality tables that reflect the mortality rates of Canadian retirees and surviving spouses as of January 1, 2024. This research, along with the CIA's April 11, 2024 research paper on mortality improvements, may inform the reporting of Canadian pension plans. The effect of the research has not been reflected in the results shown. Pending additional guidance issued by the CIA and analysis to assess the applicability of the research findings for the plan, changes, if any, will be made to mortality assumptions in future results.

As at the date of this letter, other than mentioned above, we are not aware of any subsequent events that would have a material impact on the results of the projected benefit cost.

The information contained in this letter was prepared for Hydro One, for its internal budgeting purposes. It is not intended for and may not be used for other purposes, and we accept no responsibility or liability in this regard.

The undersigned consultants with actuarial credentials meet the Qualification Standards of the American Academy of Actuaries to render the actuarial opinions contained herein. Our objectivity is not impaired by any relationship between the plan sponsor and our employer, Towers Watson Canada Inc.

Should you have any questions, please do not hesitate to contact us.

TOWERS WATSON CANADA INC.

In respect of the pension plans:

Suzanne Jacques, FCIA, FSA

Davis Gonsalves, FCIA, FSA

In respect of the post-retirement and post-employment plans:

Donald Luciak, FCIA, FSA

Melissa Shi, FCIA, FSA

Enclosures

cc: Carolyn Tsen, Sean Stenning, Angela Suh — Hydro One Inc.
Rina Xu, Esther Lam — WTW

Hydro One Pension Plan
Projected 2026 to 2032 Accounting Under US GAAP

APPENDIX A.1

Figures in $000s

		Projections						
		2026	2027	2028	2029	2030	2031	2032
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	8,906,701	9,275,779	9,565,463	9,881,038	10,221,408	10,584,179	10,969,431
	Employer service cost (BOY)	149,849	164,245	174,693	183,760	191,063	198,254	205,100
	Interest cost	448,188	467,586	482,819	499,243	516,758	535,366	555,041
	Actuarial(gains)/losses	112,906	-	-	-	-	-	-
	Plan Participants' contributions	84,848	91,029	97,424	103,209	108,087	112,834	117,217
	Benefits Paid	(426,713)	(433,176)	(439,361)	(445,842)	(453,137)	(461,202)	(470,307)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	PBO at current fiscal year end	9,275,779	9,565,463	9,881,038	10,221,408	10,584,179	10,969,431	11,376,482
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	9,500,832	9,900,955	10,337,460	10,810,751	11,322,233	11,872,392	12,463,213
	Expected return on plan assets	674,193	703,265	734,880	769,100	805,991	845,639	888,165
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	67,795	75,387	80,348	85,015	89,218	93,550	97,909
	Plan Participants' contributions	84,848	91,029	97,424	103,209	108,087	112,834	117,217
	Benefits paid	(426,713)	(433,176)	(439,361)	(445,842)	(453,137)	(461,202)	(470,307)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	9,900,955	10,337,460	10,810,751	11,322,233	11,872,392	12,463,213	13,096,197
C	**Amount recognized in the balance sheet**							
	Present value of obligations	9,275,779	9,565,463	9,881,038	10,221,408	10,584,179	10,969,431	11,376,482
	Fair value of plan assets	9,900,955	10,337,460	10,810,751	11,322,233	11,872,392	12,463,213	13,096,197
	Surplus (deficit)	625,176	771,997	929,713	1,100,825	1,288,213	1,493,782	1,719,715
	Unrecognized past service cost (benefit)	(8,708)	(5,458)	(2,208)	1,042	4,292	2,816	399
	Unrecognized net actuarial (gains)/losses	132,105	123,298	115,078	107,406	100,246	93,086	86,437
	Cumulative employer contributions in excess of benefit cost	748,573	889,837	1,042,583	1,209,273	1,392,751	1,589,684	1,806,551
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	(112,906)	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	(112,906)	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(1,371)	(8,807)	(8,220)	(7,672)	(7,160)	(7,160)	(6,649)
	- Past service credits/(costs) amortized in year	3,250	3,250	3,250	3,250	3,250	(1,476)	(2,417)
	Sub-total	1,879	(5,557)	(4,970)	(4,422)	(3,910)	(8,636)	(9,066)
	Credit (charge) to OCI in year	(114,785)	5,557	4,970	4,422	3,910	8,636	9,066
D	**Components of Benefit Cost**							
	Employer service cost	149,849	164,245	174,693	183,760	191,063	198,254	205,100
	Interest cost	448,188	467,586	482,819	499,243	516,758	535,366	555,041
	Expected return on plan assets	(674,193)	(703,265)	(734,880)	(769,100)	(805,991)	(845,639)	(888,165)
	Net prior service (credit)/cost amortization	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	1,476	2,417
	Net (gains)/loss amortization	1,371	8,807	8,220	7,672	7,160	7,160	6,649
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	(78,035)	(65,877)	(72,398)	(81,675)	(94,260)	(103,383)	(118,958)
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	20,570	132,105	123,298	115,078	107,406	100,246	93,086
	EARSL	15.00	15.00	15.00	15.00	15.00	14.00	14.00
	Amortization of (gains)/losses	1,371	8,807	8,220	7,672	7,160	7,160	6,649
	Prior service (credit)/cost	(11,958)	(8,708)	(5,458)	(2,208)	1,042	4,292	2,816
	Amortization of prior service (credit)/cost	(3,250)	(3,250)	(3,250)	(3,250)	(3,250)	1,476	2,417
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	602,743	748,573	889,837	1,042,583	1,209,273	1,392,751	1,589,684
	Pension expense recognized in P&L in the financial year	78,035	65,877	72,398	81,675	94,260	103,383	118,958
	Employer contributions made in the financial year	67,795	75,387	80,348	85,015	89,218	93,550	97,909
	Benefits paid directly by company in the financial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	748,573	889,837	1,042,583	1,209,273	1,392,751	1,589,684	1,806,551
G	**Assumptions**							
	At beginning of period							
	Discount rate	5.02%	5.02%	5.02%	5.02%	5.02%	5.02%	5.02%
	Expected rate of return on plan assets	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%

Hydro One Inc. Supplementary Pension Plan
Projected 2026 to 2032 Accounting Under US GAAP

APPENDIX A.2

Figures in $000s

		Projections						
		2026	2027	2028	2029	2030	2031	2032
A	**Change in Benefit Obligation**							
	PBO at prior fiscal year end	124,951	130,336	130,728	130,941	130,989	130,868	130,581
	Employer service cost	525	787	800	808	807	807	799
	Interest cost	6,133	6,412	6,427	6,433	6,431	6,421	6,402
	Actuarial(gains)/losses	5,346	-	-	-	-	-	-
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the Company	(6,619)	(6,807)	(7,014)	(7,193)	(7,359)	(7,515)	(7,695)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Expenses paid	-	-	-	-	-	-	-
	Plan change	-	-	-	-	-	-	-
	Acquisitions/divestitures	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Benefit obligation - end of period	130,336	130,728	130,941	130,989	130,868	130,581	130,087
B	**Change in Plan Assets**							
	Fair value of assets at prior fiscal year end	2,893	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions - benefits paid	6,619	6,807	7,014	7,193	7,359	7,515	7,695
	Employer contributions - Letter of credit	(2,893)	-	-	-	-	-	-
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits paid from the company	(6,619)	(6,807)	(7,014)	(7,193)	(7,359)	(7,515)	(7,695)
	Transfer payments	-	-	-	-	-	-	-
	Taxes paid	-	-	-	-	-	-	-
	Acquisitions/divestitures	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Market value of plan assets - end of period	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	130,336	130,728	130,941	130,989	130,868	130,581	130,087
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit)	(130,336)	(130,728)	(130,941)	(130,989)	(130,868)	(130,581)	(130,087)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	20,083	18,744	17,494	16,328	15,239	14,150	13,139
	Cumulative employer contributions in excess of benefit cost	(110,253)	(111,984)	(113,447)	(114,661)	(115,629)	(116,431)	(116,948)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	(5,346)	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	(5,346)	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(1,053)	(1,339)	(1,250)	(1,166)	(1,089)	(1,089)	(1,011)
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(1,053)	(1,339)	(1,250)	(1,166)	(1,089)	(1,089)	(1,011)
	Credit (charge) to OCI in year	(4,293)	1,339	1,250	1,166	1,089	1,089	1,011
D	**Components of Benefit cost**							
	Employer service cost	525	787	800	808	807	807	799
	Expected letter of credit fee	-	-	-	-	-	-	-
	Interest cost	6,133	6,412	6,427	6,433	6,431	6,421	6,402
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service cost amortization	-	-	-	-	-	-	-
	Net loss/(gain) amortization	1,053	1,339	1,250	1,166	1,089	1,089	1,011
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	7,711	8,538	8,477	8,407	8,327	8,317	8,212
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	15,790	20,083	18,744	17,494	16,328	15,239	14,150
	EARSL	15.00	15.00	15.00	15.00	15.00	14.00	14.00
	Amortization of (gains)/losses	1,053	1,339	1,250	1,166	1,089	1,089	1,011
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(106,268)	(110,253)	(111,984)	(113,447)	(114,661)	(115,629)	(116,431)
	Pension expense recognized in P&L in the financial year	(7,711)	(8,538)	(8,477)	(8,407)	(8,327)	(8,317)	(8,212)
	Employer contributions made in the financial year	(2,893)	-	-	-	-	-	-
	Benefits paid directly by company in the financial year	6,619	6,807	7,014	7,193	7,359	7,515	7,695
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(110,253)	(111,984)	(113,447)	(114,661)	(115,629)	(116,431)	(116,948)
G	**Assumptions**							
	At beginning of period							
	Discount rate	5.02%	5.02%	5.02%	5.02%	5.02%	5.02%	5.02%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Pension Plan (RPP) and Hydro One Inc. Supplementary Pension Plan (SPS/DSPS) **APPENDIX A.3**

Projected 2026 to 2032 Accounting Under US GAAP

Active / Inactive Split

Figures in $000s

RPP

Components of Benefit Cost	2026 Inactive	2026 Active	2026 Total	2027 Inactive	2027 Active	2027 Total	2028 Inactive	2028 Active	2028 Total	2029 Inactive	2029 Active	2029 Total	2030 Inactive	2030 Active	2030 Total	2031 Inactive	2031 Active	2031 Total	2032 Inactive	2032 Active	2032 Total
Current service cost	0	149,849	149,849	0	164,245	164,245	0	174,693	174,693	0	183,760	183,760	0	191,063	191,063	0	198,254	198,254	0	205,100	205,100
Interest cost	293,563	154,625	448,188	300,658	166,928	467,586	304,176	178,643	482,819	307,534	191,709	499,243	311,605	205,153	516,758	316,401	218,965	535,366	321,369	233,672	555,041
Expected return on plan assets	(441,596)	(232,597)	(674,193)	(452,199)	(251,066)	(703,265)	(462,974)	(271,906)	(734,880)	(473,766)	(295,334)	(769,100)	(486,013)	(319,978)	(805,991)	(499,773)	(345,866)	(845,639)	(514,248)	(373,917)	(888,165)
Amortization of past service cost	(2,531)	(719)	(3,250)	(2,589)	(661)	(3,250)	(2,826)	(424)	(3,250)	(3,057)	(193)	(3,250)	(3,057)	(193)	(3,250)	793	683	1,476	1,560	857	2,417
Amortization of net (gain) loss	898	473	1,371	5,663	3,144	8,807	5,179	3,041	8,220	4,726	2,946	7,672	4,317	2,843	7,160	4,232	2,928	7,160	3,850	2,799	6,649
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Settlement (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	(149,666)	71,631	(78,035)	(148,467)	82,590	(65,877)	(156,445)	84,047	(72,398)	(164,563)	82,888	(81,675)	(173,148)	78,888	(94,260)	(178,347)	74,964	(103,383)	(187,469)	68,511	(118,958)
Credit (charge) to OCI in year	(1,633)	(246)	(1,879)	3,074	2,483	5,557	2,353	2,617	4,970	1,669	2,753	4,422	1,260	2,650	3,910	5,025	3,611	8,636	5,410	3,656	9,066

SPS/DSPS

Components of Benefit Cost	2026 Inactive	2026 Active	2026 Total	2027 Inactive	2027 Active	2027 Total	2028 Inactive	2028 Active	2028 Total	2029 Inactive	2029 Active	2029 Total	2030 Inactive	2030 Active	2030 Total	2031 Inactive	2031 Active	2031 Total	2032 Inactive	2032 Active	2032 Total
Current service cost	0	525	525	0	787	787	0	800	800	0	808	808	0	807	807	0	807	807	0	799	799
Expected letter of credit fee	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Interest cost	5,225	908	6,133	5,437	975	6,412	5,444	983	6,427	5,455	978	6,433	5,447	984	6,431	5,432	989	6,421	5,397	1,005	6,402
Expected return on plan assets	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of past service cost	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Amortization of net (gain) loss	897	156	1,053	1,135	204	1,339	1,059	191	1,250	989	177	1,166	922	167	1,089	921	168	1,089	852	159	1,011
Curtailment (gain) / loss recognized	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Special Termination Benefit	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total benefit cost recognized in the P&L account	6,122	1,589	7,711	6,572	1,966	8,538	6,503	1,974	8,477	6,444	1,963	8,407	6,369	1,958	8,327	6,353	1,964	8,317	6,249	1,963	8,212
Credit (charge) to OCI in year	897	156	1,053	1,135	204	1,339	1,059	191	1,250	989	177	1,166	922	167	1,089	921	168	1,089	852	159	1,011

Hydro One Supplemental Defined Contribution Plan
Projected 2026 to 2032 Accounting Under US GAAP

APPENDIX A.4

Figures in $000s

		Projections						
		2026	2027	2028	2029	2030	2031	2032
A	**Change in Benefit Obligation**							
	PBO at prior fiscal year end	1,340	2,058	2,860	3,721	4,643	5,631	6,688
	Employer service cost	667	734	775	818	863	911	961
	Interest cost	118	171	229	291	357	428	504
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the Company	(67)	(103)	(143)	(186)	(232)	(282)	(334)
	Transfer from (to) other plans	-	-	-	-	-	-	-
	Expenses paid	-	-	-	-	-	-	-
	Plan change	-	-	-	-	-	-	-
	Acquisitions/divestitures	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Benefit obligation - end of period	2,058	2,860	3,721	4,643	5,631	6,688	7,820
B	**Change in Plan Assets**							
	Fair value of assets at prior fiscal year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions - benefits paid	67	103	143	186	232	282	334
	Plan participants' contributions	-	-	-	-	-	-	-
	Benefits Paid from the company	(67)	(103)	(143)	(186)	(232)	(282)	(334)
	Transfer payments	-	-	-	-	-	-	-
	Taxes paid	-	-	-	-	-	-	-
	Acquisitions/divestitures	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Market value of plan assets - end of period	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	2,058	2,860	3,721	4,643	5,631	6,688	7,820
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit)	(2,058)	(2,860)	(3,721)	(4,643)	(5,631)	(6,688)	(7,820)
	Unrecognized past service cost (benefit)	-	-	-	-	-	-	-
	Unrecognized net actuarial (gains)/losses	245	229	214	200	187	174	162
	Cumulative employer contributions in excess of benefit cost	(1,813)	(2,631)	(3,507)	(4,443)	(5,444)	(6,514)	(7,658)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	-	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	Sub-total	-	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	(17)	(16)	(15)	(14)	(13)	(13)	(12)
	- Past service credits/(costs) amortized in year	-	-	-	-	-	-	-
	Sub-total	(17)	(16)	(15)	(14)	(13)	(13)	(12)
	Credit (charge) to OCI in year	17	16	15	14	13	13	12
D	**Components of Benefit cost**							
	Employer service cost	667	734	775	818	863	911	961
	Interest cost	118	171	229	291	357	428	504
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service cost amortization	-	-	-	-	-	-	-
	Net loss/(gain) amortization	17	16	15	14	13	13	12
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	802	921	1,019	1,123	1,233	1,352	1,477
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	262	245	229	214	200	187	174
	EARSL	15	15	15	15	15	14	14
	Amortization of (gains)/losses	17	16	15	14	13	13	12
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(1,078)	(1,813)	(2,631)	(3,507)	(4,443)	(5,444)	(6,514)
	Pension expense recognized in P&L in the financial year	(802)	(921)	(1,019)	(1,123)	(1,233)	(1,352)	(1,477)
	Employer contributions made in the financial year	-	-	-	-	-	-	-
	Benefits paid directly by company in the financial year	67	103	143	186	232	282	334
	Net transfer in/(out) (including the effect of any acquisitions/divestitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(1,813)	(2,631)	(3,507)	(4,443)	(5,444)	(6,514)	(7,658)
G	**Assumptions**							
	At beginning of period							
	Discount rate	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Expected rate of return on plan assets	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%	7.20%

Hydro One Limited Non-Pension Post Retirement Benefit
Projected 2026 to 2032 Accounting under US GAAP

APPENDIX B.1

Figures in $000s

		Projections						
		2026	2027	2028	2029	2030	2031	2032
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	1,476,206	1,545,244	1,616,911	1,694,966	1,778,992	1,868,472	1,963,425
	Employer service cost (BOY)	44,758	47,773	52,307	56,121	59,255	62,081	64,509
	Interest cost	75,463	79,055	82,854	86,939	91,290	95,901	100,765
	Actuarial(gains)/losses	2,099	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(53,282)	(55,161)	(57,106)	(59,034)	(61,065)	(63,029)	(65,175)
	Plan change	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	PBO at current fiscal year end	1,545,244	1,616,911	1,694,966	1,778,992	1,868,472	1,963,425	2,063,524
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	53,282	55,161	57,106	59,034	61,065	63,029	65,175
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(53,282)	(55,161)	(57,106)	(59,034)	(61,065)	(63,029)	(65,175)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	1,545,244	1,616,911	1,694,966	1,778,992	1,868,472	1,963,425	2,063,524
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(1,545,244)	(1,616,911)	(1,694,966)	(1,778,992)	(1,868,472)	(1,963,425)	(2,063,524)
	Unrecognized past service cost (benefit)	28,454	20,059	14,585	11,221	9,826	8,812	8,085
	Unrecognized net actuarial (gains)/losses	(351,783)	(339,681)	(328,761)	(318,930)	(310,060)	(302,162)	(295,246)
	Cumulative employer contributions in excess of benefit cost	(1,868,573)	(1,936,533)	(2,009,142)	(2,086,701)	(2,168,706)	(2,256,775)	(2,350,685)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	(2,099)	-	-	-	-	-	-
	- Past service credits/(costs) incurred in year	-	-	-	-	-	-	-
	- Transfers of gain/(loss) balance from other plans	-	-	-	-	-	-	-
	Sub-total	(2,099)	-	-	-	-	-	-
	LESS							
	- Net actuarial gains/(losses) amortized in year	13,394	12,102	10,920	9,831	8,870	7,898	6,916
	- Past service credits/(costs) amortized in year	(10,248)	(8,395)	(5,474)	(3,364)	(1,395)	(1,014)	(727)
	- Transfers of gain/(loss) balance to other plans	-	-	-	-	-	-	-
	Sub-total	3,146	3,707	5,446	6,467	7,475	6,884	6,189
	Credit (charge) to OCI in year	(5,245)	(3,707)	(5,446)	(6,467)	(7,475)	(6,884)	(6,189)
D	**Components of Benefit Cost**							
	Employer service cost	44,758	47,773	52,307	56,121	59,255	62,081	64,509
	Interest cost	75,463	79,055	82,854	86,939	91,290	95,901	100,765
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	10,248	8,395	5,474	3,364	1,395	1,014	727
	Net (gains)/loss amortization	(13,394)	(12,102)	(10,920)	(9,831)	(8,870)	(7,898)	(6,916)
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	Disclosed benefit cost	117,075	123,121	129,715	136,593	143,070	151,098	159,085
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	(367,276)	(351,783)	(339,681)	(328,761)	(318,930)	(310,060)	(302,162)
	EARSL	16.4	16.3	16.3	16.2	15.9	15.6	15.3
	Amortization of (gains)/losses	(13,394)	(12,102)	(10,920)	(9,831)	(8,870)	(7,898)	(6,916)
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(1,804,780)	(1,868,573)	(1,936,533)	(2,009,142)	(2,086,701)	(2,168,706)	(2,256,775)
	Benefit cost recognized in P&L in the financial year	(117,075)	(123,121)	(129,715)	(136,593)	(143,070)	(151,098)	(159,085)
	Employer contributions made in the financial year	53,282	55,161	57,106	59,034	61,065	63,029	65,175
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfers of obligation	-	-	-	-	-	-	-
	Net transfers of unamortized gain/loss balance	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(1,868,573)	(1,936,533)	(2,009,142)	(2,086,701)	(2,168,706)	(2,256,775)	(2,350,685)
G	**Assumptions**							
	At beginning of period							
	Discount rate	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Limited Post Employment Benefit
Projected 2026 to 2032 Accounting under US GAAP

APPENDIX B.2

Figures in $000s

		Projections						
		2026	2027	2028	2029	2030	2031	2032
A	**Change in Projected Benefit Obligation**							
	PBO at prior fiscal year end	149,061	156,916	165,516	174,815	184,843	195,641	207,248
	Employer service cost (BOY)	18,009	19,796	20,828	22,387	23,610	24,547	25,445
	Interest cost	7,979	8,428	8,895	9,409	9,952	10,527	11,142
	Actuarial(gains)/losses	-	-	-	-	-	-	-
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits Paid	(18,133)	(19,624)	(20,424)	(21,768)	(22,764)	(23,467)	(24,119)
	Plan change	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Net transfers	-	-	-	-	-	-	-
	PBO at current fiscal year end	156,916	165,516	174,815	184,843	195,641	207,248	219,716
B	**Change in Plan Assets**							
	Fair value of assets at prior year end	-	-	-	-	-	-	-
	Expected return on plan assets	-	-	-	-	-	-	-
	Actual gains/(losses) on assets	-	-	-	-	-	-	-
	Employer contributions	18,133	19,624	20,424	21,768	22,764	23,467	24,119
	Plan Participants' contributions	-	-	-	-	-	-	-
	Benefits paid	(18,133)	(19,624)	(20,424)	(21,768)	(22,764)	(23,467)	(24,119)
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Fair value of assets at current fiscal year end	-	-	-	-	-	-	-
C	**Amount recognized in the balance sheet**							
	Present value of obligations	156,916	165,516	174,815	184,843	195,641	207,248	219,716
	Fair value of plan assets	-	-	-	-	-	-	-
	Surplus (deficit) for funded plans	(156,916)	(165,516)	(174,815)	(184,843)	(195,641)	(207,248)	(219,716)
	Unrecognized past service cost (benefit)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Unrecognized net actuarial (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Cumulative employer contributions in excess of benefit cost	(156,916)	(165,516)	(174,815)	(184,843)	(195,641)	(207,248)	(219,716)
	Annual charges to OCI							
	- Net actuarial gains/(losses) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	- Past service credits/(costs) incurred in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	LESS	-	-	-	-	-	-	-
	- Net actuarial gains/(losses) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	- Past service credits/(costs) amortized in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Sub-total	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A
D	**Components of Benefit Cost**							
	Employer service cost	18,009	19,796	20,828	22,387	23,610	24,547	25,445
	Interest cost	7,979	8,428	8,895	9,409	9,952	10,527	11,142
	Expected return on plan assets	-	-	-	-	-	-	-
	Net prior service (credit)/cost amortization	-	-	-	-	-	-	-
	Net (gains)/loss amortization	-	-	-	-	-	-	-
	Curtailments	-	-	-	-	-	-	-
	Settlements	-	-	-	-	-	-	-
	Special/contractual termination benefits	-	-	-	-	-	-	-
	Disclosed benefit cost	25,988	28,224	29,723	31,796	33,562	35,074	36,587
E	**Gain/loss Amortization**							
	Cumulative (gains)/losses (BOY)	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	EARSL	N/A	N/A	N/A	N/A	N/A	N/A	N/A
	Amortization of (gains)/losses	N/A	N/A	N/A	N/A	N/A	N/A	N/A
F	**Reconciliation of accumulated contributions in excess of Benefit Cost**							
	Accumulated contributions in excess of Benefit Cost (BOY)	(149,061)	(156,916)	(165,516)	(174,815)	(184,843)	(195,641)	(207,248)
	Benefit cost recognized in P&L in the financial year	(25,988)	(28,224)	(29,723)	(31,796)	(33,562)	(35,074)	(36,587)
	Employer contributions made in the financial year	18,133	19,624	20,424	21,768	22,764	23,467	24,119
	Benefits paid directly by company in the fianncial year	-	-	-	-	-	-	-
	Net transfer in/(out) (including the effect of any acquisitions/diverstitures)	-	-	-	-	-	-	-
	Accumulated contributions in excess of Benefit Cost (EOY)	(156,916)	(165,516)	(174,815)	(184,843)	(195,641)	(207,248)	(219,716)
G	**Assumptions**							
	At beginning of period							
	Discount rate	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%	5.05%
	Expected rate of return on plan assets	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Hydro One Limited Non-Pension Post Retirement Benefit
Projected 2026 to 2032 Accounting under US GAAP
Active / Inactive Split
Figures in $000s

APPENDIX B.3

Projected OPRB Expense - Hydro One

Components of Benefit Cost	2026 Inactive	2026 Active	2026 Total	2027 Inactive	2027 Active	2027 Total	2028 Inactive	2028 Active	2028 Total	2029 Inactive	2029 Active	2029 Total	2030 Inactive	2030 Active	2030 Total	2031 Inactive	2031 Active	2031 Total	2032 Inactive	2032 Active	2032 Total
Current service cost	-	44,758	44,758	-	47,773	47,773	-	52,307	52,307	-	56,121	56,121	-	59,255	59,255	-	62,081	62,081	-	64,509	64,509
Interest cost	44,372	31,091	75,463	45,536	33,519	79,055	46,730	36,124	82,854	47,990	38,949	86,939	49,297	41,993	91,290	50,732	45,169	95,901	52,096	48,669	100,765
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	2,935	7,313	10,248	2,935	5,460	8,395	2,935	2,539	5,474	1,941	1,423	3,364	727	668	1,395	727	287	1,014	727	-	727
Amortization of net (gain) loss	(7,876)	(5,518)	(13,394)	(6,971)	(5,131)	(12,102)	(6,159)	(4,761)	(10,920)	(5,427)	(4,404)	(9,831)	(4,790)	(4,080)	(8,870)	(4,178)	(3,720)	(7,898)	(3,576)	(3,340)	(6,916)
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Net transfers	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	39,431	77,644	117,075	41,500	81,621	123,121	43,506	86,209	129,715	44,504	92,089	136,593	45,234	97,836	143,070	47,281	103,817	151,098	49,247	109,838	159,085
Credit (charge) to OCI in year	(4,941)	(304)	(5,245)	(4,036)	329	(3,707)	(3,224)	(2,222)	(5,446)	(3,486)	(2,981)	(6,467)	(4,063)	(3,412)	(7,475)	(3,451)	(3,433)	(6,884)	(3,200)	(2,989)	(6,189)

Hydro One Limited Post Employment Benefit
Projected 2026 to 2032 Accounting under US GAAP
Active / Inactive Split
Figures in $000s

Projected PEB Expense

Components of Benefit Cost	2026 Inactive	2026 Active	2026 Total	2027 Inactive	2027 Active	2027 Total	2028 Inactive	2028 Active	2028 Total	2029 Inactive	2029 Active	2029 Total	2030 Inactive	2030 Active	2030 Total	2031 Inactive	2031 Active	2031 Total	2032 Inactive	2032 Active	2032 Total
Current service cost	18,009	-	18,009	19,796	-	19,796	20,828	-	20,828	22,387	-	22,387	23,610	-	23,610	24,547	-	24,547	25,445	-	25,445
Interest cost	7,979	-	7,979	8,428	-	8,428	8,895	-	8,895	9,409	-	9,409	9,952	-	9,952	10,527	-	10,527	11,142	-	11,142
Expected return on plan assets	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of past service cost	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Amortization of net (gain) loss	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Curtailment (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Settlement (gain) / loss recognized	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Total benefit cost recognized in the P&L account	25,988	-	25,988	28,224	-	28,224	29,723	-	29,723	31,796	-	31,796	33,562	-	33,562	35,074	-	35,074	36,587	-	36,587
Credit (charge) to OCI in year	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Appendix C - Statement of Assumptions (RPP and SPS/DSPS)

The rates in the following table are on a per annum basis.

Measurement Date	**December 31, 2025** **(as per year-end disclosures)** **and** **End of December 31** **During Projection Period** **(2026-2032)**
Economic Assumptions	
Discount Rate	5.02%
Expected Long-term Return on Plan Assets (EROA) – RPP only [1]	7.20%
Consumer Price Index (Inflation)	2.00%
Inflation for Post-retirement Pension Increases	2.00%
YMPE Increases	3.00%
Increase in maximum pension under the Income Tax Act	3.00%
Salary increases	2.50% plus merit and promotion For details, refer to Table 1 and Table 2(a) for rates applicable during projection period (2026-2032) and Table 2(b) for rates applicable at December 31, 2025
Demographic assumptions	
Mortality	90% CPM2014 Private Table projected with MI-2024
Retirement rates [2]	Table 3
Termination rates [2]	Table 4
Disability rates	Table 5
Other assumptions	
Eligible spouse at retirement	80%
Spousal age difference	Male 2 years older

Notes:

[1] Return on asset assumption is net of any expenses paid by the trust.

[2] No terminations or retirements were assumed under the DCPP. For the Notional DCPP, terminations and retirements are assumed to be 5% of the Projected Benefit Obligation the beginning of each year.

Appendix C - Statement of Assumptions (Hydro One PRB)

The rates in the following table are on a per annum basis.

Measurement Date	**December 31, 2025** **(as per year-end disclosures)** **and** **End of December 31** **During Projection Period** **(2026-2032)**
Economic Assumptions	
Discount Rate:	5.05%
Salary increases	2.50% plus merit and promotion For details, refer to Table 1 and Table 2(a) for rates applicable during projection period (2026-2032) and Table 2(b) for rates applicable at December 31, 2025
Health Care Trend Rates	
• Prescription Drugs	4.50% per annum
• Hospital	3.00% per annum
• Other Medical	5.61% per annum in 2026 grading to 4.50% per annum in and after 2031
• Dental	4.25% per annum
• Vision Care	2.00% per annum through 2028 and 0% thereafter
Per Capita Claim Costs	Please see Appendix A of the 2025 PRB/PEB/SERP Year-End Report for per capita claim costs, applicable aging factors, and expense / tax rates
Demographic assumptions	
Mortality	90% of CPM2014 Private Sector Table projected with MI-2024
Retirement rates	Table 3
Termination rates	Table 4
Disability rates	Table 5
Other assumptions	
Dependent coverage election at retirement	85%
Spousal age difference	Males 2 years older

Appendix C - Statement of Assumptions (PEB)

The rates in the following table are on a per annum basis.

Measurement Date	**December 31, 2025** **(as per year-end disclosures)** **and** **End of December 31** **During Projection Period** **(2026-2032)**
Economic Assumptions	
Discount Rate:	5.05%
Cost-of-living adjustment on Disability Income and Life Insurance Benefits	1.8% from 2025 to 2026 and 2.00% per annum thereafter
Health Care Trend Rates	
• Medical	5.43% per annum in 2026 grading to 4.30% per annum after 2031
• Dental	4.25% per annum
Per Capita Claim Costs [1]	
• Medical	$8,830 in 2026
• Dental	$2,290 in 2026
Demographic assumptions	
Mortality	Disabled mortality tables from the 2009-2015 CIA Group LTD Termination Study
Disability termination rates	Based on the tables from the 2009-2015 CIA Disability Termination Study
Incurred but not Reported (IBNR) claims	Estimated based on recent experience and an assumption that the average time period between the date of disability and the commencement of LTD benefits is 12 months

Notes:
[1] The values shown are per disabled employee and include a provision for administration expenses and taxes.

Table 1 – Annual salary increases due to movement within the Salary Structure (M&P)

Age	First 4 Years of Employment	Subsequent Years
Under 25	8.0%	3.0%
25 – 29	6.0%	3.0%
30 – 34	4.0%	1.5%
35 – 39	4.0%	1.5%
40 – 44	3.0%	1.5%
45 – 49	2.0%	1.0%
50 – 54	1.0%	1.0%
55 – 59	1.0%	0.5%
60 & over	1.0%	0.0%

Table 2 – Fixed annual increases

(a) Used for 2026 – 2032 projections

Representation	2026	2027	2028-2032	2033 onward
Management	3.50%	3.50%	3.50%	2.50%
Society	3.00%	3.00%	3.00%	2.50%
PWU	4.50%	3.50%	3.00%	2.50%

(b) Used for December 31, 2025 disclosures

Representation	2025	2026-2027	2028 onward
Management	3.50%	2.00%	2.50%
Society	3.50%	2.00%	2.50%
PWU	4.50%	3.50%	2.50%

Table 3 – Annual retirement rates

Age	Eligible for Unreduced Pension: Based on points (82 or 85)	Eligible for Unreduced Pension: 35 years of service and over	Not Eligible for Unreduced Pension
Under 55	13%	25%	0%
55	13%	25%	2%
56 to 59	20%	25%	2%
60	25%	25%	2%
61 to 62	25%	10%	5%
63	15%	10%	5%
64	15%	30%	5%
65	45%	60%	35%
66 to 69	20%	20%	20%
70 and over	100%	100%	100%

Table 4 – Annual termination rates

Service (years)	Male & Female
Under 20	1.2%
20 and over	0%

Table 5 – Annual disability rates

Age	Male & Female
Under 30	0.10%
30 to 39	0.25%
40 to 49	0.45%
50 to 54	0.75%
55 to 59	0.85%
60 and above	1.60%

CHAPTER 2 APPENDIX 2-KA: OPEBS (OTHER POST-EMPLOYMENT BENEFITS) COSTS

This attachment has been filed separately in MS Excel format.

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PENSION AND OPEB COSTS – HOSSM

This Exhibit describes Hydro One Sault Ste. Marie's (HOSSM) pension and other post-employment benefit costs (OPEB) for the 2028-2032 period, in respect of the Transmission business, and the manner in which those costs have been forecasted for purposes of recovery. As pension and OPEB costs are an important part of the overall compensation that is provided to attract and retain skilled employees for the purpose of providing regulated service, HOSSM has historically been permitted to recover such costs through rates, including most recently for the Transmission business in EB-2014-0238. HOSSM's pension and OPEB costs over the test period have been appropriately forecasted in a manner consistent with prior OEB approvals and based on expert actuarial valuation.

1.0 PENSION AND OPEB COSTS OVERVIEW

1.1 BACKGROUND

Prior to the acquisition of Great Lakes Power Transmission LP (GLPT), pension and post-retirement benefits were offered to its employees as follows:

- *Defined Benefit (DB) Pension Plan* to all full-time represented employees regardless of start date, and all full-time non-represented employees who started with the company before January 1, 1997.
- *Defined Contribution Pension Plan* to all non-represented employees who started with the company after January 1, 1997.
- *Post-Employment Benefit Plan* for health, dental, vision and life insurance benefits to all eligible represented employees and eligible non-represented employees who started with the company before January 1, 2005.

With the acquisition of GLPT effective October 31, 2016, the Retirement Plan of Great Lakes Power Limited was changed to the Retirement Plan of HOSSM LP (the "Registered Plan").

As a result of the integration of HOSSM LP operations with Hydro One Networks Inc., employees of HOSSM LP ceased to accrue pension benefits under the Registered Plan as at September 30, 2018 and joined the Hydro One Pension Plan or the Hydro One Defined Contribution Pension Plan (depending on employment type) effective October 1, 2018. The Registered Plan was amended to cease pension accruals as at October 1, 2018 and provide pre-retirement indexation of the accrued pensions for active members while they remain employed with Hydro One Networks Inc. Effective October 1, 2018, the Registered Plan closed and ceased to take new entrants. No member contributions were required nor permitted to be made for the period after September 30, 2018. For certain retired members of the Register Plan who did not receive indexation, supplemental payments are made by HOSSM LP directly to these members (Supplemental Plan). Subsequently, the Defined Contribution Pension Plan was terminated with an effective date of August 1, 2020, and received regulatory approval on January 20, 2022, and all post-employment benefits for pensioners of HOSSM were transferred to the Hydro One OPEB plan.

2.0 DB PLAN

The following sections describe the DB Plan and its governance, the actuarial valuations which determine contribution rates under the DB Plan, cost recovery and wind-up for the DB Plan.

2.1 DB PLAN DESCRIPTION AND GOVERNANCE

The DB Plan is a contributory, defined-benefit pension plan. The DB Plan is registered pursuant to the *Pension Benefits Act* (Ontario) and the *Income Tax Act* (Canada) and is not subject to income tax. Plan members include eligible represented employees of the Power Workers Union (PWU) as well as non-represented management employees, who were hired and met the eligibility requirements to join the plan prior to January 1, 1997, along with pensioners who were previously employees, and pensioners who are beneficiaries or surviving spouses of employees or pensioners.

2.2 DB PLAN ACTUARIAL VALUATION

For DB plans, there is a requirement to complete and file a full actuarial valuation at a minimum every three years. Management can, at its discretion, file these valuations more frequently. The Tri-Annual Actuarial Valuation report for the DB Plan as at December 31, 2025 was filed with the Financial Services Regulatory Authority of Ontario (FSRA), formerly FSCO in March 2026 and is provided as Attachment 1 to this exhibit.

The December 31, 2025 valuation showed that the DB Plan is in a surplus position on both a going concern and wind-up basis. As such, no employer contributions are required.

2.3 DB PLAN COST RECOVERY AND WIND-UP

On August 21, 2025, the Board of Directors for HOSSM approved the wind-up of the Registered Plan effective April 1, 2026. On March 20, 2026, the Registered Plan was amended to facilitate the wind-up including the transfer of the Supplemental Plan's obligations to the Registered Plan on March 31, 2026. Regulatory approval of the Registered Plan's wind-up is assumed to be obtained on March 31, 2028.

A summary of historical and projected pension costs included in HOSSM's rates for 2016 to 2028 are provided as Attachment 2 to this exhibit. For the period from January 1 to March 31, 2026, the projected pension cost was calculated as the 3-month pro-rata of the full year 2026 expense. The projection for the period after March 31, 2026 reflects HOSSM's decision to wind up the Registered Plan on April 1, 2026, resulting in curtailment accounting rules being applied in 2026. The Plan's assets and obligations were remeasured as at April 1, 2026 using the market value of assets and discount rates in effect at that date, and the subsequent settlement of the plan's obligations triggering the recognition of settlement accounting rules were recognized in 2028 assuming regulatory approval of the wind-up on March 31, 2028 (the assumed settlement date). Because of the Plan's surplus position, no employer contributions are assumed to be made over the projection period.

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MERCER
A MARSH BUSINESS

March 23, 2026

Retirement Plan of Hydro One Sault Ste. Marie LP

Report on the Actuarial Valuation for Funding Purposes as at December 31, 2025

Financial Service Regulatory Authority of Ontario Registration Number: 1212844

Canada Revenue Agency Registration Number: 1212844

Note to reader regarding actuarial valuations:

This valuation report may not be relied upon for any purpose other than those explicitly noted in the Introduction, nor may it be relied upon by any party other than the parties noted in the Introduction. Mercer is not responsible for the consequences of any other use. A valuation report is a snapshot of a plan's estimated financial condition at a particular point in time; it does not predict a pension plan's future financial condition or its ability to pay benefits in the future. If maintained indefinitely, a plan's total cost will depend on a number of factors, including the amount of benefits the plan pays, the number of people paid benefits, the amount of plan expenses, and the amount earned on any assets invested to pay the benefits. These amounts and other variables are uncertain and unknowable at the valuation date. The content of the report may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission. All parts of this report, including any documents incorporated by reference, are integral to understanding and explaining its contents; no part may be taken out of context, used, or relied upon without reference to the report as a whole.

To prepare the results in this report, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this report. However, the future is uncertain and the Plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future, and other factors.

The valuation results shown in this report also illustrate the sensitivity to one of the key actuarial assumptions, the discount rate, and the sensitivity to three adverse scenarios. We note that the results presented herein rely on many assumptions, all of which are subject to uncertainty, with a broad range of possible outcomes, and the results are sensitive to all the assumptions used in the valuation.

Should the Plan be wound up, the going concern funded status and solvency financial position, if different from the wind-up financial position, become irrelevant. The hypothetical wind-up financial position estimates the financial position of the Plan assuming it is wound up on the valuation date. Emerging experience will affect the wind-up financial position of the Plan assuming it is wound up in the future. In fact, even if the Plan were wound up on the valuation date, the financial position would continue to fluctuate until the benefits are fully settled.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security, and/or benefit-related issues should not be made solely on the basis of this valuation, but only after careful consideration of alternative economic, financial, demographic, and societal factors, including financial scenarios that assume future sustained investment losses.

Funding calculations reflect our understanding of the requirements of the Ontario Pension Benefits Act, the Income Tax Act, and related regulations that are effective as of the valuation date. Mercer is not a law firm, and the analysis presented in this report is not intended to be a legal opinion. You should consider securing the advice of legal counsel with respect to any legal matters related to this report.

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Section 1

Summary of results

	31.12.2025	31.12.2022
Going Concern Financial Status		
Market value of assets	$30,192,400	$27,828,200
Going concern funding liabilities	$19,940,200	$18,856,200
Provision for adverse deviations in respect of the going concern liabilities	$857,700	$1,920,600
Funding excess (shortfall)	$9,394,500	$7,051,400
Funded ratio	151%	148%
Hypothetical Wind-up Financial Position		
Wind-up assets	$30,072,400	$27,738,200
Wind-up liability	$19,527,600	$22,331,200
Wind-up excess (shortfall)	$10,544,800	$5,407,000
Wind-up ratio	155%	125%
Funding Requirements in the Year Following the Valuation		
Total current service cost	N/A	N/A
Estimated members' required contributions	N/A	N/A
Estimated employer's current service cost	N/A	N/A
Expense allowance	N/A	N/A
Total	N/A	N/A
Minimum special payments	$0	$0
Estimated minimum employer contribution	$0	$0
Estimated maximum eligible employer contribution	$0	$0
Next required valuation date	December 31, 2028	December 31, 2025

Section 2

Introduction

To Hydro One Sault Ste. Marie

At the request of Hydro One Sault Ste. Marie, we have conducted an actuarial valuation of the Retirement Plan of Hydro One Sault Ste. Marie (the "Plan"), sponsored by Hydro One Sault Ste. Marie (the "Company"), as at the valuation date, December 31, 2025. We are pleased to present the results of the valuation.

Purpose

The purpose of this valuation is to determine:

- The funded status of the Plan as at December 31, 2025 on going concern, hypothetical wind-up, and solvency bases;
- The minimum required funding contributions from 2026, in accordance with the *Ontario Pension Benefits Act* (OPBA) (the "Act"); and
- The maximum permissible funding contributions from 2026, in accordance with the *Income Tax Act.*

The information contained in this report was prepared for the internal use of the Company, and for filing with the Financial Services Regulatory Authority and with the Canada Revenue Agency, in connection with our actuarial valuation of the Plan. This report will be filed with the Financial Services Regulatory Authority and with the Canada Revenue Agency. This report is not intended or suitable for any other purpose.

In accordance with pension benefits legislation, the next actuarial valuation of the Plan will be required as at a date not later than December 31, 2028 or as at the date of an earlier amendment to the Plan depending on any funding implications.

Terms of Engagement

In accordance with our terms of engagement with the Company, our actuarial valuation of the Plan is based on the following material terms:

- It has been prepared in accordance with applicable pension legislation and actuarial standards of practice in Canada.
- As instructed by the Company, we have not reflected a margin for adverse deviations in the going concern valuation in excess of the provision for adverse deviations prescribed by the Act.
- We have reflected the Company's decisions for determining the solvency funding requirements, summarized as follows:
  - The same plan wind-up scenario was hypothesized for both hypothetical wind-up and solvency valuations.

- Certain excludable benefits were excluded from the solvency liabilities.
- The solvency financial position was determined on a market value basis.

See the Valuation Results – Solvency section of the report for more information.

Events since the Last Valuation at December 31, 2022

Pension Plan

There have been no special events since the last valuation date.

This valuation reflects the provisions of the Plan as at December 31, 2025. The Plan provisions are summarized in Appendix F.

Assumptions

We have used the same going concern valuation assumptions and methods as were used for the previous valuation, except for the following:

	Current valuation	Previous valuation
Discount rate:	4.25%	5.55%
Inflation:	2.00%	2.05%
ITA limit / YMPE / AIW increases:	3.00%	3.05%
Pension Indexation while active	2.00%	2.05%
Post-retirement pension increase:	1.47%	1.56%
Interest on employee contributions	2.65%	3.40%

A summary of the going concern methods and assumptions is provided in Appendix C.

The hypothetical wind-up and solvency assumptions have been updated to reflect market conditions at the valuation date. A summary of the hypothetical wind-up and solvency methods and assumptions is provided in Appendix D.

Regulatory Environment and Actuarial Standards

There have been no changes to the Act or the relevant regulations which impact the funding of the Plan.

On April 11, 2024, the Canadian Institute of Actuaries (CIA) released a report on Mortality Improvements Research, which summarized the findings of a research project on mortality improvements in Canada and included a new set of mortality improvement rates referred to herein as “MI-2024”. The CIA’s Committee on Pension Plan Financial Reporting issued an Educational Note Supplement on May 15, 2024, which confirmed that, in general, there are three mortality improvement scales that are considered appropriate for pension valuation work in Canada. We assessed the findings of the report on Mortality Improvements Research and concluded that it was appropriate to continue to use the mortality improvement scale from the most recent prior valuation for this valuation.

Subsequent Events

After checking with representatives of the Company, to the best of our knowledge there have been no events subsequent to the valuation date that, in our opinion, would have a material impact on the results of the valuation as at December 31, 2025.

Impact of Case Law

This report has been prepared on the assumption that all claims on the Plan after the valuation date will be in respect of benefits payable to members of the Plan determined in accordance with the Plan terms and that all Plan assets are available to provide for these benefits. It is possible that court and regulatory decisions and changes in legislation could give rise to additional entitlements to benefits under the Plan and cause the results in this report to change.

Section 3

Valuation results – Going concern

Financial Status

A going concern valuation compares the relationship between the value of Plan assets and the present value of expected future benefit cash flows in respect of accrued service and future service for the current membership, assuming the Plan will be maintained indefinitely.

The results of the current valuation, compared with those from the previous valuation, are summarized as follows:

	31.12.2025	31.12.2022
Assets		
Market value of assets	$30,192,400	$27,828,200
Going concern funding target		
Going concern liabilities:		
• Active members	$2,509,900	$2,593,300
• Pensioners and survivors	$17,201,800	$16,112,300
• Deferred pensioners	$228,500	$150,600
Subtotal	$19,940,200	$18,856,200
Provision for adverse deviations in respect of going concern liabilities as prescribed by the Act	$857,700	$1,920,600
Total	$20,797,900	$20,776,800
Funding excess (shortfall)[1]	$9,394,500	$7,051,400

The going concern liabilities at December 31, 2025 do not include an additional margin for adverse deviations beyond the provision for adverse deviations prescribed by the Act.

[1] Funding excess (shortfall) may or may not be equal to the going concern excess (unfunded liability) as described in the Act. Details of the going concern excess (unfunded liability) are provided in Appendix A.

Reconciliation of Financial Status

Funding excess (shortfall) as at previous valuation		**$7,051,400**
Provision for adverse deviations (PfAD) at previous valuation		$1,920,600
Funding excess (shortfall) before PfAD		**$8,972,000**
Interest on funding excess (shortfall) before PfAD at 5.55% per year		$1,578,300
Expected funding excess (shortfall)		$10,550,300
Net experience gains (losses)		
• Investment return	$1,743,300	
• Indexation	($290,400)	
• Mortality	$370,000	
• Retirement	$349,200	
• Termination	($280,400)	
Total experience gains (losses)		$1,891,700
Impact of changes in assumptions		
• Discount rate	($2,640,800)	
• Inflation rate	$168,700	
Total assumption changes impact		($2,472,100)
Data correction		$281,900
Net impact of other elements of gains and losses		$400
Funding excess (shortfall) before PfAD		$10,252,200
Provision for adverse deviations at current valuation		($857,700)
Funding excess (shortfall) as at current valuation		**$9,394,500**

Discount Rate Sensitivity

The following table summarizes the effect on the going concern liabilities and current service cost shown in this report of using a discount rate that is 1% lower than that used in the valuation. For the purposes of the illustration, we have also reduced the interest rate used to determine commuted values upon termination of employment by 1%. The effect of a change in the discount rate on the provision for adverse deviations is not reflected.

Scenario (million's)	Valuation Basis	Reduce Discount Rate by 1%
Present value of accrued and future benefits	$19,940,200	$22,451,500

Plausible Adverse Scenarios

The financial impact on the going concern results of plausible adverse scenarios that would pose threats to the Plan's future financial condition is presented in Appendix G.

Section 4

Valuation results – Hypothetical wind-up

Financial Position

When conducting a hypothetical wind-up valuation, we determine the relationship between the respective values of the Plan's assets and its liabilities assuming the Plan is wound up and settled on the valuation date, assuming benefits are settled in accordance with the Act and under circumstances consistent with the hypothesized scenario on the valuation date. More details on such scenario are provided in Appendix D.

The hypothetical wind-up financial position as of the valuation date, compared with that at the previous valuation, is as follows:

	31.12.2025	31.12.2022
Assets		
Market value of assets	$30,192,400	$27,828,200
Termination expense provision	($120,000)	($90,000)
Wind-up assets	$30,072,400	$27,738,200
Present value of accrued benefits for:		
• Active members	$2,649,700[2]	$3,189,600
• Pensioners and survivors	$16,660,200[3]	$18,938,600
• Deferred pensioners	$217,700	$203,000
Total wind-up liability	$19,527,600	$22,331,200
Wind-up excess (shortfall)	$10,544,800	$5,407,000

Wind-up Incremental Cost

The wind-up incremental cost is an estimate of the present value of the projected change in the hypothetical wind-up liabilities from the valuation date until the next scheduled valuation date, adjusted for the benefit payments expected to be made in that period.

The hypothetical wind-up incremental cost determined in this valuation, compared with the corresponding value determined in the previous valuation, is as follows:

[2] Including pre-retirement indexing of 2.36% granted as of January 1, 2026

[3] Including post-retirement indexing of 2.00% granted as of January 1, 2026

	31.12.2025	31.12.2022
Number of years covered by report	3 years	3 years
Hypothetical wind-up incremental cost	$43,400	$3,800

The incremental cost is not an appropriate measure of the contributions that would be required to maintain the windup position of the Plan even if actual experience is exactly in accordance with the going concern valuation assumptions. For example, the expected return on plan assets (based on the going concern assumptions) is greater than the discount rate used to determine the hypothetical wind-up liabilities.

Discount Rate Sensitivity

The following table summarizes the effect on the hypothetical wind-up liabilities shown in this report of using a discount rate that is 1% lower than that used in the valuation.

Scenario	Valuation Basis	Reduce Discount Rate by 1%
Total hypothetical wind-up liability	$19,527,600	$21,881,400

Plausible Adverse Scenarios

The financial impact on the hypothetical wind-up financial position of plausible adverse scenarios that would pose threats to the Plan’s future financial condition is presented in Appendix G.

Section 5

Valuation results – Solvency

Overview

The Act also requires the financial position of the Plan to be determined on a solvency basis. The financial position on a solvency basis is determined in a similar manner to the Hypothetical Wind-up Basis, except for the following:

Exceptions	Reflected in valuation based on the terms of engagement
The circumstance under which the Plan is assumed to be wound up could differ for the solvency and hypothetical wind-up valuations.	The same circumstances were assumed for the solvency valuation as were assumed for the hypothetical wind-up valuation.
Certain benefits can be excluded from the solvency financial position. These include: (a) any escalated adjustment (e.g. indexing), (b) certain plant closure benefits, (c) certain permanent layoff benefits, (d) special allowances other than funded special allowances, (e) consent benefits other than funded consent benefits, (f) prospective benefit increases, (g) potential early retirement window benefit values, and (h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	The value of the post-retirement indexation has been excluded from solvency liabilities.
The financial position on the solvency basis needs to be adjusted for any Prior Year Credit Balance.	Not applicable.
The solvency financial position can be determined by smoothing assets and the solvency discount rate over a period of up to 5 years.	Smoothing was not used.
The benefit rate increases coming into effect after the valuation date can be reflected in the solvency valuation.	Not applicable.

Financial Position

The financial position on a solvency basis, compared with the corresponding figures from the previous valuation, is as follows:

	31.12.2025	31.12.2022
Assets		
Market value of assets	$30,192,400	$27,828,200
Termination expense provision	($120,000)	($90,000)
Net assets	$30,072,400	$27,738,200
Liabilities		
Total hypothetical wind-up liabilities	$19,527,600	$22,331,200
Value of excluded benefits	($2,886,100)	($4,652,400)
Liabilities on a solvency basis	$16,641,500	$17,678,800
Surplus (shortfall) on a market value basis	$13,430,900	$10,059,400
Transfer ratio	155%	125%

Plausible Adverse Scenarios

The financial impact on the solvency financial position of plausible adverse scenarios that would pose threats to the Plan's future financial condition is presented in Appendix G.

Section 6

Minimum funding requirements

The Act prescribes the minimum contributions that the Company must make to the Plan. The minimum contributions in respect of a defined benefit component of a pension plan are comprised of going concern current service cost, the provision for adverse deviations in respect of the current service cost, and special payments to fund any funding shortfall or solvency shortfall that exceeds the level set out under the Act.

On the basis of the assumptions and methods described in this report, no special payments are required. Since the current service cost is nil, there are no contributions made to the plan.

Other Considerations

Differences between Valuation Bases

There is no provision in the minimum funding requirements to fund the difference between the hypothetical wind-up and reduced solvency shortfalls, if any.

In addition, although minimum funding requirements do include a requirement to fund the going concern current service cost and a provision for adverse deviations in respect of the current service cost, there is no requirement to fund the expected growth in the hypothetical wind-up or solvency liability after the valuation date, which could be greater.

Timing of Contributions

Funding contributions, if any, are due on a monthly basis. Contributions for current service cost and the provision for adverse deviations including the expense allowance must be made within 30 days following the month to which they apply. Special payment contributions must be made in the month to which they apply.

Retroactive Contributions

The Company must contribute the excess, if any, of the minimum contribution recommended in this report over contributions actually made in respect of the period following the valuation date. This contribution, along with an allowance for interest, is due no later than 60 days following the date this report is filed.

Payment of Benefits

The Act imposes certain restrictions on the payment of lump sums from the Plan when the transfer ratio revealed in an actuarial valuation is less than one. If the transfer ratio shown in this report is less than one, the plan administrator should ensure that the monthly special payments are sufficient to meet the requirements of the Act to allow for the full payment of benefits, and otherwise should take the prescribed actions. If the full payment of benefits

does not occur, the residual amount plus interest must be paid within 5 years of the initial transfer.

Additional restrictions are imposed when:

- The transfer ratio revealed in the most recently filed actuarial valuation is less than one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined by 10% or more since the date the last valuation was filed.
- The transfer ratio revealed in the most recently filed actuarial valuation is greater than or equal to one and the administrator knows or 'ought to know' that the transfer ratio of the Plan has declined to less than 0.9 since the date the last valuation was filed.

As such, the administrator should monitor the transfer ratio of the Plan and, if necessary, take the prescribed actions.

Letters of Credit

Minimum funding requirements in respect of required solvency special payments that otherwise require monthly contributions to the pension fund may be met, in the alternative, by establishing an irrevocable letter of credit subject to the conditions established by the Act. Required solvency special payments in excess of those met by a letter of credit must be met by monthly contributions to the pension fund.

Section 7

Maximum eligible Contributions

The *Income Tax Act* (the "ITA") limits the amount of employer contributions that can be remitted to the defined benefit component of a registered pension plan. For purposes of this section on maximum eligible contributions only, any reference to the current service cost includes the provision for adverse deviations in respect of the current service cost.

In accordance with Section 147.2 of the ITA and *Income Tax Regulation* 8516, for a plan that is underfunded on either a going concern or on a hypothetical wind-up basis, the maximum permitted contributions are equal to the employer's current service cost, including the explicit expense allowance if applicable, plus the greater of the going concern funding shortfall and hypothetical wind-up shortfall.

For a plan that is fully funded on both going concern and hypothetical wind-up bases, the employer can remit a contribution equal to the employer's current service cost, including the explicit expense allowance if applicable, as long as the surplus in the plan does not exceed a prescribed threshold. Specifically, in accordance with Section 147.2 of the ITA, for a plan that is fully funded on both going concern and hypothetical wind-up bases, the plan may not retain its registered status if the employer makes a contribution while the going concern funding excess exceeds 25% of the going concern funding target.

Notwithstanding the above, any contributions that are required to be made in accordance with pension benefits legislation are eligible contributions in accordance with Section 147.2 of the ITA and can be remitted.

Section 8

Actuarial opinion

In our opinion, for the purposes of the valuations,

- the membership data on which the valuation is based are sufficient and reliable.
- the assumptions are appropriate.
- the methods employed in the valuation are appropriate.

This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada. It has also been prepared in accordance with the funding and solvency standards set by the *Pension Benefits Act (Ontario).*

DRAFT

Luc Girard
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Date

DRAFT

Christy Kam
Fellow of the Society of Actuaries
Fellow of the Canadian Institute of Actuaries

Date

Appendix A

Prescribed disclosure

Definitions

The Act defines a number of terms as follows:

Defined Term	Description			Result
Going concern assets	Total value of assets plus the sum of the following:			$30,192,400
	(a)	the present value of special payments in respect of any past service unfunded liability identified in a previously filed report	$0	
	(b)	the present value of special payments in respect of any plan amendment that increases going concern liabilities	$0	
	(c)	present value of special payments in respect of going concern unfunded liabilities identified in a previously filed report that are scheduled for payment within one year of the date of this report	$0	
Going concern excess / (unfunded liability)	The Going Concern Assets minus the sum of the following:			$9,394,500
	a.	the going concern liabilities		
		(i) liabilities excluding the value of escalated adjustments	$17,153,400	
		(ii) liabilities in respect of escalated adjustments	$2,786,800	
	b.	the provision for adverse deviations in respect of the going concern liabilities excluding the value of escalated adjustments	$857,700	
	c.	Prior Year Credit Balance	$0	

Defined Term	Description	Result
Going concern funded ratio	The ratio of: (a) Total value of assets (excluding letters of credit) less the Prior Year Credit Balance; to (b) going concern liabilities	1.51
Transfer Ratio	The ratio of: (a) Solvency Assets minus the lesser of the Prior Year Credit Balance and the minimum required employer contributions including the provision for adverse deviations until the next required valuation; to (b) The sum of the Solvency Liabilities and liabilities for benefits, other than benefits payable under qualifying annuity contracts that were excluded in calculating the Solvency Liabilities.	1.55
Solvency Ratio	The ratio of: (a) Solvency Assets related to defined benefits and ancillary benefits plus the total amount of any letters of credit minus the Prior Year Credit Balance (b) the sum of the Solvency Liabilities related to defined benefits and ancillary benefits	1.81
Prior Year Credit Balance	Accumulated sum of contributions made to the pension plan in excess of the minimum required contributions (note: only applies if the Company chooses to treat the excess contributions as a Prior Year Credit Balance).	$0
Solvency Assets	Market value of assets including accrued or receivable income and excluding the value of any qualifying annuity contracts.	$30,192,400

Defined Term	Description	Result
Solvency Asset Adjustment	The sum of:	
	(a) the difference between smoothed value of assets and the market value of assets	$0
	(b) the present value of going concern special payments required to liquidate any past service unfunded liability	$0
	(c) the present value of going concern special payments identified in December 31, 2022 valuation and scheduled for 2026	$0
	(d) the present value of going concern special payments (identified in this report) that are scheduled for payment within 6 years following the valuation date	$0
	(e) the present value of any previously scheduled solvency special payments (excluding those identified in this report)	$0
	(f) the total value of all letters of credit in respect of the special payments due before the valuation date, subject to the limit of 15% of solvency liabilities	$0
		$0
Solvency Liabilities	Liabilities determined as if the plan had been wound up on the valuation date, including liabilities for plant closure benefits or permanent layoff benefits that would be immediately payable if the employer's business were discontinued on the valuation date of the report, but, if elected by the plan sponsor, excluding liabilities for,	$16,641,500
	(a) any escalated adjustment,	
	(b) excluded plant closure benefits,	
	(c) excluded permanent layoff benefits,	
	(d) special allowances other than funded special allowances,	
	(e) consent benefits other than funded consent benefits,	
	(f) prospective benefit increases,	
	(g) potential early retirement window benefit values, and	

Defined Term	Description	Result
	(h) pension benefits and ancillary benefits payable under a qualifying annuity contract.	
Solvency Liability Adjustment	The amount by which Solvency Liabilities are adjusted as a result of using a solvency valuation interest rate that is the average of market interest rates calculated over the period of time used in the determination of the smoothed value of assets.	$0
Solvency Deficiency	The amount, if any, by which the sum of:	
	(a) the Solvency Liabilities	$16,641,500
	(b) the Solvency Liability Adjustment	$0
	(c) the Prior Year Credit Balance	$0
		$16,641,500
	Exceeds the sum of	
	(d) the Solvency Assets net of estimated termination expenses[4]	$30,072,400
	(e) the Solvency Asset Adjustment	$0
		$30,072,400
		$0
Reduced Solvency Deficiency / (Solvency Excess)	The sum of:	
	(a) 85% of the Solvency Liabilities	$14,145,300
	(b) 85% of the Solvency Liability Adjustment	$0
	(c) the Prior Year Credit Balance	$0
		$14,145,300
	minus the sum of:	
	(d) the Solvency Assets net of estimated termination expenses[8]	$30,072,400
	(e) the Solvency Asset Adjustment	$0
		$30,072,400
		($15,927,100)

[4] In accordance with accepted actuarial practice, for purposes of determining the financial position, the market value of plan assets was reduced by a provision for estimated termination expenses payable from the Plan's assets that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

Provision for Adverse Deviations

The provision for adverse deviations has been established in accordance with regulations taking into account the following parameters:

Defined Amount		Results
Fixed Income Component (L)	The sum of the Plan's target allocation of assets (excluding those allocated to annuity contracts and meeting the minimum rating requirement) as described in the regulations according to the investment policy applicable at the valuation date:	100.0%

Investment	Target
Insured Contracts	0.0%
Demand deposits and cash on hand	0.0%
Short term notes and treasury bills	0.0%
Term deposits and guaranteed investment certificates	0.0%
Canadian Bonds and debentures	100.0%
Non-Canadian bonds and debentures	0.0%

Alternative Investment Component (M)	The sum of the Plan's target allocation of assets (excluding those allocated to annuity contracts) meeting requirements as described in the regulations according to the investment policy applicable at the valuation date:	

Investment	Target
Mortgage loans	0.0%
Real estate	0.0%
Real estate debentures	0.0%
Resource properties	0.0%
Venture Capital	0.0%
Corporations referred to in Schedule 3 Subsection 11(2) of federal investment regulations	0.0%
Other	0.0%

Investment Component (N)	Plan's target asset allocation for mutual, pooled or segregated funds	0.0%
Investment Component Fixed Income % (P)	Portion of Investment Component (N) that is allocated to investment categories accounted for in Fixed Income Component (L)	0.0%

Investment Component Alternative Investment % (Q)	Portion of Investment Component (N) that is allocated to investment categories accounted for in Alternative Income Component (M)	0.0%
Annuity Contract Allocation (R)	Annuity contracts that have been purchased from an insurance company and excluded from the Fixed Income Component (L) and Alternative Investment Component (M)	0.0%

Combined Target Asset Allocation for Fixed Income Assets (J)			
Sum of			
• Fixed Income Component (L)	100.0%		
• 0.5 × Alternative Investment Component (0.5 × M)	0.0%		
• Investment Component × Investment Component Fixed Income % (N × P)	0.0%		
• 0.5 × Investment Component × Investment Component Alternative Investment % (0.5 x N × Q)	0.0%		
		100.0%	
Divided by			
• 100% - Annuity Contract Allocation (100% - R)		0.0%	
Combined Target Asset Allocation for Fixed Income Assets			**100.0%**

Combined Target Asset Allocation for Non-Fixed Income Assets (K)	
100% – Combined **Target** Asset Allocation for Fixed Income Assets (100% - J)	**0.00%**

Duration of going concern liabilities at valuation date	
= (F - G) / (G × 0.01)	**12.6**
where,	
G = going concern liabilities at valuation date established using the discount rate determined for this valuation	$19,940,200
F = going concern liabilities established using the discount rate minus 1%	$22,451,500

Benchmark Discount Rate (E)	
Base rate	0.50%
Effective yield from CANSIM Series V39056 (H)	3.85%
1.5% x Combined **Target** Asset Allocation for Fixed Income Assets (1.5% × J)	1.50%
5.0% x Combined **Target** Asset Allocation for Non-Fixed Income Assets (5.0% × K)	0.00%
Benchmark Discount Rate	5.85%

Provision for Adverse Deviations		
i. 5.0% for a closed plan and 4.0% for a Plan that is not a closed plan		5.00%
ii. Provision based on Combined Target Asset Allocation for Non-Fixed Income Assets		0.00%
iii. Greater of zero and the		
• Duration of going concern liabilities at valuation date	12.6%	
Multiplied by:		
– Going concern valuation gross discount rate net of active investment management fees (D), less	4.75%	
– Benchmark Discount Rate (E)	5.85%	0.00%
Provision for Adverse Deviations (i. + ii. + iii.)		5.00%

The available actuarial surplus that may be used according to the Act is established as follows:

Available actuarial surplus			
Excess of			
• Assets determined on basis of going concern valuation including accrued and receivable income but excluding the value of any letters of credit		$30,192,400	
Over			
• Going concern liabilities	$19,940,200		
• Provision for adverse deviations in respect of the going concern liabilities	$857,700		
• Prior Year Credit Balance	$0		
		$20,797,900	
		$9,394,500	(a)
Excess of			
• Solvency assets excluding the value of any letters of credits and lesser of Prior Year Credit Balance and minimum required employer contributions, including the provision for adverse deviations until the next required valuation		$30,192,400	
Over			
• Wind-up liabilities × 105%		$20,504,000	
		$9,688,400	(b)
The available actuarial surplus = the lesser of a) and b) above		$9,394,500	

Timing of Next Required Valuation

In accordance with the Act the next valuation of the Plan would be required at an effective date within one year of the current valuation date if:

- The ratio of solvency assets to solvency liabilities is less than 85%.
- The employer elected to exclude plant closure or permanent lay-off benefits under Section 5(18) of the regulations, and has not rescinded that election.

Otherwise, the next valuation of the Plan would be required at an effective date no later than three years after the current valuation date.

Accordingly, the next valuation of the Plan will be required as of December 31, 2028.

Special Payments

As the Plan does not have a funding shortall and there is a solvency excess, no special payments are required.

Pension Benefits Guarantee Fund (PBGF) Assessment

A PBGF assessment is required to be paid under Section 37 of the Act. The PBGF assessment base and additional information required under Section 14 (8.0.4) of the Regulation 909 under the Act is as follows:

Solvency assets	$30,192,000	(a)
PBGF liabilities	$16,641,000	(b)
Solvency liabilities	$16,641,000	(c)
Ontario asset ratio	100%	(d) = (b) ÷ (c)
Ontario portion of the fund	$30,192,000	
PBGF assessment base	$0	(f) = max(0, (b) – (e))
Amount of additional liability for plant closure and/or permanent layoff benefits which is not funded and subject to the 2% (3% for years after 2018) assessment pursuant to s.37(4)	$0	(g)

Following table required for plans with PBGF liabilities of $10 million or more

	Accrued Pensions Including Bridge Benefits	
	Benefits, In Pay	**Benefits, Not in Pay**
Modified PBGF liabilities	$6,454,000	$1,708,000
Number of Ontario Plan beneficiaries	34	12
Number of Ontario Plan beneficiaries receiving monthly pensions (including bridge benefit) of $1,500 or less	6	0
Number of Ontario Plan beneficiaries who have accrued monthly pensions (including bridge benefit) of $1,500 or less	0	7
Amount of largest monthly pension or monthly pension benefit (including bridge benefit) that has accrued under the plan to an Ontario beneficiary	$9,471	

	Percentiles of amounts payable under Plan to Ontario beneficiaries (in reference to all monthly pensions in pay, including bridge benefits for pensioners and beneficiaries)		Percentiles of amounts payable under Plan to Ontario beneficiaries (in reference to all accrued monthly pensions, including bridge benefits for actives, disabled, suspended, transfers and deferred pensioners)	
	Accrued monthly pension (including bridge benefit)	PBGF liabilities	Accrued monthly pension (including bridge benefit)	PBGF liabilities
10th	$1,138	$350,022	$289	$19,136
20th	$1,557	$673,066	$493	$61,830
30th	$1,855	$1,373,183	$626	$90,173
40th	$2,005	$2,252,631	$901	$178,083
50th	$2,447	$3,102,691	$1,120	$307,831
60th	$3,103	$4,226,238	$1,914	$428,477
70th	$3,881	$6,324,143	$2,483	$771,486
80th	$4,428	$8,232,208	$2,545	$1,147,422
90th	$5,514	$10,643,739	$2,617	$1,526,762

Appendix B

Plan assets

The pension fund is held by CIBC Mellon. In preparing this report, we have relied upon the fund statements prepared by CIBC Mellon for the period from January 1, 2023 to December 31, 2025 without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and we have no reason to doubt its substantial accuracy.

Reconciliation of Market Value of Plan Assets

The pension fund transactions since the last valuation are summarized in the following table:

	2023	2024	2025
December 31	$27,828,230	$30,522,553	$31,656,450
PLUS			
Company's contributions	$0	$0	$0
Investment income	$705,253	$881,782	$1,195,440
Net capital gains (losses)	$3,523,789	$1,817,210	($1,226,571)
	$4,229,042	$2,698,992	($31,131)
LESS			
Pensions paid	$1,279,267	$1,371,566	$1,287,680
Administration and Investment fees	$255,452	$193,529	$145,236
	$1,534,719	$1,565,095	$1,432,916
December 31	$30,522,553	$31,656,450	$30,192,403
Gross rate of return[5]	15.63%	9.08%	(0.10%)
Rate of return net of expenses[6]	14.61%	8.40%	(0.57%)

We have tested the pensions paid, the lump-sums paid, and the contributions for consistency with the membership data for the Plan members who have received benefits or made contributions. The results of these tests were satisfactory.

[5] Assuming mid-period cash flows.
[6] Assuming mid-period cash flows.

Investment Policy

The plan administrator has adopted a statement of investment policy and procedures. This policy is intended to provide guidelines for the manager(s) as to the level of risk that is consistent with the Plan's investment objectives. A significant component of this investment policy is the asset mix.

The plan administrator is solely responsible for selecting the Plan's investment policies, asset allocations, and individual investments.

The constraints on the asset mix and the actual asset mix at the valuation date are provided for information purposes:

	Investment Policy			Actual asset Mix as at December 31, 2025
	Minimum	Target	Maximum	
Canadian Universe Bonds	0%	20%	100%	19%
Canadian Long Bonds	0%	80%	100%	80%
Cash and cash equivalents	0%	0%	0%	1%
		100%		100%

Because the Plan's assets (which are invested in accordance with the above investment policy) are not matched to the Plan's liabilities (which tend to behave like long bonds), the Plan's financial position will fluctuate over time. These fluctuations could be significant and could cause the Plan to become underfunded or overfunded even if the Company contributes to the Plan based on the funding requirements presented in this report.

Appendix C

Methods and assumptions – Going concern

Valuation of Assets

For this valuation, we have used the market value of assets.

Going Concern Funding Target

Over time, the real cost to the employer of a pension plan is the excess of benefits and expenses over member contributions, if any, and investment earnings. The actuarial cost method allocates this cost to annual time periods.

For purposes of the going concern valuation, we have continued to use the projected unit credit actuarial cost method. Under this method, we determine the present value of benefit cash flows expected to be paid in respect of service accrued prior to the valuation date, based on the frozen accrued benefit as of October 1, 2018. This is referred to as the funding target. For each individual plan member, accumulated contributions with interest are established as a minimum actuarial liability.

The funding excess or funding shortfall, as the case may be, is the difference between the market or smoothed value of assets and the funding target. A funding excess on a market value basis indicates that the current market value of assets and expected investment earnings are expected to be sufficient to meet the cash flows in respect of benefits accrued to the valuation date as well as expected expenses – assuming the plan is maintained indefinitely. A funding shortfall on a market value basis indicates the opposite – that the current market value of the assets is not expected to be sufficient to meet the plan's cash flow requirements in respect of accrued benefits, absent additional contributions.

As required under the Act, a funding shortfall (including the prior year credit balance) and the provision for adverse deviations must be amortized over no more than 10 years through special payments beginning one year after the valuation date. A funding excess may, from an actuarial standpoint, be applied immediately to reduce required employer current service contributions unless precluded by the terms of the plan or by legislation.

The actuarial cost method used for the purposes of this valuation produces a reasonable matching of contributions with accruing benefits. Because benefits are recognized as they accrue, the actuarial cost method provides an effective funding target for a plan that is maintained indefinitely.

Current Service Cost

The current service cost is the present value of projected benefits to be paid under the plan with respect to service expected to accrue during the period until the next valuation.

All members ceased to accrued pension benefit under the plan as at September 30, 2018, there is no further current service cost.

Actuarial Assumptions –Going Concern Bases

The present value of future benefit payment cash flows is based on economic and demographic assumptions. At each valuation we determine whether, in our opinion, the actuarial assumptions are still appropriate for the purposes of the valuation, and we revise them, if necessary. Emerging experience will result in gains or losses that will be revealed and considered in future actuarial valuations.

The table below shows the various assumptions used in the current valuation in comparison with those used in the previous valuation.

Assumption	Current valuation	Previous valuation
Discount rate:	4.25%	5.55%
Inflation:	2.00%	2.05%
ITA limit / YMPE increases:	3.00%	3.05%
Pension indexation while active:	2.00%	2.05%
Post-retirement pension increases:	1.47%	1.56%
Interest on employee contributions:	2.65%	3.40%
Retirement rates:	25% at each age starting at unreduced age until age 64; remainder at age 65	25% at each age starting at unreduced age until age 64; remainder at age 65
Termination rates:	None	None
Mortality rates:	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)	95% of the rates of the 2014 Private Sector Canadian Pensioners Mortality Table (CPM2014Priv)
Mortality improvements:	Fully generational using CPM Improvement Scale B (CPM-B)	Fully generational using CPM Improvement Scale B (CPM-B)
Disability rates:	None	None
Eligible spouse at retirement:	80%	80%
Spousal age difference:	Male 3 years older	Male 3 years older

The assumptions are best estimates and do not include a margin for adverse deviations.

Stochastic model of inflation

The post-retirement pension increases assumption is based on the Plan's partial indexation formula and a stochastic model of inflation.

The stochastic model of inflation is based on an assumption of median inflation of 2.00% per year (consistent with the Bank of Canada's target) and a distribution of annual inflation which is consistent with the last 30 years of history.

A model based on the last 30 years of history strikes a reasonable balance between the relatively stable inflation experience of the past 20 years (during which the Bank of Canada actively managed inflation) and a somewhat longer period exhibiting greater variation. This approach recognizes that future inflation will continue to be actively managed by the Bank of Canada but that it can also be impacted by external economic factors (such as US Monetary policies) beyond local control. Consequently, future annual inflation may be outside the 1%-3% range currently targeted by the Bank of Canada.

The assumed distribution of inflation was determined based on historical 12-month periods over the past 30 years. The distribution differs from a log-normal distribution in that it is more skewed to the right and has fatter tails. Although calendar year experience over the past 30 years did not exhibit deflation, some 12-month periods did, and the modeled distribution does provide for a small probability of deflation.

The model also displays relatively high serial correlation i.e. years of high inflation tend to be followed by years with similarly high inflation, and the same with low inflation.

The model produces 1,000 scenarios over a 20 years period. The modeled scenarios have the following characteristics:

	Current valuation
Annualized inflation over 20 years:	Median: 2.00% Minimum: 0.21% Maximum: 7.41% Approximate 70% of scenarios between 1.0% and 3.0%
Volatility of inflation:	Annual standard deviation of 2.6% over a single year in the long-term (lower in the short-term due to serial correlation) Average, calculated over the 1,000 scenarios, of standard deviation over 20 years: 2.1%

Rationale for Assumptions

A rationale for each of the assumptions used in the current valuation is provided below.

Discount Rate

We have discounted the expected benefit payment cash flows using the expected investment return on the market value of the fund net of fees. Other bases for discounting the expected benefit payment cash flows may be appropriate, particularly for purposes other than those specifically identified in this valuation report.

The discount rate is comprised of the following:

- An **assumed investment return** based on estimated returns for each major asset class that are consistent with market conditions on the valuation date modified to include a provision for increases in market interest rates to a level higher than current historically low levels, on the expected time horizon over which benefits are expected to be paid, and on the target asset mix specified in the Plan's investment policy.
- An **assumed passive investment management expense provision** which represents the hypothetical fees for passive investment management of assets based on estimated fees charged by index managers for balanced mandates.
- An **implicit non-investment management expense provision** determined as the average rate of non-investment expenses paid from the fund over the last 3 years. These would include all fees payable from the fund (administration, custodial, audit, consulting, etc.) except those payable to investment managers, to the extent that these fees are not covered in an explicit provision for expenses added to the current service cost.

The discount rate was developed as follows:

Assumed investment return	4.75%
Passive investment management expense provision	(0.09%)
Implicit non-investment management expense provision	(0.40%)
Rounding	(0.01%)
Net discount rate	4.25%

Inflation

The inflation assumption is based on market expectations of long-term inflation implied by the yields on nominal and real return bonds at the valuation date.

Income Tax Act Pension Limit and Year's Maximum Pensionable Earnings

The assumption is based on historical real economic growth and the underlying inflation assumption.

Pre-Retirement Pension Increases

The assumption is based on the Plan formula and inflation assumption above.

Post-Retirement Pension Increases

The assumption is based on the Plan formula and stochastic model of inflation.

Retirement Rates

Due to the size of the Plan, there is no meaningful retirement experience. The assumption is based on the actual retirement experience observed during the years 2003 to 2012 for all Canadian defined benefit plans sponsored by Brookfield Renewable, the prior owner of the Company. We have combined the experience of the defined benefit plans to increase the results' credibility.

Termination Rates

Use of a different assumption would not have a material impact on the valuation.

Mortality Rates

The assumption for the mortality rates is based on the Canadian Pensioners' Mortality (CPM) study published by the Canadian Institute of Actuaries in February 2014. Considering the characteristics of the group, it was considered appropriate to use the CPM mortality rates from the private sector as a reference table.

Due to the size of the Plan, specific data on plan mortality experience is insufficient to determine the mortality rates. The CPM mortality rates from the private sector have been adjusted after considering plan-specific characteristics, such as the type of employment, the industry experience, the pension and employment income for the plan members, and data in the CPM study.

There is broad consensus among actuaries and other longevity experts that mortality improvement will continue in the future, but the degree of future mortality improvement is uncertain. In general, there are three mortality improvement scales that are considered appropriate for pension valuation work in Canada (CPM-B, MI-2017, MI-2024).

For the current valuation, we have continued to use the CPM-B scale, which is a reasonable outlook for future mortality improvements. Based on the assumption used, the life expectancy of a member age 65 at the valuation date is 22.5 years for males and 24.8 years for females.

COVID-19 has impacted mortality rates globally. Statistics Canada reported excess mortality in 2020-2022 and into 2023 for the general Canadian population and other peer countries globally have also seen excess mortality over the course of the pandemic. Mortality experience for the plan has been reflected up to the date of the valuation. We have not adjusted the expected mortality rates for Plan members after the valuation date. The long-term implications of the pandemic on mortality rates is unclear as at the date of this report. Credible plan specific experience and relevant broader observed mortality trends after the report date will be reflected in future valuations.

Interest on Employee Contributions

The assumption is based on Plan terms and is equal to the average of the yields of 5-year personal fixed term chartered bank deposits (CANSIM series V122515) in the year prior to the valuation date.

Disability Rates

Use of a different assumption would not have a material impact on the valuation.

Eligible Spouse

The assumption is based on an industry standard for non-retired members (actual status used for retirees).

Spousal Age Difference

The assumption is based on an industry standard showing males are typically 3 years older than their spouse.

Appendix D

Methods and assumptions – Hypothetical wind-up and solvency

Hypothetical Wind-up Basis

The Canadian Institute of Actuaries requires actuaries to report the financial position of a pension plan on the assumption that the plan is wound up on the effective date of the valuation, with benefits determined on the assumption that the pension plan has neither a surplus nor a deficit.

To determine the actuarial liability on the hypothetical wind-up basis, we have valued those benefits that would have been paid had the Plan been wound up on the valuation date, with all members fully vested in their accrued benefits.

The Standards of Practice of the Canadian Institute of Actuaries require that the scenario upon which the hypothetical wind-up valuation is based be postulated. However, there are no benefits under the Plan contingent upon the circumstances of the plan wind-up or contingent upon other factors. Therefore, it was not necessary to postulate a scenario upon which the hypothetical wind-up valuation is made. No benefits payable on plan wind-up were excluded from our calculations. The plan wind-up is assumed to occur in circumstances that maximize the actuarial liability.

Upon plan wind-up, members are given options for the method of settling their benefit entitlements. The options vary by eligibility and by province of employment, but in general, involve either a lump sum transfer or an immediate or deferred pension.

The value of benefits assumed to be settled through a lump sum transfer is based on the assumptions described in Section 3500 – *Pension Commuted Values* of the Canadian Institute of Actuaries' Standards of Practice applicable for December 31, 2025.

Benefits provided as an immediate or deferred pension are assumed to be settled through the purchase of annuities based on an estimate of the cost of purchasing annuities.

We have estimated the cost of settlement through purchase of annuities in accordance with the *Canadian Institute of Actuaries Educational Note Supplement: Guidance for Assumptions for Hypothetical Wind-up and Solvency Valuations Update – Effective December 31, 2025, and Applicable to Valuations With Effective Dates on or After December 31, 2025, and No Later Than June 29, 2026.(the "Educational Note")*.

However, there is limited data available to provide credible guidance on the cost of a purchase of indexed annuities in Canada. The post-retirement interest rate was determined based on the Plan's indexation formula and a stochastic model of inflation. The stochastic model of inflation is based on an assumption of median inflation of 1.93% per year (difference between the yield on Government of Canada marketable bonds with maturities over 10 years (CANSIM series V39062) and the yield on real-return bonds (CANSIM series

V39057)) and a distribution of annual inflation which is consistent with the last 30 years of history.

A model based on the last 30 years of history strikes a reasonable balance between the relatively stable inflation experience of the past 20 years (during which the Bank of Canada actively managed inflation) and a somewhat longer period exhibiting greater variation. This approach recognizes that future inflation will continue to be actively managed by the Bank of Canada but that it can also be impacted by external economic factors (such as US Monetary policies) beyond local control. Consequently, future annual inflation may be outside the 1%-3% range currently targeted by the Bank of Canada.

The assumed distribution of inflation was determined based on historical 12-month periods over the past 30 years. The distribution differs from a log-normal distribution in that it is more skewed to the right and has fatter tails. Although calendar year experience over the past 30 years did not exhibit deflation, some 12-month periods did, and the modeled distribution does provide for a small probability of deflation.

The model also displays relatively high serial correlation i.e. years of high inflation tend to be followed by years with similarly high inflation, and the same with low inflation.

The model produces 1,000 scenarios over a 20-year period. The modeled scenarios have the following characteristics:

	Current valuation
Annualized inflation over 20 years:	Median: 1.93% Minimum: 0.14% Maximum: 7.34% Approximate 70 % of scenarios between 1.0% and 3.0%
Volatility of inflation:	Annual standard deviation of 2.6% over a single year in the long-term (lower in the short-term due to serial correlation) Average, calculated over the 1,000 scenarios, of standard deviation over 20 years: 2.1%

The Educational Note provides guidance on estimating the cost of annuity purchases assuming a typical group of annuitants. That is, no adjustments for sub- or super-standard mortality are considered. However, it is expected that insurers will consider plan experience and certain plan-specific characteristics when determining the mortality basis for a particular group. The Educational Note states that the actuary would be expected to make an adjustment to the regular annuity purchase assumptions where there is demonstrated substandard or super-standard mortality or where an insurer might be expected to assume so. In such cases, the actuary would be expected to make an adjustment to the mortality assumption in a manner consistent with the underlying annuity purchase basis. Given the uncertainty surrounding the actual mortality basis that would be typical of a group annuity purchase, it is reasonable to assume that there is a range of bases that can be expected not to be materially different from the actual mortality basis. Therefore, an adjustment to the regular annuity purchase assumptions would be warranted when the plan’s assumed basis

falls outside that range. In this context, we have determined that no adjustment to the mortality rates used in the regular annuity purchase assumptions is required.

We have not included a margin for adverse deviations in the solvency and hypothetical wind-up valuations.

The assumptions are as follows:

Form of Benefit Settlement Elected by Member	
Lump sum:	70% of active members under age 55, and 50% of active members over age 55, elect to receive their benefit entitlement in a lump sum
Annuity purchase:	All remaining members are assumed to elect to receive their benefit entitlement in the form of a deferred or immediate pension. These benefits are assumed to be settled through the purchase of deferred or immediate annuities from a life insurance company.
Basis for Benefits Assumed to be Settled through a Lump Sum	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Scale B
Interest rate:	3.50% per year for 10 years, 5.00% per year thereafter
Post retirement indexation (for indexed pensions):	1.96% per year for 10 years, 1.96% per year thereafter
Basis for Benefits Assumed to be Settled through the Purchase of an Annuity	
Mortality rates:	100% of the rates of the 2014 Canadian Pensioners Mortality Table (CPM2014) with fully generational improvements using CPM Scale B
Adjustment to mortality rates:	No adjustment
Interest rate:	4.56% (4.90% for non-indexed pension) and 3.13% per year after retirement date (net of post-retirement indexation) based on a duration of 9.1 years determined for the liabilities assumed to be settled through the purchase of an annuity.
Retirement Age	
Benefits assumed to be payable through a lump sum:	Members are assumed to retire with a 50% probability at the age that maximizes the value of their entitlement from the Plan and a 50% probability at the member's earliest unreduced age in accordance with applicable legislation and based on the eligibility requirements that have been met at the valuation date
Benefits assumed to be settled through the purchase of an annuity:	Members are assumed to retire at the age that maximizes the value of their entitlement from the Plan, based on the eligibility requirements that have been met at the valuation date

Grow-in:	The benefit entitlement and assumed retirement age of Ontario members whose age plus service equals at least 55 at the valuation date reflect their entitlement to grow into early retirement subsidies
Other Assumptions	
Family composition:	Same as for going concern valuation
Maximum pension limit:	$3,932.22 for each year of service
Termination expenses:	$120,000

To determine the hypothetical wind-up position of the Plan, a provision has been made for estimated termination expenses payable from the Plan's assets in respect of actuarial and administration expenses that may reasonably be expected to be incurred in terminating the Plan and to be charged to the Plan.

In addition, termination expenses also include a provision for transaction fees related to the liquidation of the Plan's assets and for expenses that may reasonably be expected to be paid by the pension fund under the postulated scenario between the wind-up date and the settlement date. It was assumed for this purpose that the termination process would extend over a two-year period. Because the settlement of all benefits on wind-up is assumed to occur on the valuation date and is assumed to be uncontested, the provision for termination expenses does not include custodial, investment management, auditing, consulting, and legal expenses that would be incurred between the wind-up date and the settlement date or due to the terms of a wind-up being contested.

Expenses associated with the distribution of any surplus assets that might arise on an actual wind-up are also not included in the estimated termination expense provisions.

In determining the provision for termination expenses payable from the Plan's assets, we have assumed that the plan sponsor would be solvent on the wind-up date. We have also assumed, without analysis, that the Plan's terms as well as applicable legislation and court decisions would permit the relevant expenses to be paid from the Plan.

Although the termination expense assumption is a best estimate, actual fees incurred on an actual plan wind-up may differ materially from the estimates disclosed in this report.

Incremental Cost

In order to determine the incremental cost, we estimate the hypothetical wind-up liabilities at the next valuation date. We have assumed that the cost of settling benefits by way of a lump sum or purchasing annuities remains consistent with the assumptions described above. Since the projected hypothetical wind-up liabilities will depend on the membership in the Plan at the next valuation date, we must make assumptions about how the Plan membership will evolve over the period until the next valuation.

We have assumed that the Plan membership will evolve in a manner consistent with the going concern assumptions as follows:

- Members terminate, retire, and die consistent with the termination, retirement, and mortality rates used for the going concern valuation.
- The Income Tax Act pension limit, and the Year's Maximum Pensionable Earnings increase in accordance with the related going concern assumptions.

Solvency Basis

In determining the financial position of the Plan on the solvency basis, we have excluded the value of escalated adjustments (e.g. indexing) from the solvency liabilities.

We have used the same assumptions and methodology as were used for determining the financial position of the Plan on the hypothetical wind-up basis except for the following:

Basis for Benefits Assumed to be Settled Through the Purchase of a Lump Sum	
Interest Rate:	3.50% per year for 10 years, 5.00% per year thereafter
Indexation rates:	Nil
Basis for Benefits Assumed to be Settled Through the Purchase of an Annuity	
Interest Rate:	4.90% per year based on a duration over 9.1 years determined for the liabilities assumed to be settled through the purchase of an annuity
Indexation rates:	Nil

The solvency position is determined in accordance with the requirements of the Act.

Appendix E

Membership data

Analysis of Membership Data

The actuarial valuation is based on membership data as at December 31, 2025, provided by the Company.

We have applied tests for internal consistency, as well as for consistency with the data used for the previous valuation. These tests were applied to membership reconciliation, basic information (date of birth, date of hire, date of membership, gender, etc.), accrued benefits, credited service, contributions accumulated with interest, and pensions to retirees and other members entitled to a deferred pension. Contributions, lump sum payments, and pensions to retirees were compared with corresponding amounts reported in financial statements. The results of these tests were satisfactory.

If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Plan membership data are summarized below. For comparison, we have also summarized corresponding data from the previous valuation.

	31.12.2025	31.12.2022
Active Members		
Number	10	15
Average accrued lifetime pension	$14,378	$12,742
Average years of pensionable service	9.6 years	9.7 years
Average age	49.5 years	49.9 years
Accumulated contributions with interest	$475,873	$669,971
Deferred Pensioners		
Number	2	2
Total annual pension	$22,338	$22,338
Average annual pension	$11,169	$11,169
Average age	55.4 years	52.4 years
Pensioners and Survivors		
Number	34	31

	31.12.2025	31.12.2022
Total annual lifetime pension	$1,195,679	$1,177,845
Total annual temporary pension for the following year	$46,601	$87,119
Average annual lifetime pension	$35,167	$37,995
Average age	73.7 years	72.0 years

The membership movement for all categories of membership since the previous actuarial valuation is as follows:

	Actives	Deferred Pensioners	Pensioners and survivors	Total
Total at 31.12.2022	15	2	31	48
New entrants				
Terminations:				
• Not vested				
• Transfers/lump sums	(1)			(1)
• Deferred pensions				
Deaths			(4)	(4)
Retirements	(4)		4	0
Beneficiaries			3	3
Total at 31.12.2025	10	2	34	46

The distribution of the active members by age and pensionable service as at the valuation date is summarized as follows:

	Years of Pensionable Service							
Age	0-4	5-9	10-14	15-19	20-24	25-29	30 +	Total
35 to 39								
40 to 44	3							3
45 to 49	1	1		1				3
50 to 54				3				3
55 to 59								
60 to 64				1				1
Total	4	1	0	5				10

The distribution of the inactive members by age as at the valuation date is summarized as follows:

Age	Number	Average Pension	Number	Average Pension
45 – 49				
50 – 54	1	$783		
55 – 59	1	$1,078	1	$1,415
60 – 64			5	$2,495
65 – 69			8	$2,700
70 – 74			5	$5,213
75 – 79			6	$2,947
80 – 84			3	$3,617
85 – 89			4	$1,352
90 – 94			2	$2,074
Total	2	$931	34	$2,931

Appendix F

Summary of plan provisions

Mercer has used and relied on the plan documents, including amendments and interpretations of plan provisions, supplied by Company. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

This valuation is based on the plan provisions in effect on December 31, 2025. Since the previous valuation, the Plan has been amended with respect to cease accruing pension benefit under the Plan as at September 30, 2018 and introducing annual pre-retirement indexation starting on January 1, 2020 for active employees.

The following is a summary of the main provisions of the Plan in effect on December 31, 2025. This summary is not intended as a complete description of the Plan.

Background

The Retirement Plan of Great Lakes Power Limited (the "Plan") was preceded by the Retirement Annuity Plan (the "Previous Plan"), which was established on January 1, 1940, and was underwritten by Canada Life Assurance Company Group Annuity Policy P.747. Effective January 1, 1966, the Previous Plan was replaced by the Amended Retirement Annuity Plan. Contributions to the Previous Plan were discontinued and Policy P.747 was placed on a paid-up basis. Effective April 1, 1987, Policy P.747 assets and liabilities were rolled into the Plan. A separate plan was established for designated executives on January 1, 1980, and the assets and liabilities under the Amended Retirement Annuity Plan for executives who became covered under the Retirement Plan for Designated Executives of Great Lakes Power Limited were transferred to this newly established plan. With effect from January, 1981, the name of the Amended Retirement Annuity Plan was changed to the Retirement Plan of Great Lakes Power Limited.

The Plan was restated effective January 1, 1988, to comply with the revised Pension Benefits Act (Ontario) and incorporate all amendments up to January 1, 1993. The Plan was then amended and restated effective January 1, 1992 to incorporate all of the revisions necessary to comply with the Income Tax Act. Effective January 1, 1997, the Company started a Defined Contribution Plan for all employees, who are not members of the union. All non-union members were given the option of continuing in this Plan or transferring to the defined contribution plan. The Plan has been amended further from time to time since January 1, 1992.

Effective July 1, 2009 employees of the "Distribution" and "Transmission" businesses of Great Lakes Power Limited (the "Company") were transferred to separate companies affiliated with the Company, Great Lakes Power Distribution Inc. ("GLPD") and Hydro One Sault Ste. Marie ("GLPT"). These employees were members of the Plan prior to July 1, 2009. New pension plans were established for the current and future employees of GLPD and GLPT. In January 2011, the Financial Services Commission of Ontario has approved the transfer of assets and liabilities from the Plan to the new pension plans with respect to the transferred employees' benefits accrued prior to July 1, 2009 in the Plan as well as benefits in the Plan for inactive members formerly employed by the "Distribution" and "Transmission" businesses of the Company. The transfer of assets occurred in May 2011.

Effective October 31, 2016, Great Lakes Power Transmission LP was acquired by Hydro One Limited and effective January 16, 2017 its name is changed to Hydro One Sault Ste. Marie LP. Further to the acquisition, the Plan name is changed to Retirement Plan of Hydro One Sault Ste. Marie LP.

As a result of the integration of the Company operations into the business of Hydro One Networks Inc. ("HONI"). The Plan has been amended further as follows:

	(a) Represented employees of the Company who became employees of HONI ceased to accrue pension benefits under the Plan as at September 30, 2018 and joined the Hydro One Pension Plan effective October 1, 2018; (b) Non-represented employees of the Company who became employees of HONI ceased to accrue pension benefits under the Plan as at September 30, 2018 and joined the Hydro One Defined Contribution Pension Plan effective October 1, 2018; (c) For Plan members who were employees of the Company on September 30, 2018 and who became employed by HONI on October 1, 2018, Credited Service under the Plan is frozen as at September 30, 2018 but continuous employment with HONI continues to be recognized for eligibility to benefits under the Plan; and (d) For Plan members who were employees of the Company on September 30, 2018 and who became employed by HONI on October 1, 2018, their accrued pension under the Plan as at September 30, 2018 will be granted annual pre-retirement indexation starting on January 1, 2020 based on 100% of the increase in CPI in the 12 month period ending on September 30 of the preceding year.
Eligibility for Membership	The Plan is closed to new entrants effective October 1, 2018.
Employee Contributions	No member contributions are required nor permitted to be made for the period after September 30, 2018.

Retirement Dates	Normal Retirement Date • The normal retirement date is the first day of the month coincident with or next following the member's 65th birthday. Early Retirement Date • Members who have attained age 55 and 24 months of continuous membership may retire early on a reduced pension. The reduction is ¼ of 1% for each month prior to age 65. Members who have attained age 55 and for whom the sum of age plus continuous years of service amount to not less than 85, may retire early with an unreduced pension. • All members who retire early will also receive a temporary pension (payable for life but in no event past age 65) of 0.7% of the member's average annual gross earnings used in the calculation of the lifetime pension up to the average YMPE for the five calendar years immediately preceding the calendar year of retirement times years of credited service since January 1, 1966 (maximum 35 years). Postponed Retirement • An active member may postpone retirement beyond the normal retirement date, but not beyond the end of the calendar year in which they attain age 71. Under these circumstances, members are entitled to continue membership in the plan and have the right to continue to accrue pension benefits. The pension benefit accrued up to Normal Retirement Date shall be actuarially increased to reflect such postponement.
Normal Retirement Pension	Each member retiring at his Normal Retirement Date will be entitled to receive an annual pension benefit, payable monthly equal to: • 2.0% of the member's average annual gross earnings for the five consecutive calendar years, during the 10 calendar years preceding Normal Retirement Date that produce the highest such average, times the number of years of Credited Service (subject to a maximum of 40 years); Less • 0.7% of such earnings not in excess of the average YMPE for the five calendar years, immediately preceding the calendar year of the Normal Retirement Date, times the number of years of Credited Service since January 1, 1966, (maximum 35 years). Credited Service is equal to Continuous Service from date of employment with the Company for members who joined the plan when first eligible prior to January 1, 1991. For other members, Credited Service is equal to Continuous Service from the date of plan entry. Credited Service shall not include any period of time on or after October 1, 2018. Gross Earnings under the Plan were frozen on September 30, 2018. The above pension formula applies for members retiring after January 1, 2004. A previous formula applied for members retiring before such date. In no event, however, will the member's benefit exceed the applicable maximum pension limits as prescribed by the Income Tax Act.

Maximum Pension	The maximum pension provisions are as follows: Pre-1992 Service Maximum Pension • The member's pension shall not exceed the member's years of pensionable service, prior to January 1, 1992, to a maximum of 35 years multiplied by the lesser of: (i) $1,715; and (ii) 2.0% of the average of the member's best three consecutive years' remuneration from the Company. Post-1991 Service Maximum Pension • The member's pension shall not exceed the member's years of pensionable service, on or after January 1, 1992, multiplied by the lesser of: (i) $3,932.22 or such greater amount permitted under the Income Tax Act; and (ii) 2.0% of the member's highest average indexed compensation, as defined in the Income Tax Act.
Pre Retirement Indexation	A member who retires from continuous service with Hydro One Networks Inc. on or after October 1, 2018 is granted annual pre-retirement indexation starting on January 1, 2020 and ending on the January 1 immediately preceding the Member's cessation of Continuous Service with Hydro One Networks Inc., based on 100% of the increase in CPI in the 12 month period ending on September 30 of the preceding year.
Post Retirement Adjustments	A member who retires from active service on or after January 1, 1995 will have their pension adjusted annually. The annual adjustment will be granted in January of each year, based on the increase in the Consumer Price Index (CPI) for the 12 months ending the previous September 30th. For example, the adjustment effective January 2000, will be based on the increase in the CPI for the period September 30, 1998 to September 30, 1999. If the CPI increase is less than 2.0%, then the annual adjustment is equal to 100% of the CPI increase. Otherwise the annual adjustment is equal to 50% of the CPI increase, with a minimum adjustment of 2.0% and a maximum adjustment of 5.0%. Members who have retired less than 12 months prior to the January adjustment will receive a pro-rata share of the increase based on the number of months since commencement. • As of September 1, 2009, the Plan is amended to grant an ad-hoc increase in certain retired members' pensions.
Disability Benefits	A member who suffers total and permanent disability will receive, commencing at his normal retirement date, an immediate pension calculated as for normal retirement, except that: (a) the service of the member with the Company will include the period during which the member is totally and permanently disabled; and (b) it will be assumed that the member continued to contribute to the plan and to receive remuneration from the Company at the rate of his required contribution and of his earnings at the time of disability.

Death Before Retirement	**For Service Prior to January 1, 1987** In event of death before retirement but on or after July 1, 2012, the surviving spouse if any, otherwise the designated beneficiary, will receive a lump sum refund of the member's contributions, if any, with interest. **For Service on and After January 1, 1987** In the event of death before retirement but on or after July 1, 2012, the surviving spouse if any, otherwise the designated beneficiary, will receive the commuted value of the deferred pension plus a refund of excess contributions, if any. The surviving spouse may elect to receive the death benefit in the form of an annuity instead of receiving a lump sum. Excess contributions are employee contributions, if any, plus interest, in excess of those required to fund 50% of the commuted value of the deferred pension.
Death After Retirement	Upon death of the member after retirement, the member's spouse, if then surviving, will receive an annuity for life equal to 50% of the pension that the member had been receiving. Under the Pension Benefits Act (Ontario), married members must receive a joint and survivor pension that pays at least 60% of the amount of pension that the member had been receiving, unless both the member and spouse waive this option. The amount of pension would be actuarially equivalent to the normal form of pension. In the case of a member without a spouse at retirement, the normal form of pension guarantees a minimum return equal to the member's contributions with interest to date of retirement. The member may also elect an optional form of pension prior to retirement.
Termination Benefits	**For Service Prior to January 1, 1987** A member whose employment terminates on or after July 1, 2012 is entitled to a deferred pension commencing at his Normal Retirement Date, calculated on the same basis as the retirement but based on earnings and service completed to the date of termination and excluding pre-retirement indexation. **For Service On and After January 1, 1987** A member whose employment terminates on or after July 1, 2012 is entitled to a deferred pension commencing at his Normal Retirement Date, calculated on the same basis as the retirement benefit but based on earnings and service completed to the date of termination and excluding pre-retirement indexation.. In addition, a member is also entitled to a refund of excess contributions, if any. Notwithstanding the above, a member may, in lieu of this deferred pension, elect to transfer the commuted value of the deferred pension.
Transferred Members	Each member who elected to transfer out of the Plan into the Defined Contribution Plan as of January 1, 1997, and chose to maintain their defined benefits for past service, will have their benefits calculated based on average earnings and the average YMPE for all service, including service form January 1, 1997 to the date of termination.

Appendix G

Plausible adverse scenarios

In this Appendix, the financial impact on the Plan's going concern results (i.e., going concern financial position at the valuation date), on the Plan's hypothetical wind-up and solvency financial positions at the valuation date and on the special payments of plausible adverse scenarios that would pose threats to the Plan's future financial condition is summarized in the following table for the following risks:

- Interest rate risk - an immediate parallel decrease in market interest rates of 75 basis points;
- Deterioration of asset values - an immediate decrease of 0% in the market value of non-fixed income assets; and
- Longevity risk - life expectancy from the valuation date at age 65 for a male and a female increases by 1.7 years and 1.5 years, respectively.

Scenario	Going Concern Valuation Results as at 31.12.2025	Plausible Adverse Scenario Results as at 31.12.2025		
		Interest Rate Risk	Deterioration of Asset Values	Longevity Risk
Going Concern Financial Status				
Market value of assets	$30,192,400	$33,200,000	$30,192,400	$30,192,400
Going concern funding target	$19,940,200	$21,795,500	$19,940,200	$20,816,800
Provision for Adverse Deviation	$2,058,400	$2,249,900	$2,058,400	$2,148,900
Funding excess (shortfall)	$8,193,800	$9,154,600	$8,193,800	$7,226,700

Scenario	Hypothetical Wind-Up and Solvency Position as at 31.12.2025	Plausible Adverse Scenario Results as at 31.12.2025		
		Interest Rate Risk	Deterioration of Asset Values	Longevity Risk
Hypothetical Wind-up Financial Position				
Market value of assets	$30,192,400	$33,200,000	$30,192,400	$30,192,400
Termination expense provision	($120,000)	($120,000)	($120,000)	($120,000)
Wind-up assets	$30,072,400	$33,080,000	$30,072,400	$30,072,400
Wind-up liabilities	$19,527,600	$21,267,600	$19,527,600	$20,213,800
Wind-up excess (shortfall)	$10,544,800	$11,812,400	$10,544,800	$9,858,600
Solvency Financial Position				
Reduction in wind-up liabilities due to difference in circumstances of assumed wind-up and to excluded benefits	$2,886,200	$3,306,200	$2,886,200	$3,108,800
Surplus excess (shortfall)	$13,431,000	$15,118,600	$13,431,000	$12,967,400
Solvency ratio	181%	185%	181%	177%
Transfer ratio	155%	156%	155%	149%

The balance of this Appendix provides details of the plausible adverse scenarios selected and the determination of their impact on valuation results.

Interest Rate Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's valuation results to the potential that interest rates will be lower than expected. For this purpose, we have assumed an immediate parallel decrease in market interest rates underlying fixed income investments, where fixed income investments include the following categories as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a parallel decrease in market interest rates of 75 basis points would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For purpose of this scenario, we have assumed that such a decrease in market interest rates would occur immediately on the valuation date and would have the following impact on the value of assets and going concern assumptions:

Market value of assets	The decrease in market interest rates has been assumed to affect only the market value of the fixed income investments. The decrease is assumed to have occurred immediately on the valuation date.
Discount rate assumption	Going concern: It was assumed that the decrease in market interest rates affects only the expected return on assets for the fixed income portion of assets. The discount rate assumption was therefore decreased from 4.25% to 3.50%. Hypothetical wind-up: The interest rates used in the valuation were reduced by 75 basis points Solvency: The interest rates used in the valuation were reduced by 75 basis points.
Other assumptions	Except as mentioned above, all assumptions used were the same as those used for this valuation. In particular, the discount rate used to value benefits assumed to be settled through a lump sum was not changed.
Provision for Adverse Deviations	The above changes would not affect the calculation of the Provision for Adverse Deviations

Deterioration of Asset Values

The purpose of this scenario is to illustrate the sensitivity of the Plan's valuation results to a deterioration of asset values. For this purpose, we assumed an immediate reduction in the market value of the Plan's non-fixed income assets, where non-fixed income investments include the following categories as shown in the investment policy summarized in Appendix B.

Using a methodology consistent with the one used to determine the going concern discount rate, we have determined that a decrease of 0% in the market value of value of non-fixed income assets would have a non-trivial probability (between 1 in 10 and 1 in 20) of occurring within the year following the valuation date. For purpose of this scenario, we have assumed that such a decrease would occur immediately on the valuation date and would have the following impact on the value of assets and valuation assumptions:

Market value of assets	The decrease in the market value of the non-fixed income portion of assets is assumed to have occurred immediately on the valuation date.
Going concern assumptions	This scenario is assumed to have no impact on the assumptions used for this valuation.
Wind-up & solvency assumptions	This scenario is assumed to have no impact on the assumptions used for this valuation.

Longevity Risk

The purpose of this scenario is to illustrate the sensitivity of the Plan's valuation results to the potential that pension plan members will live longer than expected. For this purpose, we have determined that a plausible adverse scenario would be to assume that future mortality improvements[7] will be in line with the average improvements experienced by the Canadian population[8] over a recent period that experienced historically high levels of improvement, with uniform improvement rates for all future years but varying by age[9] and gender.

[7] i.e. starting one year after the valuation in this context

[8] Based on Canadian population experience from the Human Mortality Database from 2002 to 2016

[9] improvement rates below age 45 are set to those at age 45

Appendix H

Employer certification

With respect to the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2025 of the Retirement Plan of Hydro One Sault Ste. Marie, I hereby certify that, to the best of my knowledge and belief:

- The valuation reflects the terms of the Company's engagement with the actuary described in Section 2 of this report, particularly the decision to not reflect a margin for adverse deviations in the going concern valuation in excess of the provision for adverse deviations prescribed by the Act. and the Company's decisions in regards to determining the going concern and solvency funding requirements.
- A copy of the official plan documents and of all amendments made up to December 31, 2025 was provided to the actuary and is reflected appropriately in the summary of plan provisions contained herein.
- The asset information summarized in Appendix B is reflective of the Plan's assets.
- The membership data provided to the actuary included a complete and accurate description of every person who is entitled to benefits under the terms of the Plan for service up to December 31, 2025.
- All events subsequent to December 31, 2025 that may have an impact on the Plan have been communicated to the actuary.

March 20, 2026
Date

Signed

Kevin Lewis
Name

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Dorothy Quinn
Hydro One Networks Inc.

20 April 2026

Subject: Projected 2026 - 2028 Pension Expense under US GAAP & IAS19

Dear Dorothy:

As requested, we have prepared an estimate of the projected pension expense for 2026 – 2028 and the related balance sheet position at each respective year end under US GAAP and IAS19 for the following plans:

- Retirement Plan of Hydro One Sault Ste. Marie LP ("Registered Plan"); and
- Hydro one Sault Ste. Marie LP Supplemental Plan ("Supplemental Plan")

The results of the projected pension expense and balance sheet position are based on the following:

- For the period from January 1 to March 31, 2026, the pension expense was calculated as the 3-month pro-rata of the FY 2026 expense presented in our ASC 715 (US GAAP) Actuarial Valuation Report as at December 31, 2025 ("US GAAP Report") and IAS 19 Actuarial Valuation Report as at December 31, 2025 ("IAS Report"). The expense for that period and the balance sheet position are presented below.
- The projection for the period after March 31, 2026 reflects HOSSM's decision to wind up the Registered Plan on April 1, 2026, resulting in **curtailment** accounting rules being applying in FY 2026. The Plan's assets and obligations were **remeasured** as of April 1, 2026 using the market value of assets and discount rates in effect at that date.
- Regulatory approval of the Registered Plan's wind-up is assumed to be obtained on March 31, 2028. The subsequent settlement of the plan obligations will trigger **settlement** accounting rules being applied in FY 2028.
- The amendment to wind up the Registered Plan includes the transfer the Supplemental Plan's obligations to the Registered Plan on March 31, 2026 and the providing of pre-retirement indexation for the Registered Plan's active members, which were reflected in the re-measured obligations. With the combination of the Supplemental Plan with the Registered Plan, the Supplemental Plan's obligations and costs are not accounted for separately over the projection period.

- Over the projection period, the March 31, 2026 market value of assets is assumed to earn an expected rate of return 3.00% per year for a 2-year horizon (based on February 28, 2026 Mercer Portfolio Return Calculator with 80% Long Term Bonds and 20% Universe Bonds target asset mix).
- Because of the Registered Plan's surplus position, no employer contributions are assumed to be made over the projection period.
- Obligations were re-measured as of April 1, 2026 using a discount rate of 5.03% per year but all other assumptions were unchanged from those used to measure the obligations as of December 31, 2025. Please see the US GAAP Report and the IAS Report for detailed information about the assumptions used.
- Membership data as at December 31, 2025 were used to re-measure obligations as of April 1, 2026. The membership data are summarized in Appendix E of the Report on the Actuarial Valuation for Funding Purposes as at December 31, 2025 ("Funding Report"). Note that the known death of a retiree in Q1 2026 with no further pension entitlement was reflected in the April 1, 2026 obligations .
- The settlement obligations as of March 31, 2028 (i.e. the assumed settlement date) has been projected from the December 31, 2025 wind-up liability presented in the HOSSM Retirement Plan – Updated Wind-up Position memo dated March 4, 2026 that was prepared by Mercer.
- Due to the closed nature of the DB provisions, we have assumed that the period used to amortize gains and losses outside of the 10% corridor (EARSL) will decrease by one year, each year in the projection period under US GAAP.
- The Registered Plan's documentation provides for the surplus that exists on the wind-up date to be shared between HOSSM and the plan members, with a greater portion being refunded to HOSSM. While HOSSM has obtained a legal opinion that the surplus sharing agreement is enforceable under the pension regulations and that the approval of the union representing the plan members has been secured ahead of proceeding with the plan wind-up, the pension regulator will have to give its approval before the surplus can be distributed (assumed to occur in 2028). Because of strict rules under IAS19, no "economic benefit" from the Registered Plan's surplus had been assumed in the IAS Report. However, with the existence of the legal opinion and the union's approval of the surplus sharing, an economic benefit equal to the surplus that is estimated to be refunded to HOSSM is being recognized under IAS19 in FY 2026. The amount of surplus assumed to be refunded to HOSSM, under both IAS19 and US GAAP on March 31, 2028 is $7,307,600[1]. This surplus amount has been estimated conservatively and could be adjusted upwards following the final settlement of the plan obligations.

[1] The surplus amount allocated to HOSSM under Step 1 of the Surplus Agreement less the obligations related to the Supplemental Plan.

2026 Projected Pension Expense - Before Curtailment (US GAAP)

Registered Plan	Jan to Mar, 2026
Projected Pension Expense	
Current service cost	0
Interest cost	228,584
Expected return on assets	(277,260)
Amortization of prior service costs	(5,735)
Amortization of (gains)/losses	(13,914)
Curtailment (gain) / loss recognized	0
Settlement (gain) / loss recognized	0
Total projected pension expense	**($68,325)**
Supplemental Plan	
Projected Pension Expense	
Current service cost	0
Interest cost	6,477
Expected return on assets	0
Amortization of prior service costs	0
Amortization of (gains)/losses	1,256
Curtailment (gain) / loss recognized	0
Settlement (gain) / loss recognized	0
Total projected pension expense	**$7,733**
Total	
Projected Pension Expense	
Current service cost	0
Interest cost	235,061
Expected return on assets	(277,260)
Amortization of prior service costs	(5,735)
Amortization of (gains)/losses	(12,658)
Curtailment (gain) / loss recognized	0
Settlement (gain) / loss recognized	0
Total projected pension expense	**($60,592)**

Projected Balance Sheet Positions at March 31 2026 - before Curtailment (USGAAP)

Registered Plan	31-Mar-26
Prior Service Cost	$0
Net gain (loss)	4,779,391
Accumulated Other Comprehensive income (loss)	**4,779,391**
Accumulated contributions in excess of the net period benefit cost	6,288,278
Net amount recognized in the statement of financial position	**$11,067,669**
Supplemental Plan	
Prior Service Cost	$0
Net gain (loss)	0
Accumulated Other Comprehensive income (loss)	**0**
Accumulated contributions in excess of the net period benefit cost	0
Net amount recognized in the statement of financial position	**$0**
Total	
Prior Service Cost	0
Net gain (loss)	4,779,391
Accumulated Other Comprehensive income (loss)	**4,779,391**
Accumulated contributions in excess of the net period benefit cost	6,288,278
Net amount recognized in the statement of financial position	**$11,067,669**

2026 to 2028 Projected Pension Expense (US GAAP)

Registered Plan	Apr - Dec 2026 (After curtailment)	2027	Jan to Mar 2028
Projected Pension Expense			
Current service cost	0	0	0
Interest cost	683,776	897,212	219,095
Expected return on assets	(656,842)	(866,339)	(213,247)
Amortization of prior service costs	0	0	0
Amortization of (gains)/losses	(61,882)	(84,009)	(21,557)
Curtailment (gain) / loss recognized	(470,260)	0	0
Settlement (gain) / loss recognized	0	0	(915,559)
Total projected pension expense	**($505,208)**	**($53,136)**	**($931,268)**

Projected Balance Sheet Positions at December 31 2026 – 2028 (USGAAP)

Registered Plan	31-Dec-26	31-Dec-27	31-Mar-2028 (before settlement)	31-Mar-2028 (after settlement)
Prior Service Cost	$0	$0	$0	$0
Net gain (loss)	4,717,508	4,633,499	4,491,942	0
Accumulated Other Comprehensive income (loss)	**4,717,508**	**4,633,499**	**4,491,942**	**0**
Accumulated contributions in excess of the net period benefit cost	6,323,225	6,376,361	6,392,070	0
Net amount recognized in the statement of financial position	**$11,040,733**	**$11,009,860**	**$10,884,012**	**$0**

2026 Projected Pension Expense - Before Curtailment (IAS 19)

Registered Plan	Jan to Mar, 2026
Projected Pension Expense	
Interest expense on DBO	228,584
Interest (income) on plan assets	(362,198)
Interest expense on effect of (asset ceiling/ onerous liability)	108,820
Adminsitrative expenses and/or taxes (not reserved within DBO)	33,750
Defined benefit cost included in P&L	**$8,956**
Remeasurements (recognized in other comprehensive income)	
Effect of changes in financial assumptions	($851,399)
Effect of experience adjustments	$0
(Return) on plan assets (excluding interest income)	$352,955
Changes in asset ceiling/onerous liability (excluding interest income)	$65,246
Total remeasurements included in OCI	**($433,199)**
Total defined benefit cost recognized in P&L and OCI	**($424,243)**
Supplemental Plan	
Projected Pension Expense	
Interest expense on DBO	6,477
Interest (income) on plan assets	0
Interest expense on effect of (asset ceiling/ onerous liability)	0
Adminsitrative expenses and/or taxes (not reserved within DBO)	0
Defined benefit cost included in P&L	**$6,477**
Remeasurements (recognized in other comprehensive income)	
Effect of changes in financial assumptions	$0
Effect of experience adjustments	($71,350)
(Return) on plan assets (excluding interest income)	$0
Changes in asset ceiling/onerous liability (excluding interest income)	$0
Total remeasurements included in OCI	**($71,350)**
Total defined benefit cost recognized in P&L and OCI	**($64,873)**
Total	
Projected Pension Expense	
Interest expense on DBO	235,061
Interest (income) on plan assets	(362,198)
Interest expense on effect of (asset ceiling/ onerous liability)	108,820
Adminsitrative expenses and/or taxes (not reserved within DBO)	33,750
Defined benefit cost included in P&L	**$15,433**
Remeasurements (recognized in other comprehensive income)	
Effect of changes in financial assumptions	($851,399)
Effect of experience adjustments	($71,350)
(Return) on plan assets (excluding interest income)	$352,955
Changes in asset ceiling/onerous liability (excluding interest income)	$65,246
Total remeasurements included in OCI	**($504,548)**
Total defined benefit cost recognized in P&L and OCI	**($489,115)**

Projected Balance Sheet Positions at March 31 2026 - before curtailment (IAS 19)

Registered Plan	31-Mar-26
Defined Benefit Obligation	$18,780,332
Fair Value of plan assets	29,848,000
Funded Status	**(11,067,668)**
Effect of Asset ceiling/onerous liability	9,039,261
Net defined benefit liability (asset)	**($2,028,407)**
Supplemental Plan	
Defined Benefit Obligation	$0
Fair Value of plan assets	0
Funded Status	0
Effect of Asset ceiling/onerous liability	0
Net defined benefit liability (asset)	**$0**
Total	
Defined Benefit Obligation	$18,780,332
Fair Value of plan assets	29,848,000
Funded Status	**(11,067,668)**
Effect of Asset ceiling/onerous liability	9,039,261
Net defined benefit liability (asset)	**($2,028,407)**

2026 to 2028 Projected Pension Expense (IAS19)

Registered Plan	2026 Apr - Dec (After curtailment)	2027	Jan to Mar 2028
Projected Pension Expense			
(Gain) / loss on settlements	0	0	3,576,383
Interest expense on DBO	683,776	897,212	219,095
Interest (income) on plan assets	(1,342,925)	(1,449,166)	(356,695)
Interest expense on effect of (asset ceiling/ onerous liability)	341,007	187,775	46,556
Adminsitrative expenses and/or taxes (not reserved within DBO)	101,250	135,000	33,750
Defined benefit cost included in P&L	**($216,892)**	**($229,179)**	**$3,519,089**
Remeasurements (recognized in other comprehensive income)			
Effect of changes in financial assumptions	$0	$0	$0
Effect of experience adjustments	$0	$0	$0
(Return) on plan assets (excluding interest income)	$584,834	$447,827	$229,698
Changes in asset ceiling/onerous liability (excluding interest income)	($5,647,163)	($218,648)	($3,748,788)
Total remeasurements included in OCI	**($5,062,329)**	**$229,179**	**($3,519,089)**
Total defined benefit cost recognized in P&L and OCI	**($5,279,221)**	**($0)**	**($0)**

Projected Balance Sheet Positions at December 31 2026 – 2028 (IAS 19)

Registered Plan	31-Dec-26	31-Dec-27	31-Mar-2028 (before settlement)	31-Mar-2028 (after settlement)
Defined Benefit Obligation	$18,492,435	$18,079,229	$17,970,238	$0
Fair Value of plan assets	29,533,168	29,089,089	28,854,250	0
Funded Status	**(11,040,733)**	**(11,009,860)**	**(10,884,012)**	**0**
Effect of Asset ceiling/onerous liability	3,733,104	3,702,231	3,576,383	0
Net defined benefit liability (asset)	**($7,307,629)**	**($7,307,629)**	**($7,307,629)**	**$0**

Please contact me should you have any questions concerning this information.

Sincerely,

Christy Kam

Christy Kam, FSA, FCIA

Principal

Copy:
Luc Girard, Mercer

Important Notices

Mercer has prepared this analysis exclusively for Hydro One Sault Ste. Marie LP to present projection of estimated expense and related balance sheet positions. This work is intended to facilitate Hydro One Sault Ste. Marie LP's decision-making relating to the December 31, 2025 accounting valuation. This information may not be used or relied upon by any other party or for any other purpose; Mercer is not responsible for the consequences of any such other use. Its content may not be modified, incorporated into or used in other material, sold or otherwise provided, in whole or in part, to any other person or entity, without Mercer's permission.

The results presented herein are estimates only and subject to change. This analysis is not a substitute for a formal valuation report.

Decisions about benefit changes, granting new benefits, investment policy, funding policy, benefit security and/or benefit-related issues should not be made solely on the basis of this preliminary valuation, but only after careful consideration of alternative economic, financial, demographic and societal factors, including financial scenarios that assume future sustained investment losses.

Hydro One Sault Ste. Marie LP is responsible for selecting the plan's accounting policies, methods and assumptions. Hydro One Sault Ste. Marie LP is responsible for communicating to Mercer any changes required to those policies, methods and assumptions.

To prepare the results in this letter, actuarial assumptions are used to model a single scenario from a range of possibilities for each valuation basis. The results based on that single scenario are included in this letter. However, the future is uncertain and the plan's actual experience will differ from those assumptions; these differences may be significant or material. Different assumptions or scenarios within the range of possibilities may also be reasonable, and results based on those assumptions would be different. Furthermore, actuarial assumptions may be changed from one valuation to the next because of changes in regulatory and professional requirements, developments in case law, plan experience, changes in expectations about the future and other factors. The assumptions used for the valuation are described in herein.

Mercer has used and relied on the membership data as supplied by Hydro One Sault Ste. Marie LP. If the data supplied are not sufficient and reliable for its intended purpose, the results of our calculation may differ significantly from the results that would be obtained with such data. Although Mercer has reviewed the suitability of the data for its intended use in accordance with accepted actuarial practice in Canada, Mercer has not verified or audited any of the data or information provided.

Mercer has used and relied on the plan documents, including amendments, and interpretations of plan provisions, supplied by Hydro One Sault Ste. Marie LP. If any plan provisions supplied are not accurate and complete, the results of any calculation may differ significantly from the results that would be obtained with accurate and complete information. Moreover, plan documents may be susceptible to different interpretations, each of which could be reasonable, and the results of estimates under each of the different interpretations could vary.

We used financial data submitted by the Hydro One Sault Ste. Marie LP as of the valuation date without further audit. Customarily, this information would not be verified by a plan's actuary. We have reviewed the information for internal consistency and general reasonableness.

CHAPTER 2 APPENDIX 2-KA: OPEBS (OTHER POST-EMPLOYMENT BENEFITS) COSTS – HOSSM

This attachment has been filed separately in MS Excel format.

1 This page has been left blank intentionally.

DEPRECIATION AND AMORTIZATION EXPENSES

1.0 INTRODUCTION

This Exhibit describes the Transmission, Distribution and Common depreciation and amortization expenses for the 2028 to 2032 test years, and outline the methodology used to determine those amounts historically and for purposes of this Application. A summary of Transmission and Distribution expenses including Depreciation, Amortization and Cloud Computing Amortization is included in Table 1.

Overall, the level of depreciation expense for the 2028 to 2032 period reflects a combination of key factors relative to the prior study, including the consistent application of the prior methodology, the addition of a new asset class (notably DER assets), and updated service life assumptions. Together, these elements result in a depreciation outlook that accurately reflects current asset conditions, operating experience, and expected replacement patterns.

Table 1 - Summary of Transmission and Distribution Expense (2028-2032)[1]

	Transmission					Distribution				
	2028	**2029**	**2030**	**2031**	**2032**	**2028**	**2029**	**2030**	**2031**	**2032**
Depreciation*	713.8	757.1	817.9	873.2	950.3	707.4	783.2	862.1	882.2	925.3
Amortization	0.4	0.4	0.4	0.4	0.4	0.3	0.3	0.3	0.3	0.3
Subtotal Expense	714.2	757.5	818.3	873.6	950.8	707.8	783.5	862.4	882.6	925.7
Amortization of Prepaid Costs Relating to Cloud Computing	24.1	48.1	55.6	44.0	46.9	46.0	85.8	102.2	93.2	100.0
Total	738.4	805.6	873.9	917.6	997.7	753.7	869.3	964.6	975.8	1,025.6

**Depreciation includes other regulatory adjustments*

[1] Figures presented in the tables may not sum to the totals shown due to rounding

1.1 TRANSMISSION BACKGROUND

The depreciation and amortization expense for Hydro One's Transmission revenue requirement applications from EB-2006-0501 for 2007 and 2008 rates through to EB-2019-0082 for 2020 to 2022 rates were supported by independent studies conducted by Foster Associates Inc. (Foster). The depreciation and amortization expense for Hydro One's Transmission revenue requirement application for 2023 to 2027 rates (EB-2021-0110), as well as for the current application, are supported by independent studies conducted by Alliance Consulting Group (Alliance).

The OEB accepted the costs flowing from each of the previous depreciation studies for the purpose of supporting Transmission revenue requirements in each of the corresponding years.

1.2 DISTRIBUTION BACKGROUND

The depreciation and amortization expense for Hydro One's Distribution revenue requirement applications from EB-2005-0020 for 2006 rates through to EB-2017-0049 for 2018 to 2022 rates were supported by independent studies conducted by Foster. The depreciation and amortization expense for Hydro One's Distribution revenue requirement application for 2023 to 2027 rates (EB-2021-0110), as well as for the current application, are supported by independent studies conducted by Alliance.

The OEB accepted the costs flowing from each of the previous depreciation studies for the purpose of supporting Distribution revenue requirements in each of the corresponding years.

1.3 COMMON BACKGROUND

The most recent depreciation rates for common assets were reviewed as part of the 2021 study by Alliance, accepted by the OEB in EB-2021-0110 and subsequently adopted for both Transmission and Distribution.

1.4 HYDRO ONE NETWORKS' TRANSMISSION, DISTRIBUTION AND COMMON DEPRECIATION PRACTICES

Hydro One Networks depreciates transmission, distribution, and common assets using established methods that reflect the consumption of asset value over time.

Major fixed assets including property, plant, and equipment and intangible assets are depreciated and amortized based on the straight-line method, incorporating the broad group procedure and the remaining life technique. Minor fixed assets are also depreciated and amortized using the straight-line method based on the remaining service life technique. However, minor assets acquired within each major category are capitalized annually as a single pooled amount.

Transport and work equipment (T&WE), however, are depreciated and amortized based on the declining balance method. This approach more accurately reflects the pattern in which the asset's service potential is consumed and better aligns their carrying value with expected resale market values over time.

1.5 APPROACH TO 2028-2032 DEPRECIATION AND AMORTIZATION EXPENSES

In 2025, Hydro One selected Alliance to prepare a new depreciation study covering Hydro One Networks' transmission, distribution and common assets for the 2028 to 2032 test years.

Alliance is a U.S. based firm that has conducted over 365 depreciation studies for regulated and non-regulated electric, gas, steam, water, wastewater, cable and communications utilities across the U.S. and Canada since 2004. In its depreciation study for Hydro One, consistent with the approach used in EB-2021-0110, Alliance has applied the average life group, broad group depreciation methodology (BG) to group the assets within each account. Alliance has advised that use of the BG methodology is consistent with depreciation practices among other North American utilities. A copy of Alliance's depreciation study is provided in Attachment 1 to this exhibit.

The following section provides a high-level comparison of the current and prior year depreciation study (EB-2021-0110), highlighting key differences in service life assumptions and their resulting impact on depreciation expense, in support of OEB filing requirements.

1.5.1 ADDITION OF 1825 ASSET CLASS TO DEPRECIATION STUDY

In accordance with Hydro One's commitment in EB-2021-0110 to conduct a depreciation study using the most recent actuals and to develop service lives for Distributed Energy Resource (DER) assets where feasible, the current study fulfills these requirements.[2] Accordingly, Alliance expanded the scope of the current study to include Asset Class 1825 - Distributed Energy Resources (DER), specifically battery storage, reflecting the addition of this asset class to Hydro One's distribution business since the previous study. As this is a new account, no previously approved service life parameters exist. Based on manufacturer expectations and input from Company subject matter experts (SME), a 20-year service life is recommended in the Alliance Study, which is consistent with service life assumptions filed by Toronto Hydro (EB-2025-0252) and Hydro Ottawa (EB-2024-0115).

1.5.2 CHANGES IN ASSET SERVICE LIVES SINCE LAST REBASING

In accordance with section 2.2.3 of the Chapter 2 Filing Requirements, distributors must explain any changes made to asset service lives since its last rebasing application. The resulting changes in service life assumptions, including the supporting rationale and associated impacts on depreciation expense, are outlined below.

1.5.2.1 TRANSMISSION

As summarized in Appendix B and C of the Alliance Study, for the Transmission segment, the average service lives of six asset classes were lengthened and three were shortened by the Study. Overall, the study indicates a 5.5% increase in 2024 depreciation expense relative to the historical 2024 expense levels derived from the prior study.

[2] See Exhibit E-08-01, Attachment 1, p. 61 and Appendix E page 2 of 3 in Alliance report

The increase in depreciation expense within the Transmission segment is primarily driven by reduced service lives for transmission station equipment (USoA 1715), which represents a high-value and critical component of the system. The decline in average life from 48 to 43 years is supported by observed operational evidence, including increased loading, aging of key components, and ongoing technological changes in substation equipment. Although the percentage increase in depreciation rates is modest (1.93% to 2.21%), the significant asset balance within this account contributes to a meaningful increase in annual depreciation expense (increasing the overall Tx depreciation by 8.9%).

This increase is offset by a decrease in depreciation expense driven by an extension of service lives for communication equipment (USoA 1955). The increase in average life from 20 to 24 years is supported by Company SME input and component-level analysis, which indicate longer expected operational lives for telecom, fiber, and related communication infrastructure. Although retirement activity for this account remains limited, improvements in technology, asset durability, and network design have contributed to more stable performance and extended replacement cycles. The significant asset balance within this account contributes to a meaningful decrease in annual depreciation expense (decreasing the overall Tx depreciation by 2.8%).

1.5.2.2 DISTRIBUTION

As summarized in Appendix B and C of the Alliance Study, for the Distribution segment, the average service lives of five asset classes were lengthened and three were shortened by the Study. Overall, the study indicates a 5.0% decrease in 2024 depreciation expense relative to the historical 2024 expense levels derived from the prior study.

The decrease in depreciation expense within the Distribution segment is primarily driven by an increase in the service life of poles, towers, and fixtures (USoA 1830). The average life was extended from 55 to 60 years to take into consideration the implementation of pole testing and treatment programs and improved maintenance practices. These factors support longer asset durability and extend operational lives. The large asset base results

in significant decrease in annual depreciation expense (decreasing the overall Dx depreciation by 2.0%).

This decrease in depreciation expense is also driven by an extension of service lives for communication equipment (Account 1955). The increase in average life from 7 to 10 years is supported by Company SME input and component-level analysis, which indicate longer expected operational lives. The large asset base results in a significant decrease in annual depreciation expense (decreasing the overall Dx depreciation by 1.4%).

The decrease in depreciation expense is also driven by a reduction in the service life of first-generation smart meters (USoA 1555), which declined from 18 to 13 years. This change is supported by observed field performance, including early failures and accelerated technological obsolescence. At the same time, the deployment of second-generation smart meters with longer expected service lives (USoA 1860) partially offsets this impact. However, given the large installed base of first-generation meters still in service, the net effect decreases annual depreciation expense (decreasing the overall Dx depreciation by 1.3%).

1.5.2.3 COMMON

As summarized in Appendix B and C of the Alliance Study, for the Common segment, the average service lives of two asset classes were lengthened and one was shortened by the Study. Overall, the study indicates a 35.5% increase in 2024 depreciation expense relative to the historical 2024 expense levels derived from the prior study.

The increase in depreciation within the Common segment is primarily driven by shorter service lives for computer software (USoA 1610), which declined from 12 years to 10 years. This change reflects faster technology turnover, more frequent upgrade cycles, and known system lifecycles such as the retirement of major platforms (e.g., SAP). As a result, depreciation rates increase (from 8.33% to 11.76%) to ensure that costs are recovered over the assets' actual useful lives and aligned with observed technology obsolescence

patterns. The large asset base results in a significant increase in annual depreciation expense (increasing the overall common depreciation by 22.3%).

1.5.3 COMPARISON OF DEPRECIATION STUDY AND KINECTRICS ASSET SERVICE LIVES

In accordance with section 2.2.3 of the Chapter 2 Filing Requirements, distributors are required to demonstrate that their proposed depreciation and amortization expenses appropriately reflect the useful lives of their assets and align with OEB policy. Where proposed service lives fall outside the ranges outlined in the Kinectrics Study, distributors must provide clear justification and supporting evidence to demonstrate that the underlying assumptions are reasonable.

The Chapter 2 Appendix 2-BB for the Transmission and Distribution segment identifies several asset classes for which service lives derived from the Alliance study fall outside the ranges established in the Kinectrics study.

The Kinectrics Study was completed in 2010 and reflects assumptions, operating conditions, asset performance data, maintenance practices, technology, and replacement strategies that existed more than fifteen years ago. Since that time, significant changes have occurred across the electricity industry that may materially influence asset service lives, including:

- advancements in asset design, materials, and manufacturing quality that may extend the life expectancy of certain assets;
- changes in maintenance programs, condition monitoring capabilities, and asset health analytics, allowing assets to remain in service longer than previously anticipated;
- evolving operational requirements, system loading patterns, and environmental conditions that may accelerate or delay asset retirement decisions;
- changes in regulatory requirements, safety standards, and reliability expectations that can affect replacement timing independent of physical deterioration; and

- the availability of a substantially larger and more recent asset history from which to assess retirement patterns and estimate service lives.

Hydro One notes that the Alliance Study was based on current asset data, historical retirement experience, and an evaluation of the Company's specific circumstances and asset population. As a result, the service life estimates developed in the Alliance Study reflect the most recent evidence available regarding the expected useful lives of the Company's assets.

Alliance has removed references to the Kinectrics service life ranges from its final study, as the Kinectrics ranges were not used as the basis for determining the recommended service lives. Rather, the recommended service lives were derived from an analysis of the Company’s actual asset characteristics, retirement behavior, operating environment, and current expectations regarding future asset utilization.

Accordingly, despite the fact that certain Alliance Study service lives fall outside ranges identified in a study completed in 2010, the more relevant consideration is whether the proposed service lives are supported by current empirical evidence and reflect the best estimate of the remaining useful lives of the Company's assets. The Alliance Study provides that support through its use of recent asset information and industry-standard depreciation methodologies.

2.0 DEPRECIATION EXPENSE

Tables 2 and 3, below, present each of the elements required to determine Hydro One’s proposed depreciation expenses for Transmission and Distribution over the 2023 to 2032 period, which include the 2023 to 2025 historical period[3], the 2026 to 2027 bridge years, and the 2028 to 2032 test years.

These elements include (a) Depreciation on Fixed Assets, which for the test years is based on the results from the new Alliance Depreciation Study, (b) Capitalized Depreciation, (c)

[3] 2026 is provided on a forecast basis

Asset Removal Costs, and (d) Losses/Gains on Asset Disposition. Each of these elements is discussed below.

Detailed depreciation schedules are filed at Attachment 2 to this exhibit.

Table 2 - Transmission Depreciation Expense ($M)[4]

	Historical Actuals									Bridge						Test Years				
	2023			2024			2025			2026			2027			2028	2029	2030	2031	2032
Transmission	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**
Depreciation On Fixed Assets	458.9	481.1	(22.2)	486.9	506.9	(20.0)	511.9	533.8	(21.9)	541.0	560.4	(19.4)	567.9	584.3	(16.4)	659.8	709.1	750.6	798.2	889.9
Less Capitalized Depreciation	(15.6)	(14.8)	(0.8)	(13.5)	(14.9)	1.4	(16.1)	(15.1)	(1.0)	(15.8)	(15.2)	(0.6)	(16.6)	(15.3)	(1.3)	(17.2)	(19.0)	(20.7)	(22.9)	(24.3)
Asset Removal Costs	58.3	57.4	0.9	56.9	59.2	(2.3)	52.8	66.1	(13.3)	73.0	68.9	4.1	64.4	65.8	(1.4)	71.2	67.1	87.9	97.9	84.7
Losses/(Gains) On Asset Disposition	0.4	-	0.4	(0.2)	-	(0.2)	(1.2)	-	(1.2)	-	-	-	-	-	-	-	-	-	-	-
Total	**502.1**	**523.7**	**(21.6)**	**530.0**	**551.2**	**(21.2)**	**547.4**	**584.8**	**(37.4)**	**598.2**	**614.1**	**(15.9)**	**615.7**	**634.8**	**(19.1)**	**713.8**	**757.1**	**817.9**	**873.2**	**950.3**
Exclude Other Reg Adjustment	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Adjusted Total	**502.1**	**523.7**	**(21.6)**	**530.0**	**551.2**	**(21.2)**	**547.4**	**584.8**	**(37.4)**	**598.2**	**614.1**	**(15.9)**	**615.7**	**634.8**	**(19.1)**	**713.8**	**757.1**	**817.9**	**873.2**	**950.3**

[4] Figures presented in the tables may not sum to the totals shown due to rounding

Witness: Anthony Nava

Table 3 - Distribution Depreciation Expense ($M)* [5]

	Historical Actuals									Bridge						Test Years				
	2023			2024			2025			2026			2027			2028	2029	2030	2031	2032
Distribution	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**
Depreciation On Fixed Assets	402.3	405.7	(3.4)	426.0	425.9	0.1	457.1	459.1	(2.0)	488.9	492.4	(3.5)	527.3	522.0	5.3	591.9	646.0	683.7	732.5	774.7
Less Capitalized Depreciation	(17.7)	(18.2)	0.5	(18.8)	(18.3)	(0.5)	(19.4)	(18.5)	(0.9)	(21.5)	(18.7)	(2.8)	(22.6)	(18.9)	(3.7)	(23.4)	(25.9)	(28.3)	(31.6)	(33.5)
Asset Removal Costs	68.9	72.1	(3.2)	87.4	72.0	15.4	86.9	77.0	9.9	89.3	76.1	13.2	92.3	79.4	12.9	143.2	167.8	212.0	187.2	190.6
Losses/(Gains) On Asset Disposition	(1.1)	-	(1.1)	(0.5)	-	(0.5)	(2.3)	-	(2.3)	-	-	-	-	-	-	-	-	-	-	-
Total	**452.4**	**459.6**	**(7.2)**	**494.0**	**479.6**	**14.4**	**522.2**	**517.6**	**4.6**	**556.7**	**549.8**	**6.9**	**596.9**	**582.5**	**14.4**	**711.7**	**787.8**	**867.3**	**888.1**	**931.8**
Exclude Other Reg Adjustment	3.5	0	3.5	3.3	0	3.3	3.6	0	3.6	3.8	0	3.8	3.9	0	3.9	4.2	4.7	5.2	5.9	6.5
Adjusted Total	**448.9**	**459.6**	**(10.7)**	**490.7**	**479.6**	**11.1**	**518.6**	**517.6**	**1.0**	**552.9**	**549.8**	**3.1**	**592.9**	**582.5**	**10.4**	**707.5**	**783.2**	**862.1**	**882.2**	**925.3**

**Note 1: 2023-2030 figures refer only to Hydro One Distribution, excluding Acquired Utilities (Peterborough and Orillia). 2031-2032 figures refer to Hydro One Distribution including Acquired Utilities (Peterborough and Orillia)*

[5] Figures presented in the tables may not sum to the totals shown due to rounding

Witness: Anthony Nava

2.1 DEPRECIATION ON FIXED ASSETS

Hydro One has historically employed the half-year rule in calculating its depreciation expense for in-service additions and has continued this practice for test years. Depreciation rates are periodically reviewed by an external, independent fixed asset actuary and changes in depreciation rates are reflected for accounting purposes prospectively, consistent with their inclusion in electricity rates and subject to approval by the OEB. As noted above, Alliance has been retained to develop the proposed depreciation rates for Hydro One's Transmission, Distribution and Common Assets for the test period.

For costs relating to common assets, which are not directly attributable to the Transmission and Distribution businesses, Hydro One adopted, and has consistently applied, the OEB-approved Shared Asset allocation methodology as detailed in Exhibit C-03-01. Depreciation and amortization expenses are calculated for the Transmission and Distribution businesses based on asset allocation which uses the Shared Asset methodology for cost allocation.

In addition to the factors outlined in section 1.5, the increase in 2028 depreciation expense on Transmission and Distribution fixed assets relative to the 2027 is primarily driven by a higher level of assets in service, resulting in a larger depreciable asset base.

2.2 CAPITALIZED DEPRECIATION

Capitalized depreciation refers to depreciation of transport and work equipment, as well as other minor fixed assets (e.g. tools) that are charged to capital work projects. As such depreciation is treated as a capital expenditure, and it is deducted from the annual depreciation expense. This treatment prevents the recognition of depreciation both within capital project costs and as a period expense, thereby avoiding duplication.

2.3 ASSET REMOVAL COSTS

Fixed asset removal costs are grouped with depreciation expense and are recorded on an "as incurred" basis. These consist of the costs associated with removing old assets, such as the costs of digging up old foundations or removing old equipment.

Asset removal costs are included as a component of Hydro One's depreciation expense because, in an income statement, components are either classified by their nature or by their function. To report expenses by function means to report them according to the activity for which the expenses were incurred. The income statement will report expenses according to the following functional classifications: cost of power; operations, maintenance and administration; depreciation and amortization; and financing. This requires grouping similar expenses. Accordingly, asset removal costs are grouped together with depreciation and amortization due to their similar characteristics.

Most fixed asset removal costs are labour and equipment costs, rather than costs for materials. For both the Transmission and Distribution businesses, removal costs are driven by the nature and timing of work. System Renewal work, which is driven by assets needs and customer outcomes, drives most of these expenditures.

In EB-2021-0110, the OEB approved Hydro One's proposal to continue using the Transmission Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account, as well as to establish an equivalent new account for Distribution. Please refer to Exhibit G-01-01, sections 3.16 and 6.8, for discussion on the currently approved Depreciation Expense (Asset Removal Costs) Asymmetrical Cumulative Variance Account in respect of Transmission and Distribution.

For the 2028-2032 test years, Hydro One is proposing to continue the account for Transmission (with modification) and discontinue the account for Distribution. Please refer to Exhibit G-01-03, sections 3.6 and 8.21, for the requests.

2.4 LOSSES/GAINS ON ASSET DISPOSITION

Losses/gains on asset disposition relate to the sale of assets. Losses/gains on asset disposition are based on historical actuals and are not forecasted for the bridge or test years. Hydro One has not historically recognized significant gains or losses as the company does not focus substantial efforts on selling assets as part of its normal course of business.

3.0 AMORTIZATION EXPENSE

Amortization expenses pertain to certain regulatory amounts for which the OEB has allowed Hydro One Transmission and Distribution to defer recovery until a future date. More particularly, Hydro One estimates its future Transmission and Distribution expenditures that are required to remediate past environmental contamination and to comply with current environmental legislation. Since these future expenditures are expected to be recovered in future rates, Hydro One has recognized the net present value of these estimated future expenditures as a regulatory asset on its balance sheet.

Hydro One Distribution first received approval from the OEB for this accounting treatment as part of the RP-2000-0023 Decision, and it has continued to be accepted in subsequent Distribution applications by the OEB. Hydro One Transmission's treatment of these costs was first presented in its Application for 2007-2008 Transmission Rates in EB-2006-0501, consistent with the Distribution treatment discussed above, and was accepted by the OEB in that proceeding and in subsequent applications. The proposed treatment of these costs in the current Application is consistent with the treatment afforded in these prior Distribution and Transmission proceedings.

3.1 ENVIRONMENTAL ASSETS AND OTHER

The environmental regulatory asset balance is amortized on a basis consistent with the pattern of current expenditures. The combined work program manages the removal and replacement of polychlorinated biphenyls (PCBs) contaminated equipment and Hydro One's Land Assessment and Remediation (LAR) program. The Dx PCB portion of the program is expected to be closed by Environment Canada at the end of 2026.

Amortization schedules for test, bridge and historical years[6] are filed at Exhibit E-08-01 Attachment 2. Tables 4 and 5, below, reproduce the summary for Transmission and Distribution.

[6] 2026 is provided on a forecast basis.

Table 4 - Transmission Amortization Expense ($M)

	Historical Actuals									Bridge						Test Years				
	2023			2024			2025			2026			2027			2028	2029	2030	2031	2032
Transmission	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**
Environmental Assets and Other	7.2	7.6	(0.4)	4.5	7.5	(3.0)	1.3	6.6	(5.3)	0.4	0.0	0.4	0.4	0.0	0.4	0.4	0.4	0.4	0.4	0.4

Table 5 - Distribution Amortization Expense ($M)

	Historical Actuals									Bridge						Test Years				
	2023			2024			2025			2026			2027			2028	2029	2030	2031	2032
Distribution	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Actual**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**OEB-App.**	**Diff.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**	**Fcst.**
Environmental Assets and Other	4.8	5.5	(0.7)	5.3	5.4	(0.1)	0.4	1.0	(0.6)	0.5	0.0	0.5	0.5	0.0	0.5	0.3	0.3	0.3	0.3	0.3

4.0 OVERVIEW OF CLOUD COMPUTING IMPLEMENTATION COST ACCOUNTING STANDARD

Hydro One accounts for cloud computing implementation costs in accordance with U.S. GAAP, specifically ASC 350-40, *Internal-Use Software*. Under this guidance, cloud computing arrangements that are classified as service contracts, such as Software-as-a-Service (SaaS), require entities to capitalize implementation costs to the balance sheet as a prepaid expense. Capitalized implementation costs include costs for activities related to application configuration, coding, integration, and the testing of cloud computing solutions. These costs represent the effort required to prepare the cloud computing solution for its intended operational use. Capitalized implementation costs create future economic benefits through enhanced system functionality and improved capability. These costs are recorded as a non-current and current asset ("prepaid") on the balance sheet and are amortized as an expense on a straight-line basis over the length of the cloud service arrangement, including reasonable renewal options.

Consistent with ASC 350-40, cloud subscription service costs, training, data conversion, and business reengineering costs are expensed as incurred.

Hydro One has found that, on average, the amortization period for implementation costs is approximately three years, so for the purpose of forecasting the bridge years (2026-2027) and test years (2028-2032) the capitalized implementation costs that are put into operation will be amortized over three years.

Table 6 - Continuity Schedule of Prepaid Costs Related to Cloud Computing for Transmission ($M)[7]

Transmission	Historical Actuals			Bridge		Test Years				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Prepaid Cloud Opening	0	0	15.0	14.1	53.2	79.3	125.8	144.7	160.1	174.7
Additions	0	17.8	4.0	46.3	31.3	68.3	63.0	67.8	56.3	42.5
Amortization	0	(2.8)	(4.8)	(7.3)	(5.2)	(21.8)	(44.1)	(52.4)	(41.7)	(43.1)
Prepaid Cloud Ending	**0**	**15.0**	**14.1**	**53.2**	**79.3**	**125.8**	**144.7**	**160.1**	**174.7**	**174.0**
In-Progress Projects	0	5.9	4.9	47.9	71.3	29.5	66.7	99.9	137.0	54.3
Implemented Projects	0	9.1	9.2	5.3	8.0	96.4	78.0	60.2	37.7	119.8
Total Cloud Prepaid	**0**	**15.0**	**14.1**	**53.2**	**79.3**	**125.8**	**144.7**	**160.1**	**174.7**	**174.0**

Table 7 - Continuity Schedule of Prepaid Costs Related to Cloud Computing for Distribution ($M)[8]

Distribution	Historical Actuals			Bridge		Test Years				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Prepaid Cloud Opening	0	0	28.9	44.3	106.2	138.2	199.8	261.6	290.9	309.5
Additions	0	32.2	22.7	76.2	48.4	103.0	140.5	125.1	106.7	99.9
Amortization	0	(3.3)	(7.3)	(14.3)	(16.4)	(41.5)	(78.7)	(95.8)	(88.0)	(92.3)
Prepaid Cloud Ending	**0**	**28.9**	**44.3**	**106.2**	**138.2**	**199.8**	**261.6**	**290.9**	**309.5**	**317.1**
In-Progress Projects	0	17.3	10.5	65.0	99.4	40.6	111.9	162.9	214.5	90.2
Implemented Projects	0	11.6	33.8	41.2	38.8	159.2	149.7	127.9	95.0	227.0
Total Cloud Prepaid	**0**	**28.9**	**44.3**	**106.2**	**138.2**	**199.8**	**261.6**	**290.9**	**309.5**	**317.1**

[7] Figures presented in the tables may not sum to the totals shown due to rounding
[8] Figures presented in the tables may not sum to the totals shown due to rounding

Table 8 - Amortized Expense Relating to Prepaid Cloud Computing for Transmission ($M)

Transmission	Historical Actuals			Bridge		Test Years				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Amortized Expense	0	2.8	4.8	7.3	5.2	21.8	44.1	52.4	41.7	43.1

Table 9 - Amortized Expense Relating to Prepaid Cloud Computing for Distribution ($M)

Distribution	Historical Actuals			Bridge		Test Years				
	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Amortized Expense	0	3.3	7.3	14.3	16.4	41.5	78.7	95.8	88.0	92.3

4.1 PROPOSED REGULATORY TREATMENT FOR CLOUD COMPUTING IMPLEMENTATION COSTS

For the 2028-2032 test years, Hydro One proposes a revenue requirement structure for cloud computing implementation cost as follows:

- Apply the applicable long-term debt rate for Transmission and Distribution on the forecasted mid-year average balance of the unamortized capitalized cloud computing implementation costs on cloud solutions that are put into operational use.
- Include amortized implementation costs in the revenue requirement calculation.

The proposed revenue requirement structure will provide Hydro One with a return that takes into consideration the time it takes for the implementation cost of an operational solution to be fully amortized as an expense.

Table 10 - Cloud Computing Implementation Cost Continuity Schedule for Transmission[9]

Transmission	Test Years				
	2028	**2029**	**2030**	**2031**	**2032**
Opening Prepaid (Implemented)	8.0	96.4	78.0	60.2	37.7
Ending Prepaid (Implemented)	96.4	78.0	60.2	37.7	119.8
Mid-Year Average [A]	**52.2**	**87.2**	**69.1**	**49.0**	**78.8**
Long-Term Debt Rate [B]	**4.52%**	**4.57%**	**4.61%**	**4.70%**	**4.76%**
Revenue Requirement – Prepaid [C = A x B]	**2.3**	**4.0**	**3.2**	**2.3**	**3.8**
Revenue Requirement – Expense [D]	21.8	44.1	52.4	41.7	43.1
Total Revenue Requirement [C + D]	**24.1**	**48.1**	**55.6**	**44.0**	**46.9**

Table 11 - Cloud Computing Implementation Cost Continuity Schedule for Distribution[9]

Distribution	Test Years				
	2028	**2029**	**2030**	**2031**	**2032**
Opening Prepaid (Implemented)	38.8	159.2	149.7	127.9	95.0
Ending Prepaid (Implemented)	159.2	149.7	127.9	95.0	227.0
Mid-Year Average [A]	**99.0**	**154.5**	**138.8**	**111.5**	**161.0**
Long-Term Debt Rate [B]	**4.51%**	**4.57%**	**4.62%**	**4.70%**	**4.75%**
Revenue Requirement – Prepaid [C = A x B]	**4.5**	**7.1**	**6.4**	**5.2**	**7.6**
Revenue Requirement – Expense [D]	41.5	78.7	95.8	88.0	92.3
Total Revenue Requirement [C + D]	**46.0**	**85.8**	**102.2**	**93.2**	**100.0**

[9] Figures presented in the tables may not sum to the totals shown due to rounding

HYDRO ONE NETWORKS INC.

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

BU 210, 220, AND 300

TRANSMISSION, DISTRIBUTION,

AND COMMON BUSINESS UNITS

AT DECEMBER 31, 2024

August 2026

http://www.utilityalliance.com

HYDRO ONE NETWORKS INC.
ELECTRIC UTILITY PLANT
DEPRECIATION RATE STUDY
EXECUTIVE SUMMARY
BU 210, 220, AND 300

TRANSMISSION, DISTRIBUTION,
AND COMMON BUSINESS UNITS
AT DECEMBER 31, 2024

Hydro One Networks Inc. ("Hydro One" or the "Company"), engaged Alliance Consulting Group ("Alliance") to conduct a depreciation study of the Company's electric utility plant depreciable assets as of December 31, 2024.

This study proposes depreciation accrual rates based on year end 2024 data that will be applied to plant balances developed in connection with a joint transmission and distribution Custom Incentive Rate ("CIR") application that will be filed with the Ontario Energy Board ("OEB") for purposes of establishing Hydro One's transmission revenue requirement and distribution rates for the 2028-2032 period (the "Joint Application"). For illustrative purposes, the tables below show the impact of the proposed depreciation accrual rates when applied to Hydro One's 2024 fixed asset values but do not reflect the changes that will occur for periods 2028 forward, which will be calculated once the rate application is prepared. Based on 2024 year-end values, which will differ from depreciation expense amounts in the filed application, this study would result in an overall increase of $38.0 million in annual depreciation expenses for all accounts when using the proposed depreciation rates. This is in comparison to the existing annual depreciation accrual without including the existing true-up. A summary comparison of annual accrual by utility function is shown below. These amounts will differ from those computed in the CIR application when applied to 2028-2032 plant balances.

BU 210 Transmission Operations

Function	Plant at 12/31/2024	Existing Accrual	Proposed Accrual	Difference
Intangible	113,475,266	11,347,527	11,362,689	15,162
Transmission	21,391,629,679	364,415,404	401,052,567	36,637,163
General Depreciated	1,371,916,313	48,796,190	35,485,629	(13,310,561)
General Amortized	8,563,319	1,427,220	1,427,220	0
Total	22,885,584,577	425,986,340	449,328,104	23,341,764

BU 220 Distribution Operations

Function	Plant at 12/31/2024	Existing Accrual	Proposed Accrual	Difference
Intangible	346,622,280	34,662,228	36,911,984	2,249,756
Distribution	13,952,732,063	295,660,213	282,210,612	(13,449,601)
General Depreciated	469,161,107	10,956,798	5,082,625	(5,874,173)
General Amortized	2,405,503	400,917	400,917	0
Total	14,770,920,953	341,680,156	324,606,138	(17,074,018)

BU 300 Common Operations

Function	Plant at 12/31/2024	Existing Accrual	Proposed Accrual	Difference
Intangible	580,288,962	48,338,071	68,248,688	19,910,617
General Depreciated	453,721,587	11,355,639	23,144,508	11,788,869
General Amortized	154,507,223	29,658,770	29,658,770	0
Total	1,188,517,772	89,352,480	121,051,966	31,699,486

Total Hydro One	38,815,023,302	857,018,976	894,986,208	37,967,232

Appendix A shows the computation of depreciation rates based on 2024 year-end investment, and Appendix B shows a detailed comparison of the approved versus proposed depreciation rates and annual accruals by account for each utility function.

HYDRO ONE NETWORKS INC.

ELECTRIC UTILITY PLANT

DEPRECIATION RATE STUDY

BU 210, 220, AND 300

TRANSMISSION, DISTRIBUTION,

AND COMMON BUSINESS UNITS

AT DECEMBER 31, 2024

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PURPOSE

This review provides the foundation and documentation for recommended changes in the depreciation accrual rates used by Hydro One Networks for its Transmission and Distribution Operations. The recommended rates are subject to acceptance by the Ontario Energy Board. Hydro One plant data through December 31, 2024 was used to compute the proposed depreciation rates. These proposed rates are being used to establish proposed transmission and distribution revenue requirements in the Joint Application for 2028-2032. In the Joint Application, these rates, which are based on 2024, will be applied to the 2028-2032 investment balances. The account-based depreciation rates were designed to recover the total remaining undepreciated investment over the remaining life of Hydro One's property on a straight-line basis. Land and other non-depreciable property were excluded from this study.

Hydro One is Ontario's largest electricity transmission and distribution service provider. Hydro One distributes electricity across Ontario to nearly 1.5 million customers, or approximately 26 percent of the total numbers of customers in Ontario. Hydro One's transmission system accounts for approximately 98 percent of Ontario's electricity transmission capacity.

Hydro One Inc. ("HOI") has been in existence since 1999 and is the successor company to Ontario Hydro's electricity transmission and distribution businesses. Hydro One Limited ("HOL") was incorporated on August 31, 2015 under the Business Corporations Act (Ontario). On October 31, 2015, HOL acquired HOI, a company previously wholly owned by the Province of Ontario (the "Province"). At December 31, 2024, the Province held approximately 47.1 percent of the common shares of HOL. The principal businesses of HOL, which it carries out primarily through Hydro One Networks Inc., are the transmission and distribution of electricity to customers within Ontario.

STUDY RESULTS

Overall depreciation rates for all Hydro One depreciable property are shown in Appendix A. The amount of the change in depreciation expense in the application will depend on application of the depreciation rates established in this report to Hydro One's total forecast depreciable investment levels for that year. For illustrative purposes, a comparison is given based on data at year end 2024. These rates translate into an annual depreciation accrual of $895.0 million based on Hydro One's depreciable investment at December 31, 2024. The annual equivalent depreciation expense calculated by the same method using the approved rates was $857.0 million, resulting in a $38.0 million increase in annual depreciation expense. Appendix A presents the calculation of the annual depreciation rates and resulting accrual. Appendix B presents a comparison of approved versus proposed rates and annual accruals by account. Appendix C presents a summary of life and mortality curve parameters by account. Appendix D presents a summary of book depreciation reserve as compared to the reallocated depreciation reserve for each business unit. Appendix E presents a summary of estimated component life for each plant account within Hydro One. Finally, Appendix F provides information on the background and qualifications of Alliance Consulting Group.

GENERAL DISCUSSION

Definition

The term "depreciation" as used in this study is considered in the accounting sense; that is, a system of accounting that distributes the cost of assets, less net salvage (if any), over the estimated useful life of the assets in a systematic and rational manner. It is a process of allocation, not valuation. This expense is systematically allocated to accounting periods over the life of the properties. The amount allocated to any one accounting period does not necessarily represent the loss or decrease in value that will occur during that particular period. The Company accrues depreciation on the basis of the original cost of all depreciable property included in each functional property group. On retirement, the full cost of depreciable property, less the net salvage value, is charged to the depreciation reserve.

Basis of Depreciation Estimates

For all depreciable accounts, the straight-line, broad (average) life group, remaining-life depreciation system was employed to calculate annual and accrued depreciation in this study. In this system, the annual depreciation expense for each group is computed by dividing the original cost of the asset less allocated depreciation reserve less estimated net salvage by its respective average life group remaining life. The resulting annual accrual amounts of all depreciable property within a function were accumulated, and the total was divided by the original cost of all functional depreciable property to determine the depreciation rate. The calculated remaining lives and annual depreciation accrual rates were based on attained ages of plant in service and the estimated service life and salvage characteristics of each depreciable group.

The advantage of the broad group system is that all assets within an account are considered to be one group. Broad group depreciation is widely used and produces stable depreciation rates from year to year because of its averaging effects. The broad group procedure “requires the least accounting records of annual

additions and balances."[1] While other depreciation procedures, such as vintage group or equal life group methods, could be considered, the Company continues to apply the depreciation approach approved in its previous study; the straight line, broad group, remaining life methodology. This study represents the second depreciation proceeding in which the Company has applied the broad group procedure. This system provides the stability of the broad group procedure and the accuracy of the remaining life technique, while complying with straight-line depreciation requirements. It is also the predominant system used across the utility industry. The computations of the annual functional depreciation rates are shown in Appendix A.

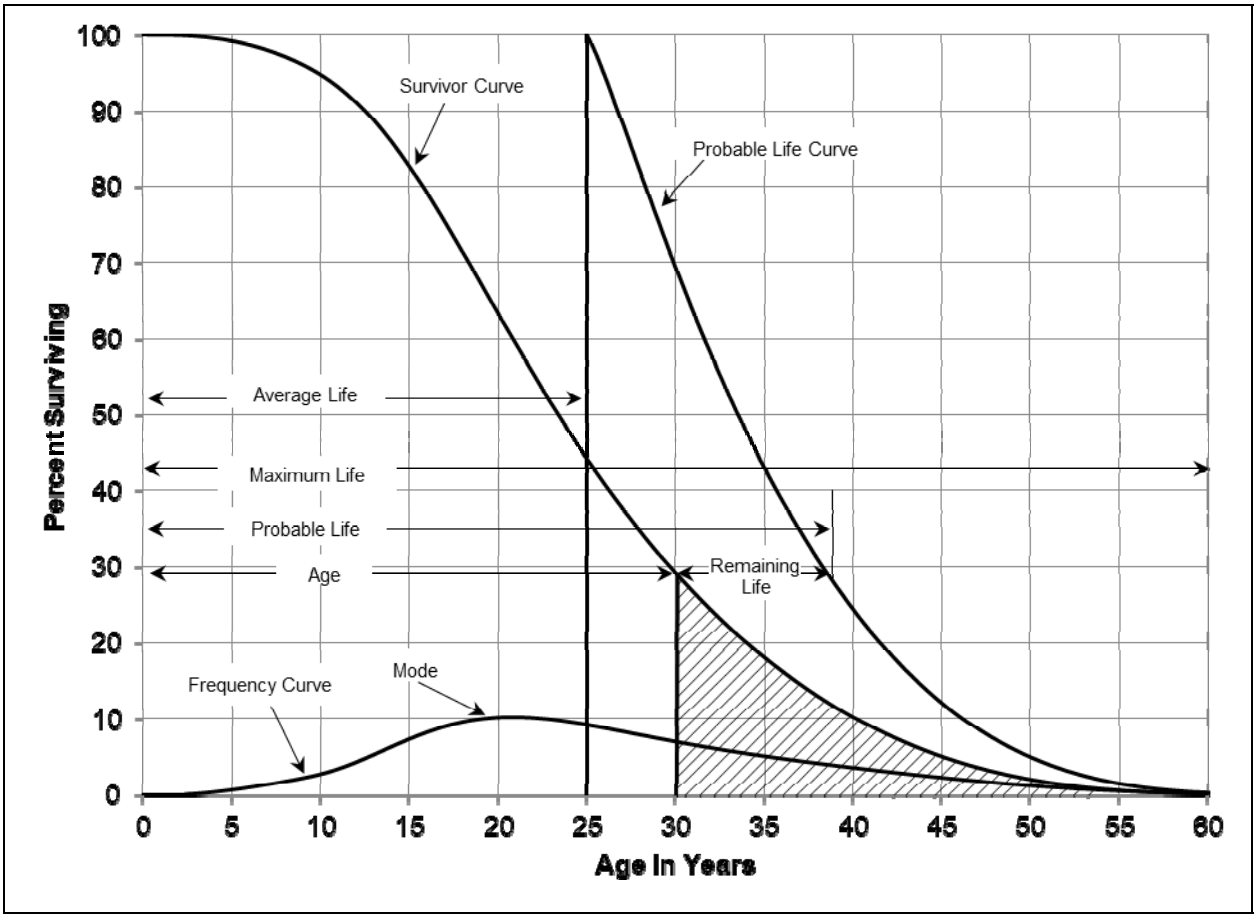
Actuarial analysis was used with each account within a function where sufficient data was available, and professional judgment was used to some degree on all accounts.

[1] Public Utility Depreciation Practices, National Association of Regulatory Utility Commissioners, 1996, p. 62.

Survivor Curves

To fully understand depreciation projections in a regulated utility setting, there must be a basic understanding of survivor curves. Individual property units within a group do not normally have identical lives or investment amounts. The average life of a group can be determined by first constructing a survivor curve which is plotted as a percentage of the units surviving at each age. A survivor curve represents the percentage of property remaining in service at various age intervals. The chart below shows a typical generalized survivor curve as well as some of the life characteristics that can be derived from the survivor curve.

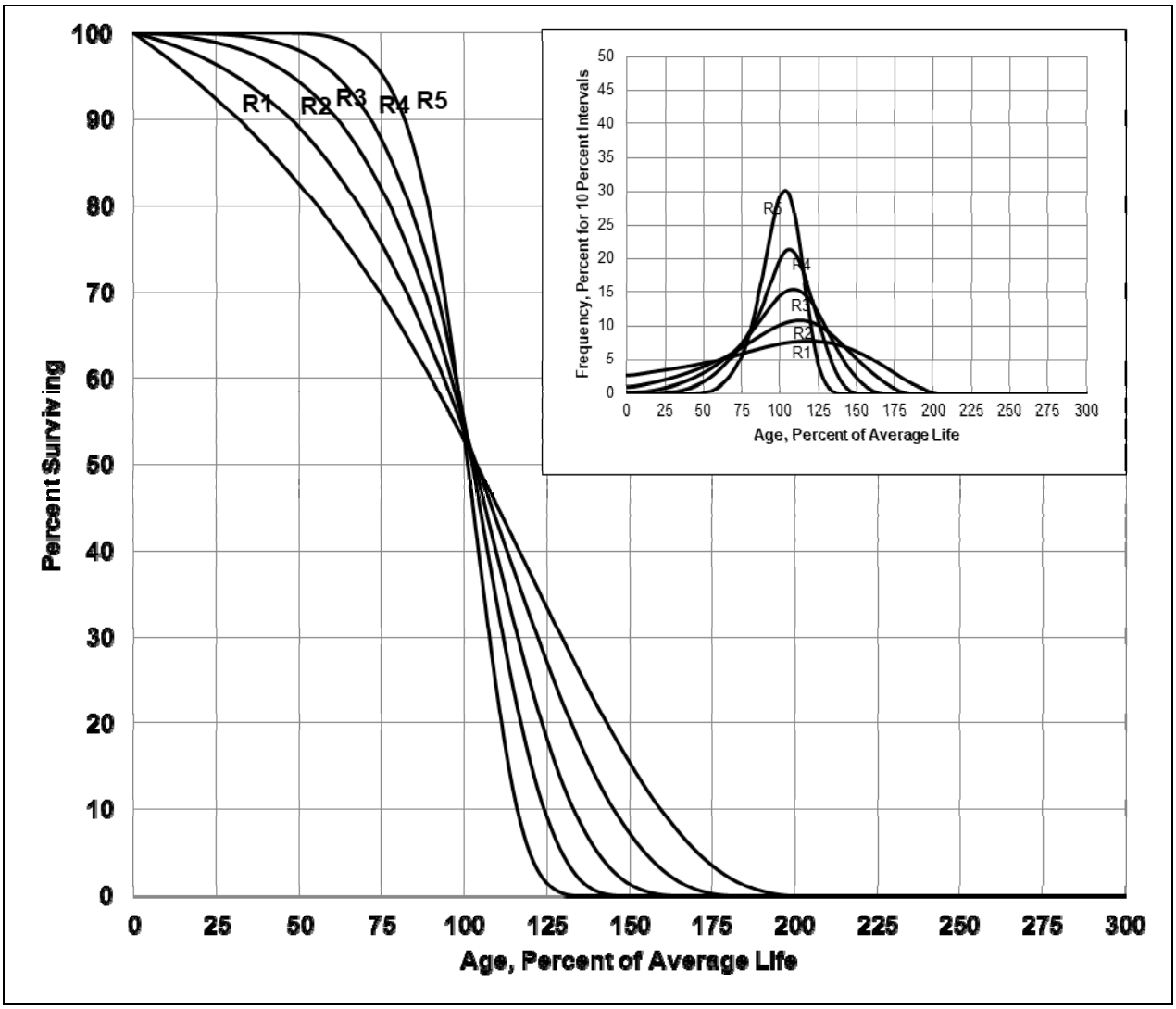
GENERALIZED SURVIVOR CURVE



The Iowa Curves are the result of an extensive investigation of life characteristics of physical property made at Iowa State College Engineering Experiment Station in the first half of the prior century. Through common usage, revalidation and regulatory acceptance, these curves have become a descriptive standard for the life characteristics of industrial property.

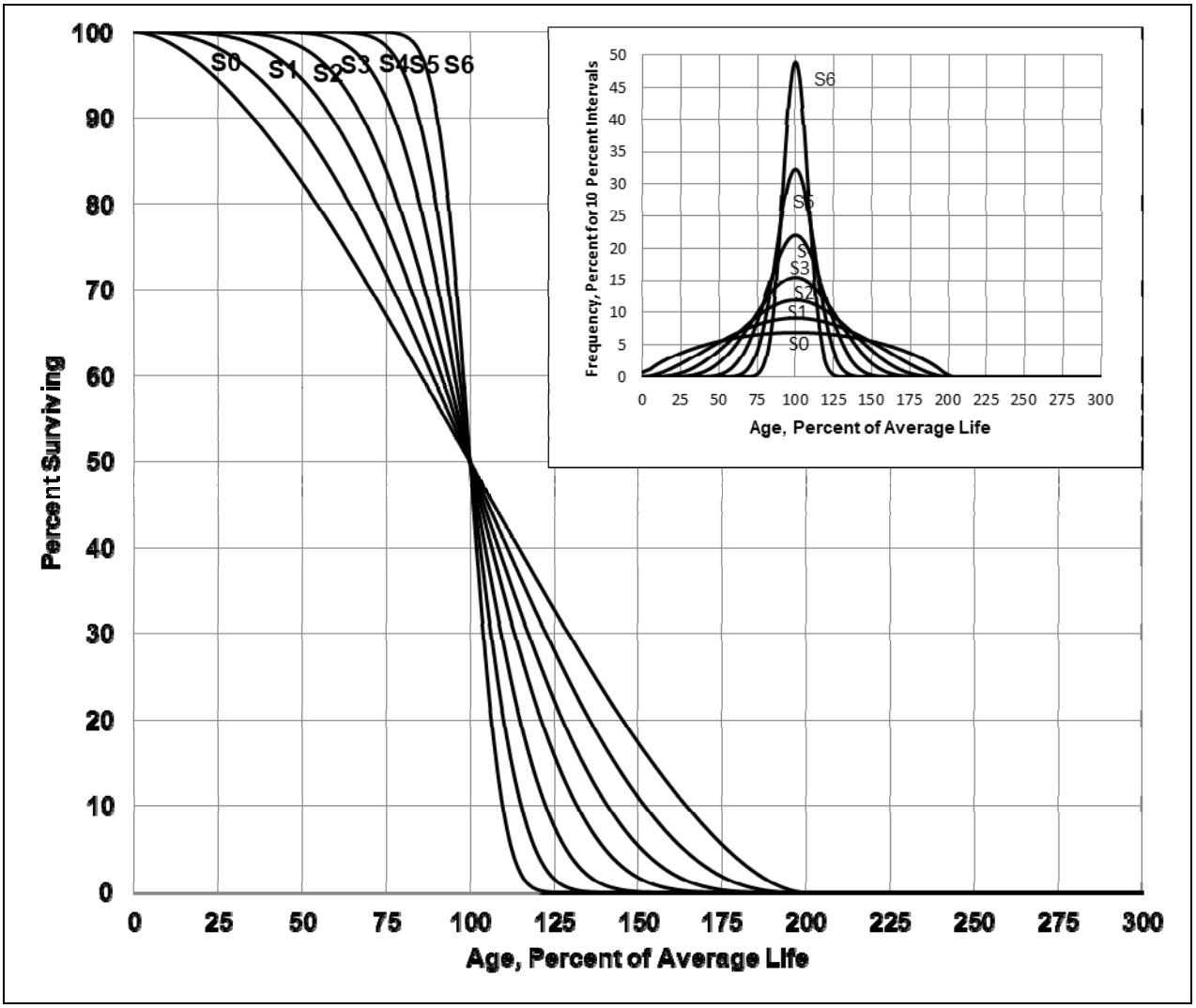
There are four families in the Iowa Curves that are distinguished by the relation of the age at the retirement mode (largest annual retirement frequency) and the average life. For distributions with the mode age greater than the average life, an "R" designation (i.e., Right modal) is used. The family of “R” moded curves is shown below.

R-TYPE IOWA SURVIVOR CURVES



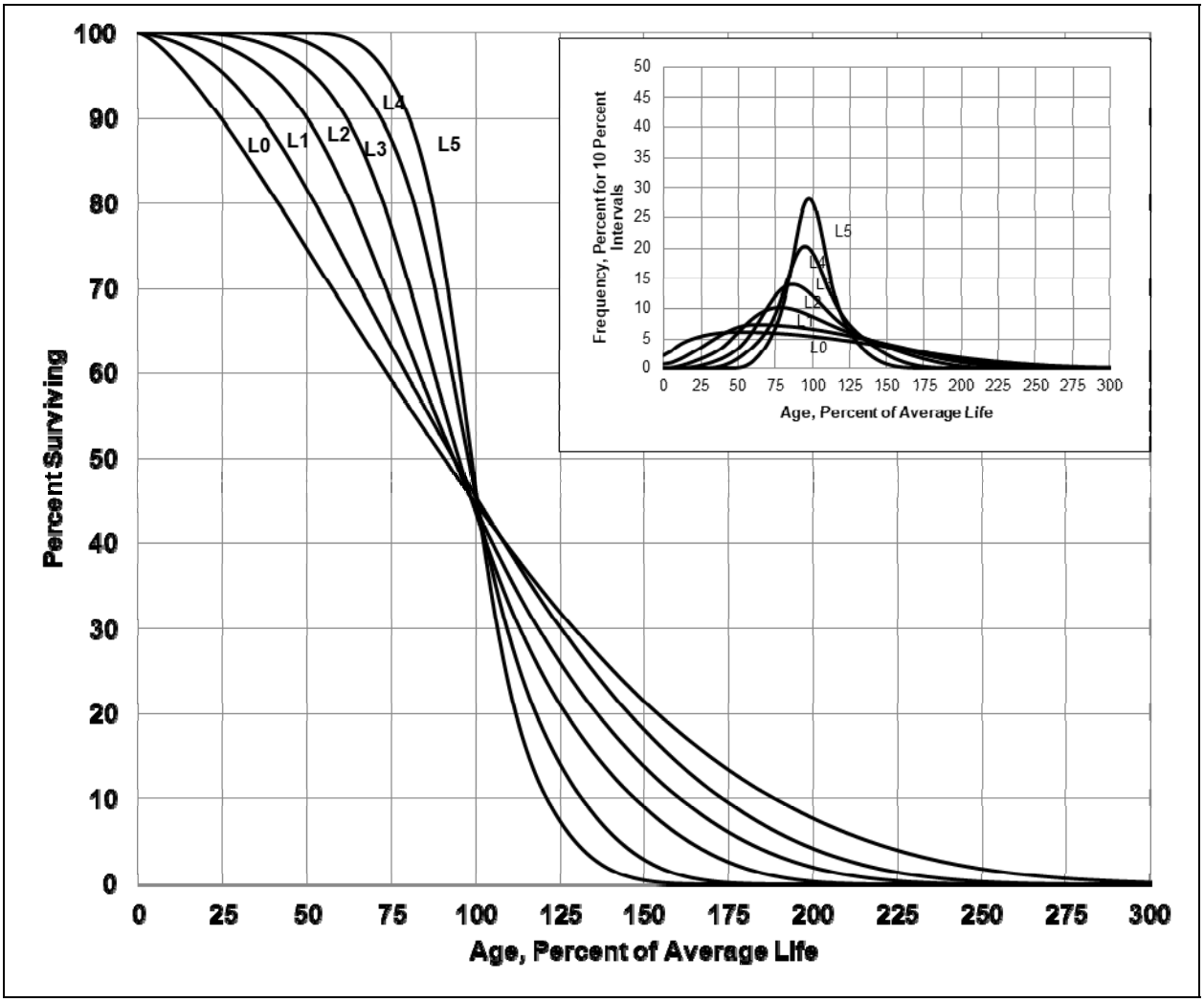
Similarly, an "S" designation (i.e., Symmetric modal) is used for the family whose mode age is symmetric about the average life. The higher the number of the curve, the greater the peak. A graph showing the S curves is shown below.

S-TYPE IOWA SURVIVOR CURVES



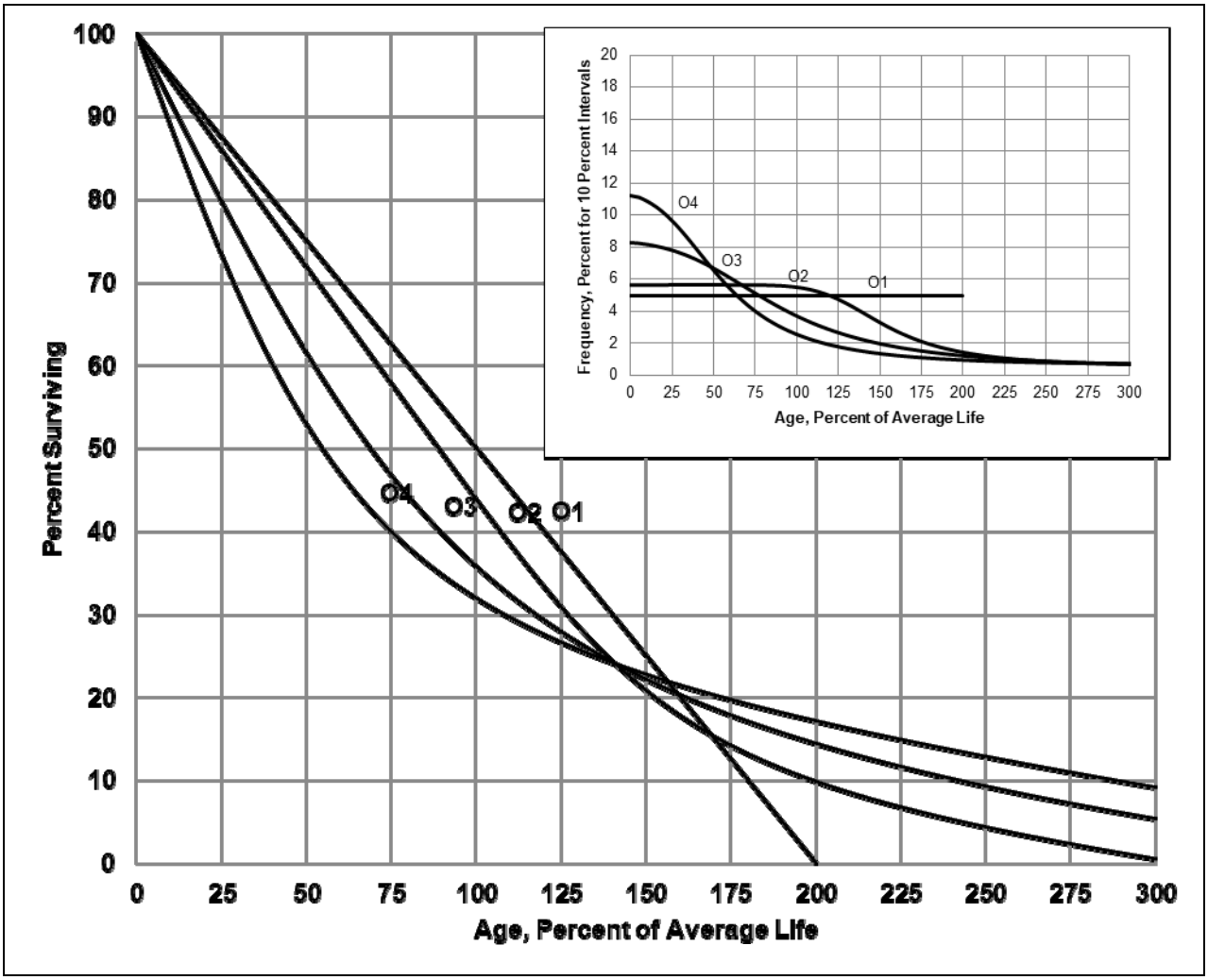
For distributions with the mode age less than the average life, a "L" designation (i.e., Left modal) is used. The family of “L” moded curves is shown below.

L-TYPE IOWA SURVIVOR CURVES



A special case of left modal dispersion is the "O" or origin modal curve family which was developed in the 1950s.

O-TYPE IOWA SURVIVOR CURVES



Given how long the O curves live, the O curves are seldom used in analyzing utility property in Alliance Consulting Group's experience. The O curves have been used for intellectual property.

Within each curve family, numerical designations are used to describe the relative magnitude of the retirement frequencies at the mode. A "6" indicates that the retirements are not greatly dispersed from the mode (i.e., high mode frequency), while a "1" indicates a large dispersion about the mode (i.e., low mode frequency). For example, a curve with an average life of 30 years and an "L3" dispersion is a moderately dispersed, left modal curve that can be designated as a 30 L3 Curve. An SQ, or square, survivor curve occurs where no dispersion is present (i.e., units of common age retire simultaneously).

Most property groups can be closely fitted to one Iowa Curve with a unique average service life. The blending of judgment concerning current conditions and future trends along with the matching of historical data permits the depreciation analyst to make an informed selection of an account's average life and retirement dispersion pattern.

Actuarial Analysis

Actuarial analysis (retirement rate method) was used in evaluating historical asset retirement experience where vintage data was available and sufficient retirement activity was present. In actuarial analysis, interval exposures (total property subject to retirement at the beginning of the age interval, regardless of vintage) and age interval retirements are calculated. The complement of the ratio of interval retirements to interval exposures establishes a survivor ratio. The survivor ratio is the fraction of property surviving to the end of the selected age interval, given that it has survived to the beginning of that age interval. Survivor ratios for all the available age intervals were chained by successive multiplications to establish a series of survivor factors, collectively known as an observed life table. The observed life table shows the experienced mortality characteristic of the account and may be compared to standard mortality curves such as the Iowa Curves. Where data was available, accounts were analyzed using this method. Placement bands were used to illustrate the composite history over a specific era, and experience

bands were used to focus on retirement history for all vintages during a set period. The results from these analyses for those accounts which had data sufficient to be analyzed using this method are shown in the Life Analysis section of this report.

Judgment

Alliance Consulting Group is an international consulting firm formed in 2004 by Dane Watson. In addition to the partner, Alliance also has four full-time Senior Consultants, Dr. Karen Ponder, Ms. Rhonda Watts, Ms. Rebecca Richards, and Mr. Rich Bennett, as well as other support staff. Alliance is dedicated to providing quality consulting and expert services to the utility industry. Our professionals have more than 175 years of combined experience around the utility industry, and we have been employed in the industry as utility employees and consultants. Alliance Consulting Group has performed nearly 400 depreciation studies for electric, gas, steam, water, wastewater, cable, and communications utilities across North America since its founding by Mr. Watson in 2004. These utilities encompass regulated, non-regulated, municipal, and federal agencies. The resumes of our personnel and a listing of our many engagements is provided in Appendix F. Given Alliance personnel's experience in accounting, fixed assets, engineering, and depreciation theory, we have an unparalleled expertise to incorporate in analyzing the Company's assets and recommending depreciation accrual rates.

Any depreciation study requires informed judgment by the analyst conducting the study. A knowledge of the property being studied, company policies and procedures, general trends in technology and industry practice, and a sound basis of understanding depreciation theory are needed to apply this informed judgment. Judgment was used in areas such as survivor curve modeling and selection, depreciation method selection, and actuarial analysis.

Judgment is not defined as being used in cases where there are specific, significant pieces of information that influence the choice of a life or curve. Those cases would simply be a reflection of specific facts into the analysis. Where there

are multiple factors, activities, actions, property characteristics, statistical inconsistencies, implications of applying certain curves, property mix in accounts or a multitude of other considerations that impact the analysis (potentially in various directions), judgment is used to take all of these factors and synthesize them into a general direction or understanding of the characteristics of the property. Individually, no one factor in these cases may have a substantial impact on the analysis, but overall, may shed light on the utilization and characteristics of assets. Judgment may also be defined as deduction, inference, wisdom, common sense, or the ability to make sensible decisions. There is no single correct result from statistical analysis; hence, there is no answer absent judgment. At the very least, for example, any analysis requires choosing which bands to place more emphasis.

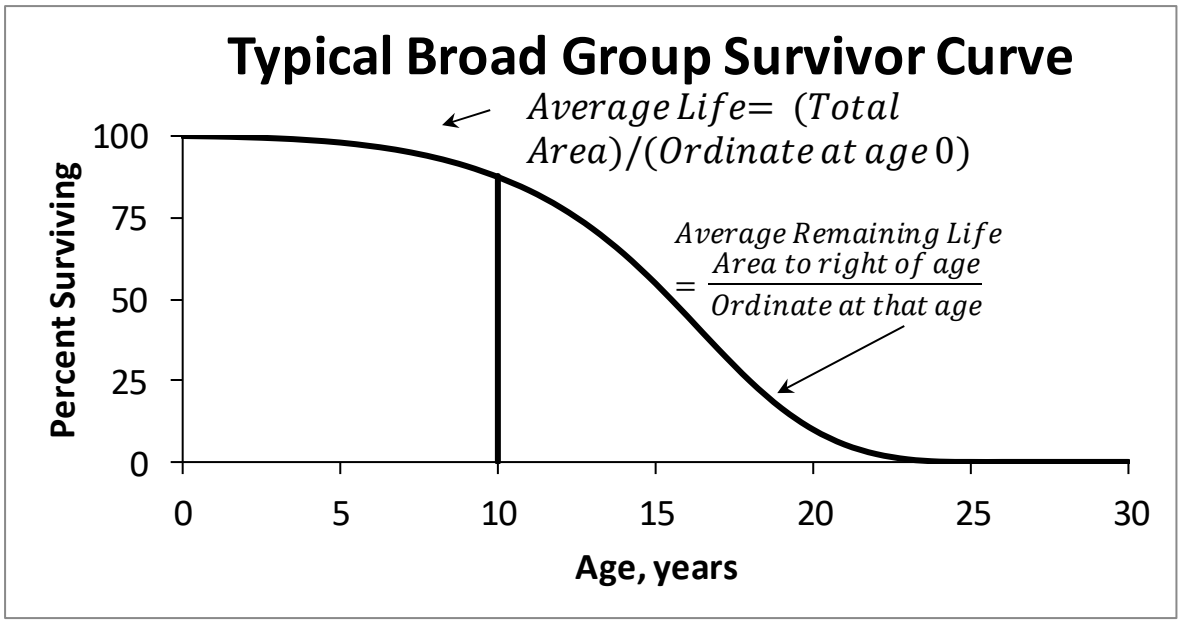
The establishment of appropriate average service lives and retirement dispersions for Hydro One's plant accounts requires judgment to incorporate the understanding of the operation of the system with the available accounting information analyzed using the Retirement Rate actuarial methods. The appropriateness of lives and curves depends not only on statistical analyses, but also on how well future retirement patterns will match past retirements.

Current applications and trends in use of the equipment also need to be factored into life and survivor curve choices in order for appropriate mortality characteristics to be chosen.

Average Life Group Depreciation

There are two depreciation "groupings" most commonly used in average life group depreciation: broad group and vintage group. Broad group ("BG") assumes that all units of plant in a plant account are considered to be one group. The BG produces stable results over many periods and, in Alliance Consulting Group's experience, is the most common depreciation system used across the industry. The BG system was used and approved in Hydro One's last JRAP application.

A typical broad group survivor curve is shown below.



This study proposes to continue using the average life group, broad group depreciation system to group the assets within each account. In Alliance's experience, this depreciation system is the most commonly used system across North America.

Theoretical Depreciation Reserve and Reserve Rebalancing

The book depreciation reserve was derived from Company records at the individual account level. This study used a reserve model that relied on a prospective concept relating to future retirement and accrual patterns for property, given current life and salvage estimates. This study recommends and uses reserve reallocation to rebalance reserves within each business unit and function. Reserve reallocation is when the book reserve is re-spread within a functional group based on the theoretical reserve within each function. In the process of analyzing the Company's depreciation reserve, Alliance Consulting Group observed that the depreciation reserve positions of the accounts were generally not in line with the life characteristics found in the analysis of the Company's assets. To allow the relative reserve positions of each account within a function to mirror the life characteristics of the underlying assets, we reallocated the depreciation reserves for all accounts within each function. The depreciation reserve represents the amounts that have been collected as a systemic allocation of the cost of an asset over its useful life, including any net salvage that may be required to remove that asset from service upon retirement. The reallocation process does not change the total reserve for each function; it simply reallocates the reserve between accounts in the function. Depreciation reserve allocation is a sound depreciation practice. The National Association of Regulatory Utility Commissioners endorsed the practice in its 1968 publication of *Public Utility Depreciation Practices*, explaining that reallocation of the depreciation reserve is appropriate "…where the change in the view concerning the life of property is so drastic as to indicate a serious difference between the theoretical and the book reserve."[2] Additionally, the 1996 edition of *Public Utility Depreciation Practices* states that "theoretical reserve studies also have been conducted for the purpose of allocating an existing reserve among operating units or accounts."[3]

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[2] *Public Utility Depreciation Practices*, Published by the National Association of Regulatory Utility Commissioners, 1968, page 48.

[3] *Public Utility Depreciation Practices*, Published by the National Association of Regulatory Utility

The theoretical reserve of a group is developed from the estimated remaining life, total life of the property group, and estimated net salvage. The theoretical reserve represents the portion of the group cost that would have been accrued if current forecasts were used throughout the life of the group for future depreciation accruals. The computation involves multiplying the vintage balances within the group by the theoretical reserve ratio for each vintage. The average life group method requires an estimate of dispersion and service life to establish how much of each vintage is expected to be retired in each year until all property within the group is retired. Estimated average service lives and dispersion determine the amount within each average life group. The straight-line remaining-life theoretical reserve ratio at any given age (RR) is calculated as:

$$RR = 1 - \frac{(Average\ Remaining\ Life)}{(Average\ Service\ Life)} * (1 - Net\ Salvage\ Ratio)$$

In the case of Hydro One, no net salvage is incorporated in depreciation accrual rates, consistent with other Canadian utilities. Reserve reallocation has been used in the Company's previous transmission and distribution depreciation studies.

Commissioners, 1996, page 188.

DETAILED DISCUSSION

Depreciation Study Process

This depreciation study encompassed four distinct phases. The first phase involved data collection and field interviews. The second phase was where the initial data analysis occurred. The third phase was where the information and analysis were evaluated. Once the first three stages were complete, the fourth phase began. This phase involved the calculation of deprecation rates and documentation of the corresponding recommendations.

During the Phase 1 data collection process, historical data was compiled from continuing property records and general ledger systems. Data was validated for accuracy by extracting and comparing to multiple financial system sources. Audit of this data was validated against historical data from prior periods, historical general ledger sources, and field personnel discussions. This data was reviewed extensively to put in the proper format for a depreciation study. Also, as part of the Phase 1 data collection process, numerous discussions were conducted with engineers and field operations personnel to obtain information that would assist in formulating life and salvage recommendations in this study. One of the most important elements of performing a proper depreciation study is to understand how the Company utilizes assets and the environment of those assets. Interviews with engineering and operations personnel are important ways to allow the analyst to obtain information that is beneficial when evaluating the output from the life and net salvage programs in relation to the company's actual asset utilization and environment. Information that was gleaned in these discussions is found in the Detailed Discussion of this study in the life analysis sections.

Phase 2 is where the actuarial analysis is performed. Phases 2 and 3 overlap to a significant degree. The detailed property records information is used in Phase 2 to develop observed life tables for life analysis. These tables are visually compared to industry standard tables to determine historical life characteristics. It is possible that the analyst would cycle back to this phase based on the evaluation

process performed in Phase 3. Net salvage analysis consists of compiling historical salvage and removal data by functional group to determine values and trends in gross salvage and removal cost. No net salvage is incorporated in Hydro One's depreciation accrual rates, consistent with its accounting practices, with other Canadian utilities, and with its previous studies. Net salvage was not included in the Company's prior Transmission, Distribution and Common depreciation studies. This information was then carried forward into phase 3 for the evaluation process.

Phase 3 is the evaluation process which synthesizes analysis, interviews, and operational characteristics into a final selection of asset lives and mortality curve parameters. The historical analysis from Phase 2 is further enhanced by the incorporation of recent or future changes in the characteristics or operations of assets that were revealed in Phase 1. Phases 2 and 3 allow the depreciation analyst to validate the asset characteristics as seen in the accounting transactions with actual Company operational experience.

Finally, Phase 4 involved the calculation of accrual rates, making recommendations and documenting the conclusions in a final report. The calculation of accrual rates is found in Appendix A. Recommendations for the various accounts are contained within the Detailed Discussion of this report. The depreciation study flow diagram shown as Figure 1[4] documents the steps used in conducting this study. Depreciation Systems[5], pages 285 - 292, documents the same basic processes in performing a depreciation study which are: statistical analysis, evaluation of statistical analysis, discussions with management and operational personnel, forecast assumptions, and documented recommendations.

[4] Public Utility Finance & Accounting, A Reader.
[5] Depreciation Systems, by Drs. W. C. Fitch and F.K. Wolf, Iowa State University Press, 1994, pages 285 - 292.

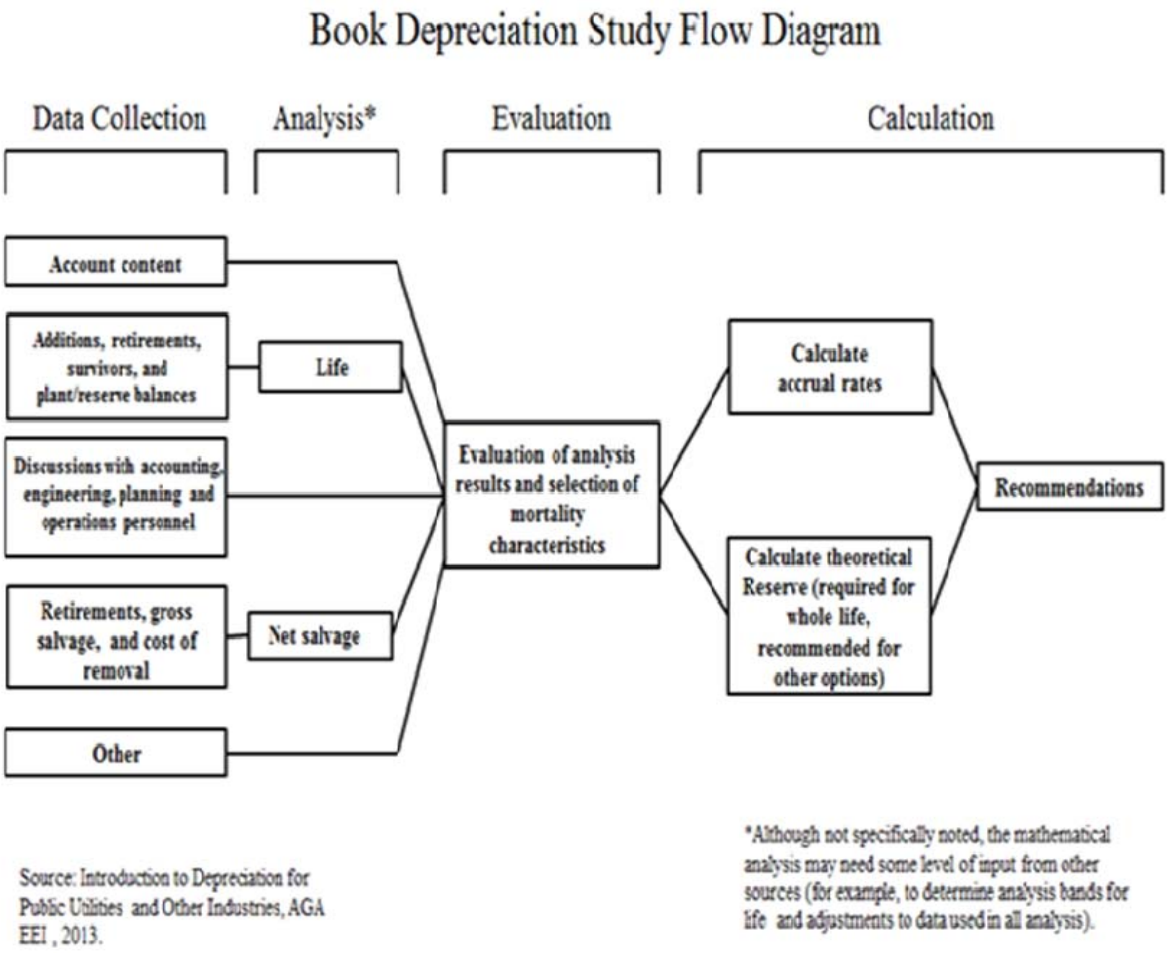


Figure 1

HYDRO ONE DEPRECIATION STUDY PROCESS

Depreciation Rate Calculation Process

The proposed rates are based on plant and accumulated depreciation reserve balances at December 31, 2024 and will be applied to test year data developed in the Joint Application. Annual depreciation expense amounts for all accounts were calculated by the straight-line method, broad (average) life group procedure, remaining-life technique. These calculations are shown in Appendix A. The results of calculations of the theoretical depreciation reserve values and the corresponding remaining life calculations are shown in Appendix D. Book depreciation reserves were based on Company individual accounts and the theoretical reserve computation was used to rebalance depreciation reserves and compute a composite remaining life for each account.

LIFE ANALYSIS

The retirement rate actuarial analysis method was applied to all accounts for Hydro One. For each account, an actuarial retirement rate analysis was made with placement and experience bands of varying widths. The historical observed life table was plotted and compared with various Iowa Curves to obtain the most appropriate match. A representative curve for each account is shown in the Life Analysis Section of this report.

Company history is compiled to develop observed survivor curves which are matched against the Iowa Curve families discussed above. An observed survivor curve that does not reach 0% surviving is a stub curve. Because the average life associated with a survivor curve is represented by the area under the complete survivor curve, the observed survivor curve must be smoothed and extended to 0% surviving. If more historical data is available to analyze, the observed survivor curve (stub curve) will be longer (i.e., getting closer to 0 percent surviving). Hence the more history available in the data, the more predictable and reliable the resulting Company observed survivor curve will be for selecting a complete survivor curve. It is desirable to have the stub curve drop below 50% surviving. The earliest

experience year available where retirement history for each account was available was 2000, due to the 1999 demerger from Ontario Hydro and various system conversions that occurred over time. Many of the Company's assets have existing lives longer than 50 years, and the observed life tables may not reach the desired 50% surviving.

For each account on the overall band (i.e., placement from earliest vintage year, which varied for each account, through 2024), approved survivor curves from the prior study, modified by subsequent orders if applicable, were used as a starting point. Then, using the same average life, various dispersion curves were plotted. Frequently, visual matching would confirm one specific dispersion pattern (e.g., L, S, or R) as an obviously better match than others. The matching process relies on expert judgment to determine which portion of the curve to match. The next step would be to determine the most appropriate life using that dispersion pattern. Then, after looking at the overall experience band, different experience bands were plotted and analyzed. Next, placement bands of varying width were plotted with each experience band discussed above. Repeated matching usually pointed to a focus on one dispersion family and small range of service lives. The goal of visual matching was to minimize the differential between the observed life table and Iowa Curve in the top and mid-range of the plots. These results are used in conjunction with all other factors that may influence asset lives.

Since Hydro One had aged data only going back to 1999, the short experience available for these long-lived accounts does not allow the observed life table to extend to a level that would allow the analyst to fully see the historical life-cycles for the assets being studied. To help better understand the historical characteristic of the assets being studied, interviews with Company subject matter experts ("SMEs") provided valuable information to estimate life characteristics. Company SMEs also provided estimated component lives for various assets in each plant account. The component life analysis for each business unit is found in Appendix E. The data in this study includes all retirement activity that Hydro One has experienced between

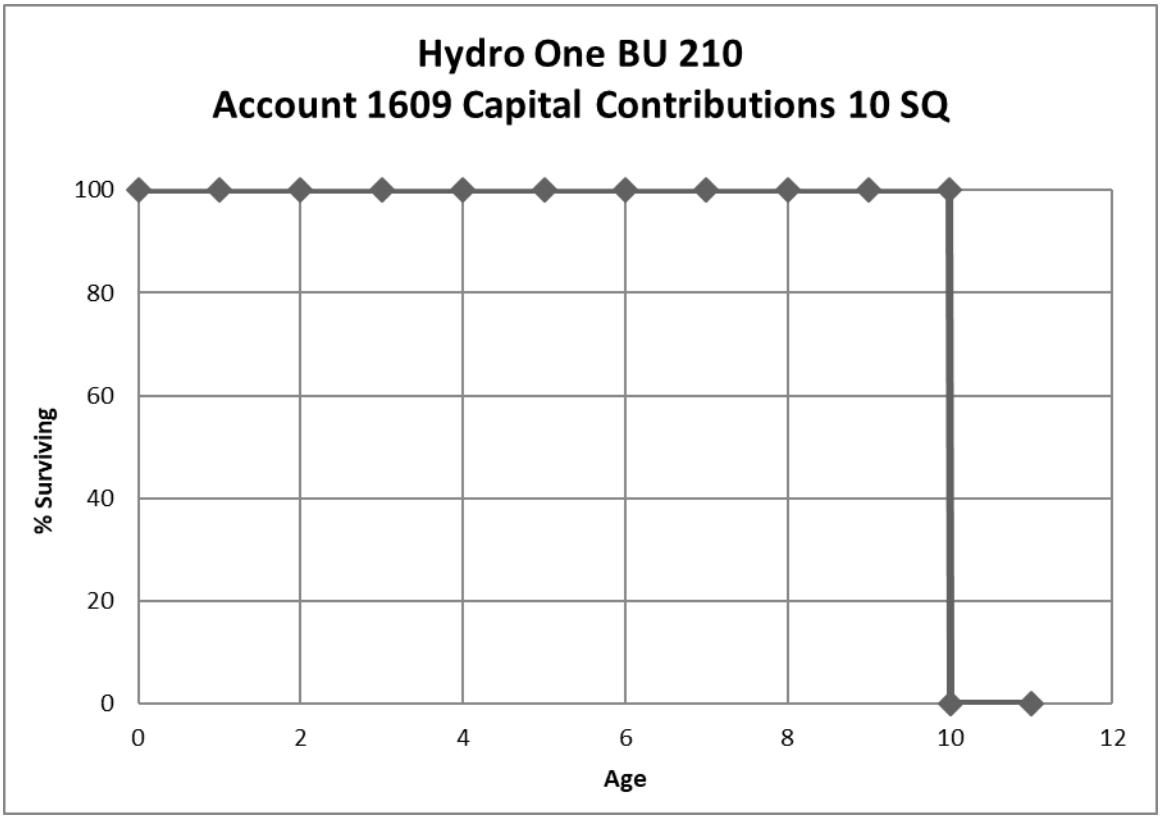
2000-2024. By including all past events, this study expressly contemplates the range of natural disasters that Hydro One has experienced in the past, along with the associated impact on early retirement of damaged or destroyed assets. Over time, natural events such as storms, flooding, or wildfires can occur and may cause the early retirement of assets. Such events have occurred during the period from 2000-2024 in Company history and will recur in the future given climate change and unknown future events.

BU 210 TRANSMISSION OPERATIONS
INTANGIBLE FUNCTIONAL GROUP

Accounts in the intangible function are amortized. When those assets are fully accrued, amortization ceases. Any new assets added to an account are amortized using the life assigned to the account.

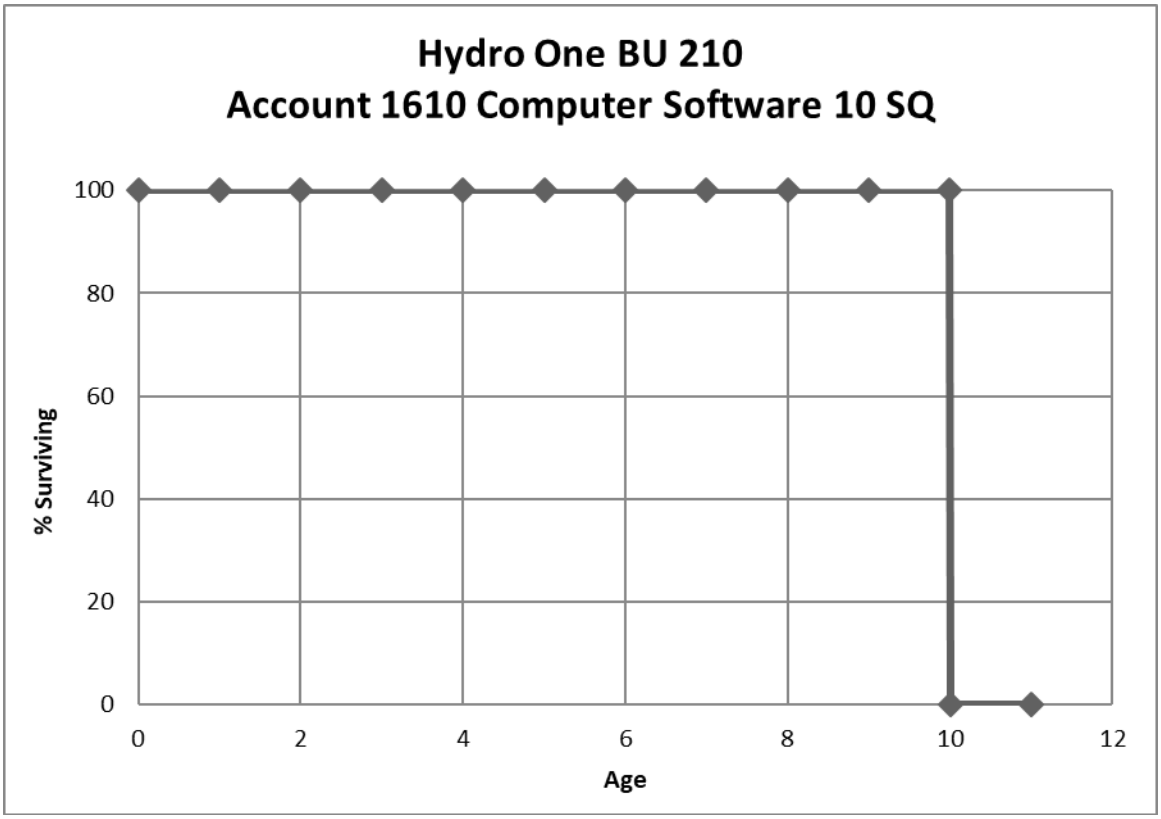
Account 1609 Capital Contributions (10 SQ)

This account consists of capital contributions for the Transmission Operations group. The plant balance in this account at December 31, 2024 is $15.1 million. Currently the amortization life of this account is 10 years. After reviewing plant lives with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.



Account 1610 Computer Software (10 SQ)

This account consists of computer software for the Transmission Operations group. Such assets include general system software and various fiber optic equipment. The plant balance in this account at December 31, 2024 is $98.4 million. Currently the amortization life of this account is 10 years. After reviewing plant lives with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.

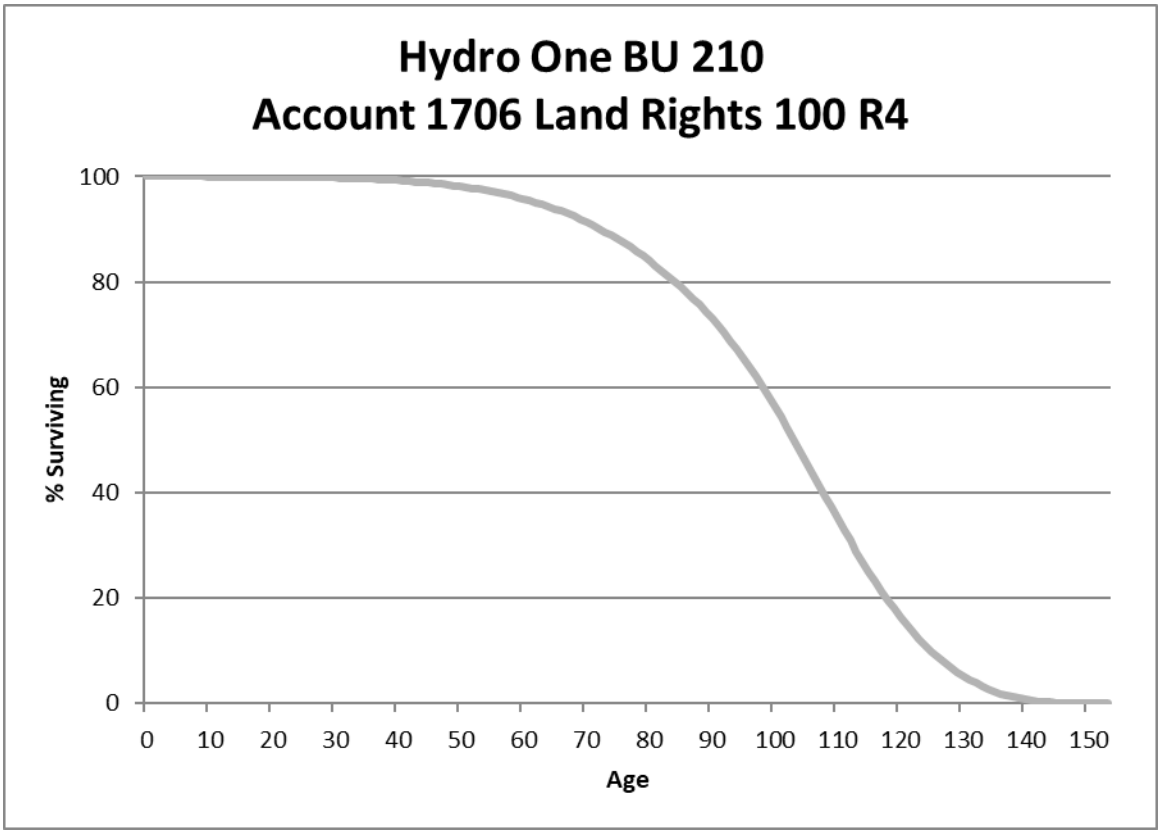


TRANSMISSION FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

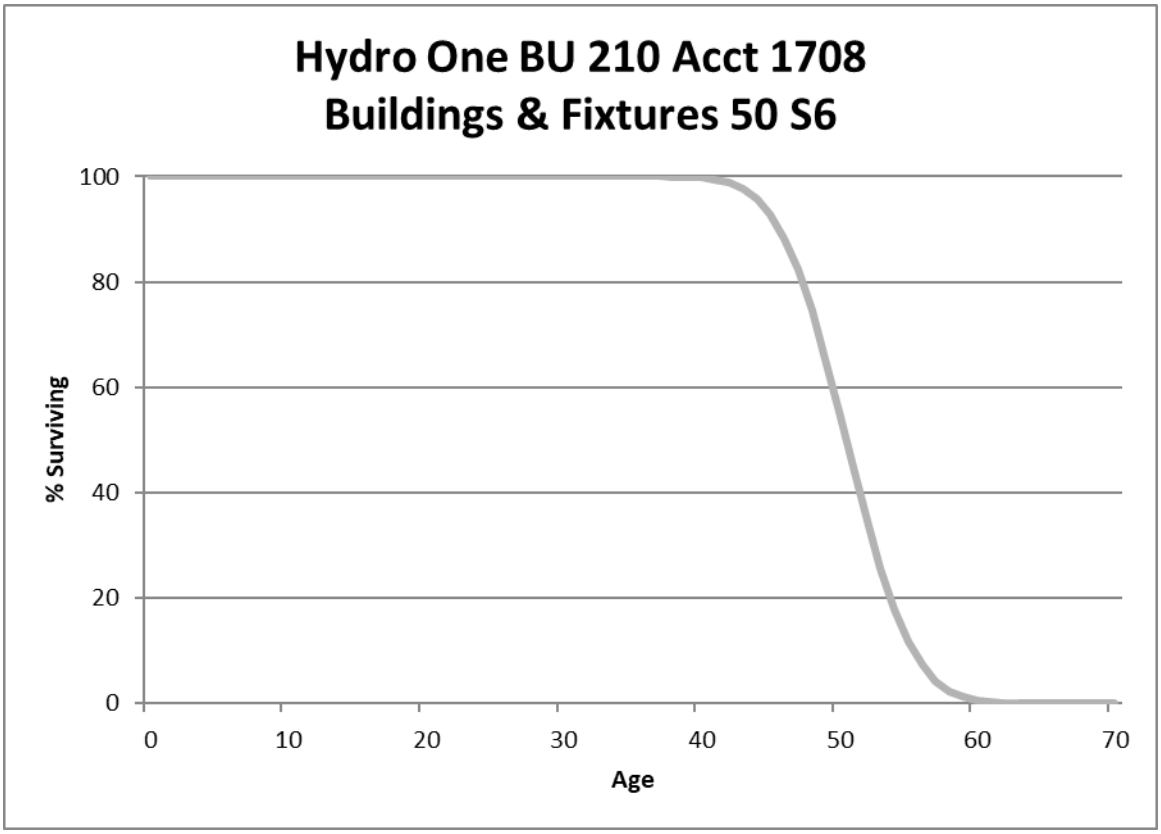
Account 1706 Land Rights (100 R4)

This account consists of land rights associated with Transmission Operations. Such assets include easements and site improvements. The plant balance in this account at December 31, 2024 is $263.6 million. Currently, the life of this account is 100 years with an R4 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the conclusion was that the existing 100-year life with an R4 dispersion is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 100-year life with an R4 dispersion.


Hydro One BU 210
Account 1706 Land Rights 100 R4
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
Age

Account 1708 Buildings and Fixtures (50 S6)

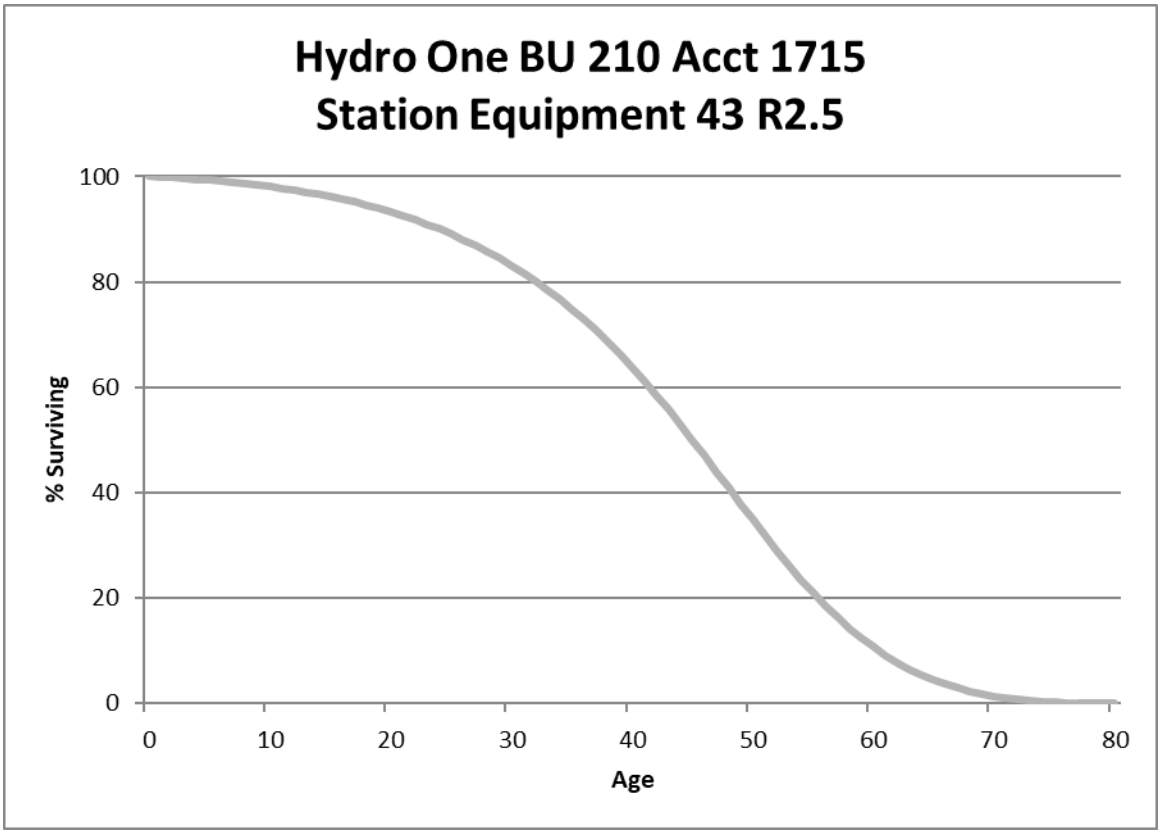
This account consists of various buildings and fixtures associated with Transmission Operations. Such assets include transmission station buildings, building components, cranes and hoists in buildings, underground cable in buildings, and other station structures. The plant balance in this account at December 31, 2024 is $841.5 million. Currently, the life of this account is 50 years with an S6 dispersion. Discussions with Company SMEs reveal that buildings in this account are a mixture of two different types: prefabricated and brick and mortar. Prefabricated structures are estimated to have a 40-year life from an operational perspective. Brick and mortar buildings will have a longer life. Larger substations use brick and mortar materials. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 50-year life with an S6 dispersion.


Hydro One BU 210 Acct 1708
Buildings & Fixtures 50 S6
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
Age

Account 1715 Station Equipment (43 R2.5)

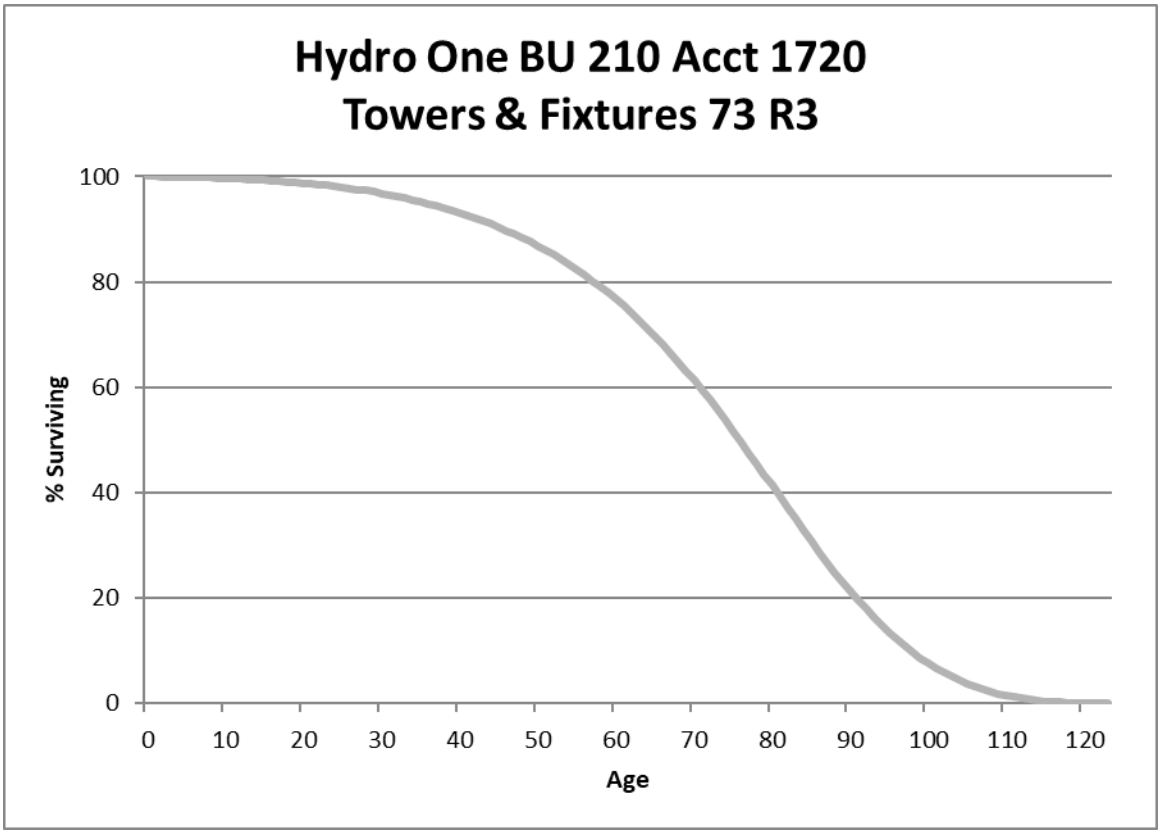
This account consists of a variety of station equipment within Transmission Operations. Such assets include landscaping, fencing, foundations, capacitors, switchboards, control equipment, switching equipment, transformers, and regulators. The plant balance in this account at December 31, 2024 is $13.2 billion. Currently the approved life of this account is 48 years with an R2.5 dispersion. Company SMEs note that there are a wide variety of assets in this account that are impacted by differing forces and timing of retirement. Significant components are experiencing changes: breakers are changing to SF6, relays are moving from analog to digital, and newer (second generation) IEDs have a longer life span. Newer equipment allows more ability to monitor load and aids in compliance and testing. Increasing levels of automation are being used on systems. Hydro One has standardized design and materials for transformers, and power transformers are now exhibiting a 45 to 55-year life. Company SMEs report that the Company does not run assets to failure, and that the Company uses program maintenance, defect reports, and condition assessment to prevent failures. Various component life projections are shown in Appendix E-1. Company SMEs do not recommend extending the life of this account. Some components in this account are showing a shorter life, such as voltage breakers, which are moving to SF6 technology as the Company moves away from oil breakers. The breaker change out is not an official program, and replacements are based on condition. Transformers are seeing more load and more wear and tear, and the component life is reduced from the last case.

Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination of a shorter life for this account is appropriate. For these reasons, a 43-year life with an R2.5 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210 Acct 1715
Station Equipment 43 R2.5
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
Age

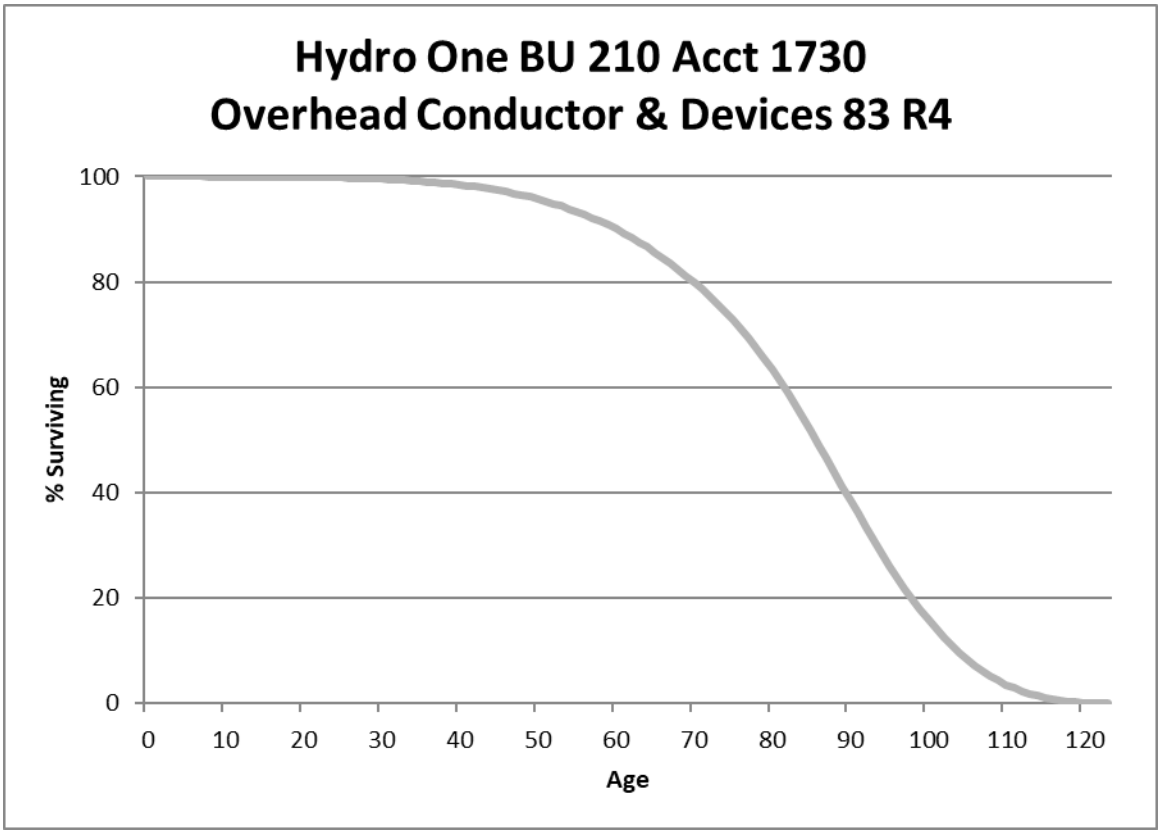
Account 1720 Towers and Fixtures (73 R3)

This account consists of towers and fixtures associated with Transmission Operations. Such assets include towers, steel poles, composite poles, crossarms, and anchors. The plant balance in this account at December 31, 2024 is $3.4 billion. Currently the life of this account is 75 years with an R3 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs provided operational life expectations for major components within this account in Appendix E-1. Steel towers are estimated to have an operational life similar to steel poles. Steel towers are primarily lattice designs. Other assets such as crossarms, guy wires, and anchors have a shorter life. After seeking input from Company personnel and incorporating professional judgment, the determination was that a slight reduction from the existing year life is appropriate for this account. For the reasons listed above, a 73-year life with an R3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210 Acct 1720
Towers & Fixtures 73 R3
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
120
Age

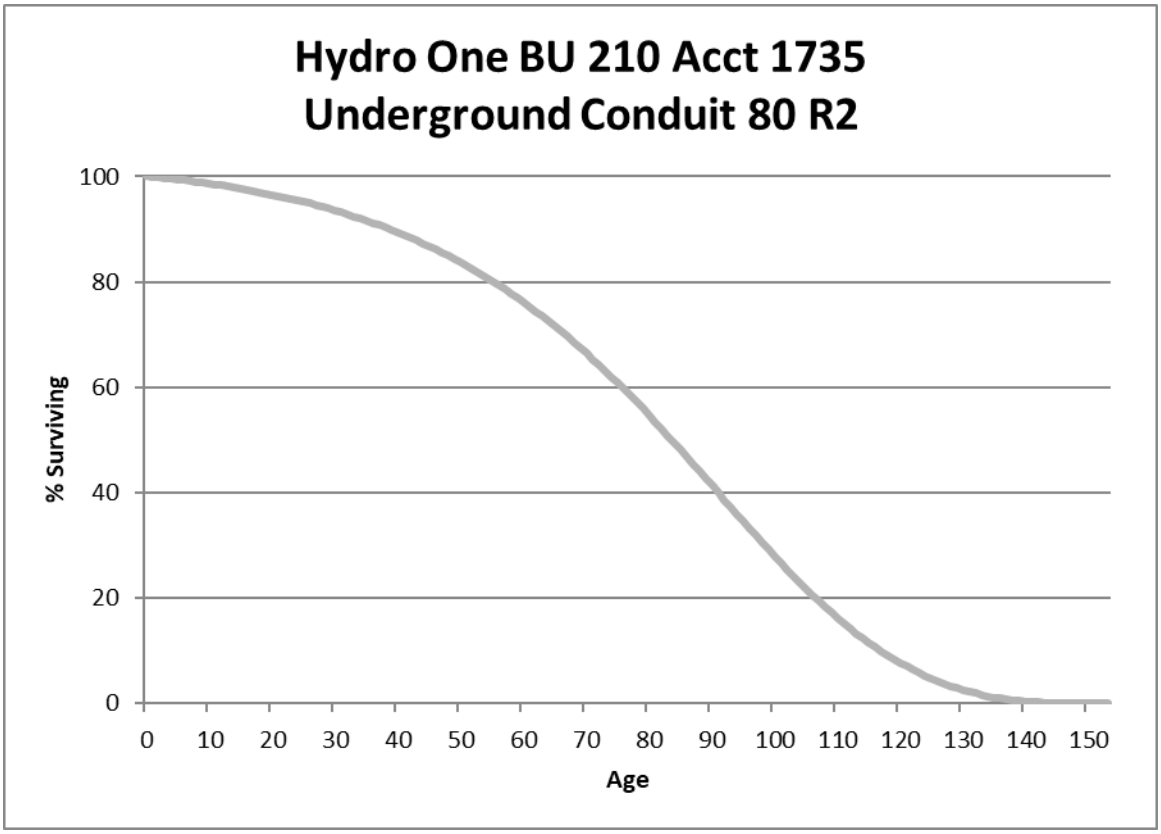
Account 1730 Overhead Conductors and Devices (83 R4)

This account consists of various overhead and conductors associated with Transmission Operations. Such assets include insulators, ground wire, switches and devices, and overhead conductor and devices. The plant balance in this account at December 31, 2024 is $2.6 billion. Currently the life of this account is 70 years with an R4 dispersion. Limited retirement activity exists to analyze the life of the account. Recent studies from EPRI looked at the physical life for these assets and have updated a condition assessment of these assets. Reconductoring and rebuilding lines can affect the life of conductor. Capacity change is captured in physical condition and demographics of the areas. The Company has focused on line losses as well. Switches are about half analog and half digital. Insulators are made of polymer and glass. Polymer insulators have experienced cracking at the base. Component lives have lengthened for some categories in this account, and the composite life shown in Appendix E is 83 years. After seeking input from Company personnel, who stated movement to 80 years seems operationally reasonable, and incorporating professional judgment, the determination was that the existing life should be extended for this account. For the reasons listed above, an 83-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210 Acct 1730
Overhead Conductor & Devices 83 R4
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
120
Age

Account 1735 Underground Conduit (80 R2)

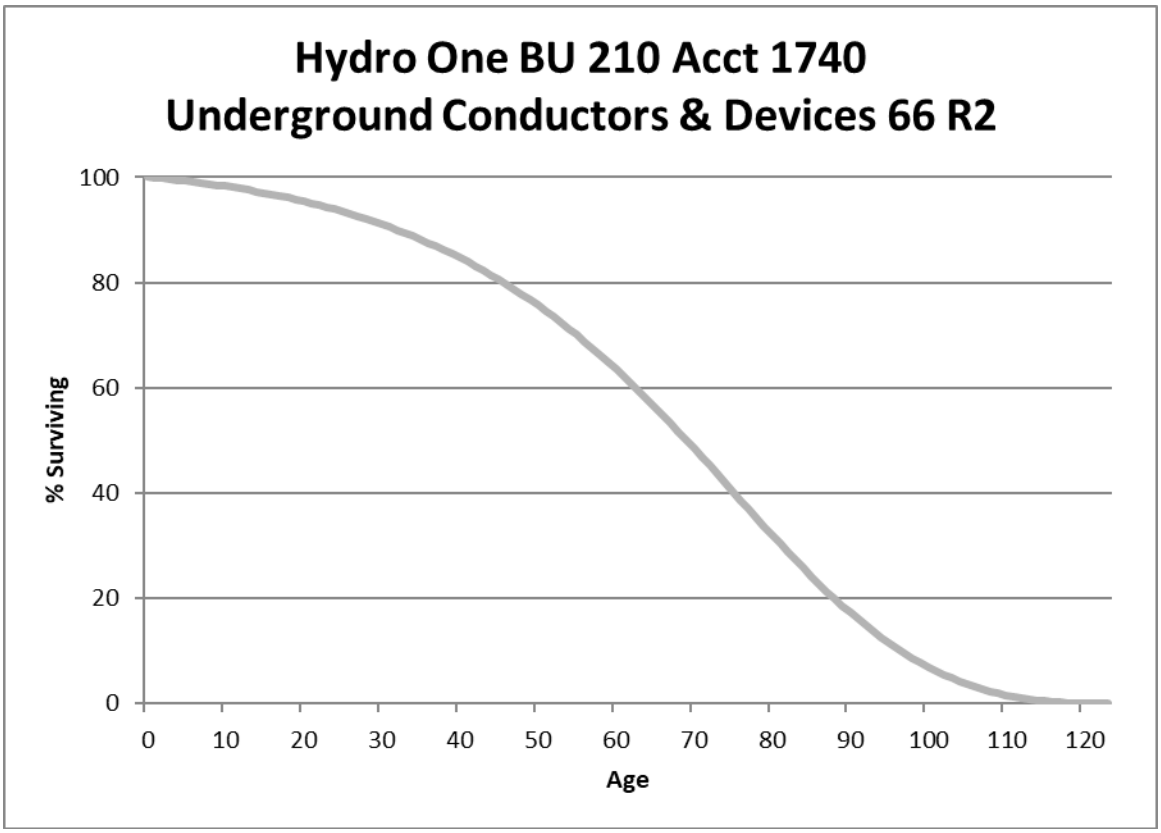
This account consists of various underground conduit used to deliver electric service for Transmission Operations. Such assets include transmission station buildings, cranes and hoists in buildings, underground cable in buildings, and other station structures. The plant balance in this account at December 31, 2024 is $312.7 million. Currently the life of this account is 60 years with an R2 dispersion. Limited retirement activity exists to analyze the life of the account. Company personnel believe that there are some operational reasons that the conduit should have a slightly longer life in some cases than the cable within the conduit. The component lives in Appendix E-1 show a component life of 80 years, which is longer than the life currently in place. After seeking input from Company personnel and incorporating professional judgment, the determination was that the life should be extended for this account. For the reasons listed above, an 80-year life with an R2 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



Account 1740 Underground Conductors and Devices (66 R2)

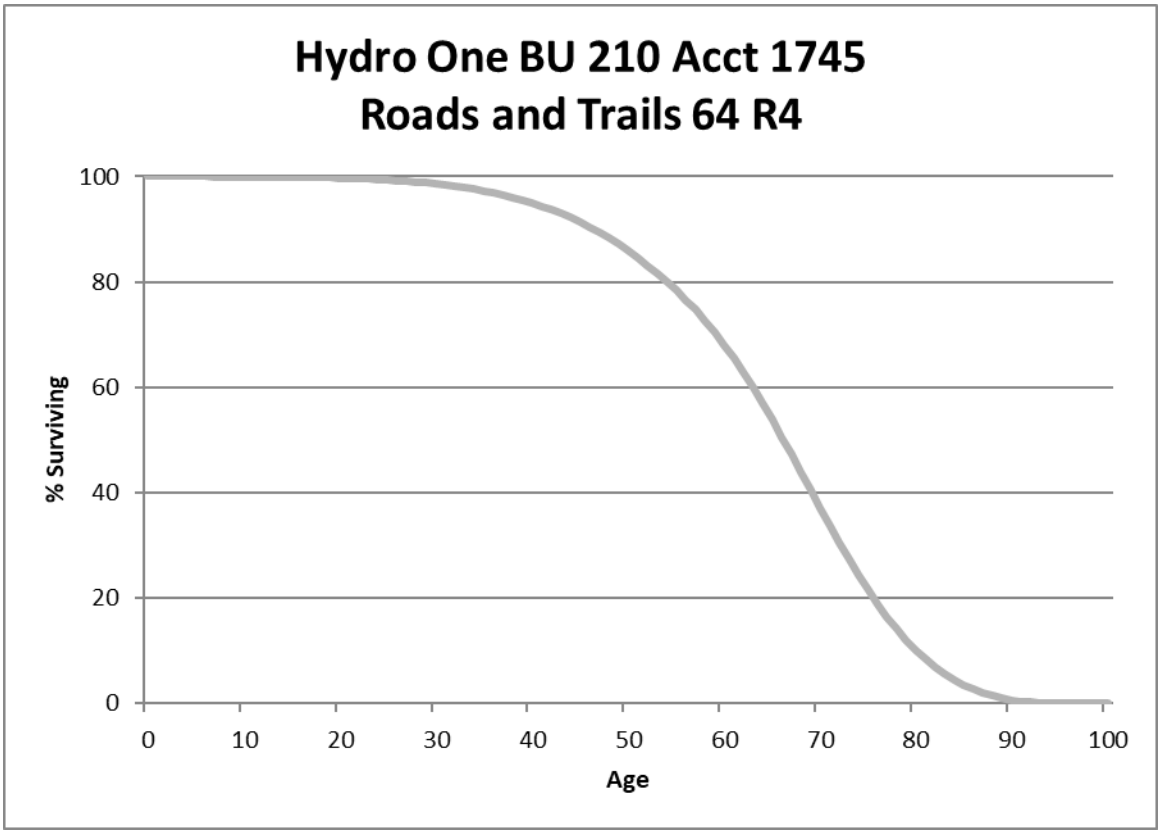
This account consists of various underground conductors and devices used to deliver electric service associated with Transmission Operations. The plant balance in this account at December 31, 2024 is $187.1 million. Currently the life of this account is 55 years with an R2 dispersion. The oldest assets in this account were installed from years 2000-2024, and limited retirement activity exists to analyze the life of the account. Since the observed life table only goes to 99 percent surviving, there is insufficient data to perform visual matching. Company SMEs report that assets in Account 1735 – Conduit would have a longer life from an operational standpoint than assets in the 1740 – Underground Conductors and Devices account. The component lives in Appendix E-1 show a component life of 66 years, which is longer than the life currently in place. After seeking input from Company personnel and incorporating professional judgment, the determination was

that the existing 55-year life too short for this account. For the reasons listed above, a 66-year life with an R2 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



Account 1745 Road and Trails (64 R4)

This account consists of various roads and trails associated with Transmission Operations. Such assets include roads, clearing, and surfaces areas used for transmission facilities. The plant balance in this account at December 31, 2024 is $542.4 million. Currently the life of this account is 60 years with an R4 dispersion. Limited retirement activity exists to analyze the life of the account. The component lives in Appendix E-1 show a component life of 64 years, which is longer than the life currently in place. Company personnel believe that this account should have a longer life. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing life should be extended for this account. For the reasons listed above, a 64-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.

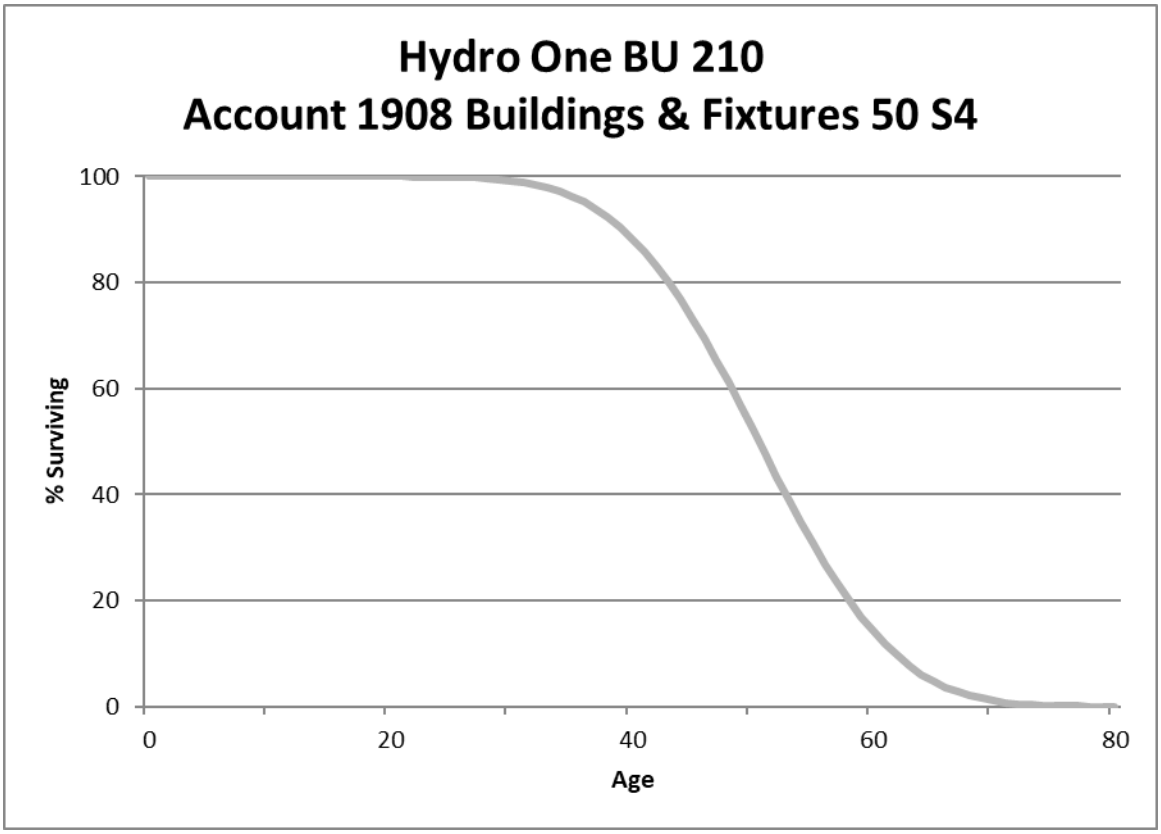

Hydro One BU 210 Acct 1745
Roads and Trails 64 R4
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
Age

GENERAL DEPRECIATED FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

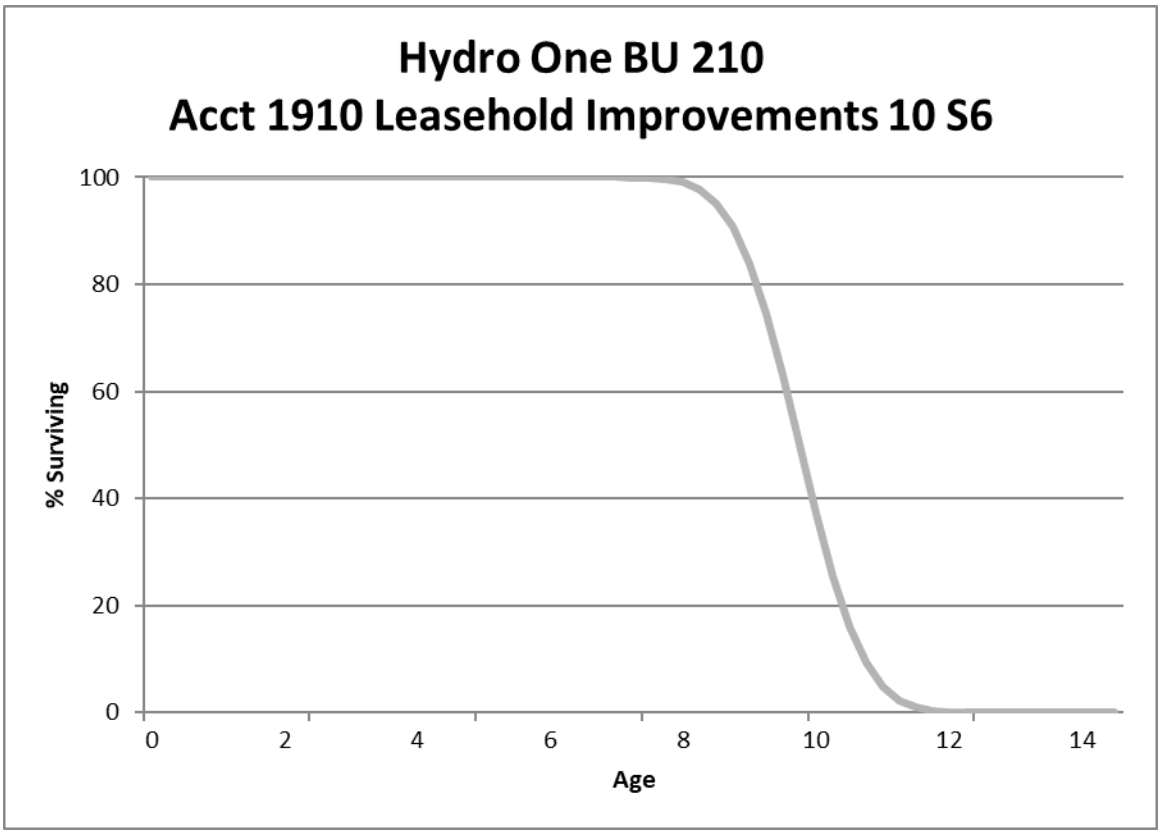
Account 1908 Buildings and Fixtures (50 S4)

This account consists of various buildings and fixtures associated with Transmission Operations. Such assets include buildings, landscaping, fencing, roads and surfaces, and other structures. The plant balance in this account at December 31, 2024 is $208.8 million. Currently the life of this account is 50 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. Based upon the component lives in Appendix E-1, the overall composite for this account is 49 years. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50 year should be retained. A 50-year life with an S4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 210
Account 1908 Buildings & Fixtures 50 S4
100
80
60
40
20
0
% Surviving
0
20
40
60
80
Age

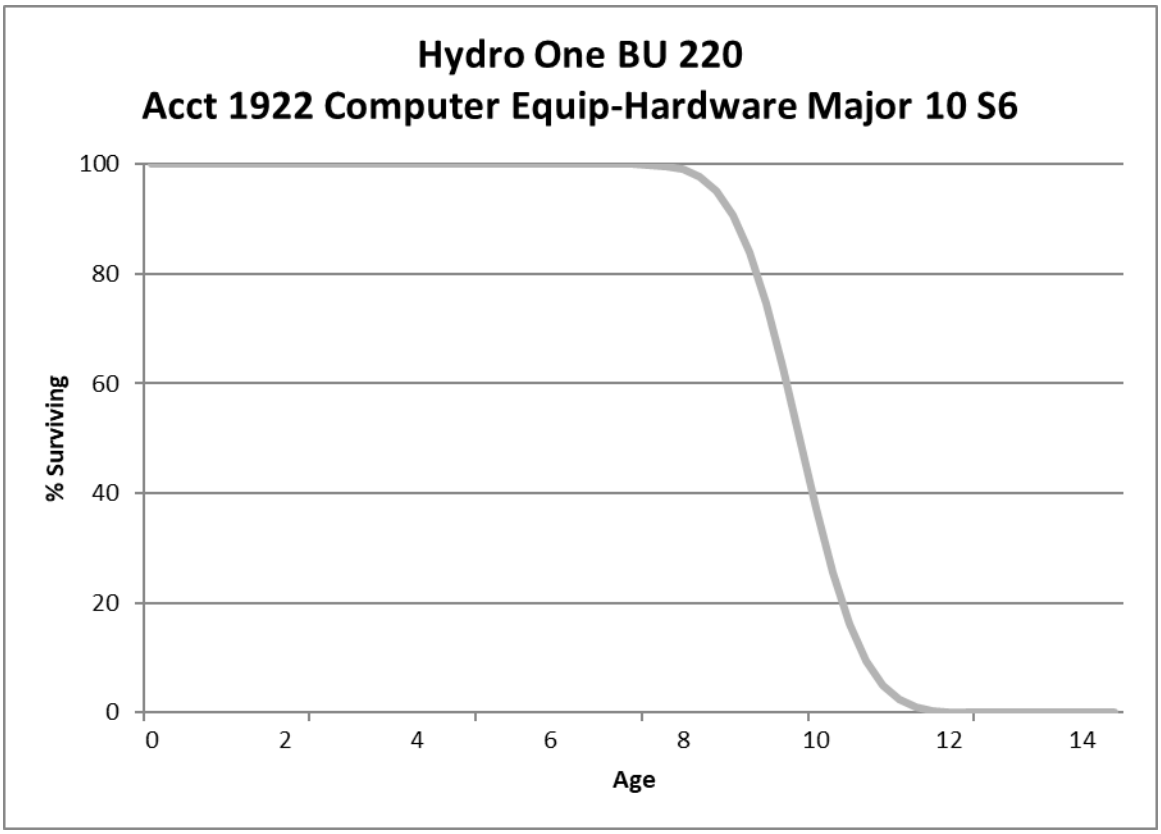
Account 1910 Leasehold Improvements (10 S6)

This account consists of various leasehold improvements made to leased buildings associated with Transmission Operations. The plant balance in this account at December 31, 2024 is $0.1 million. Currently the life of this account is 10 years with an S6 dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



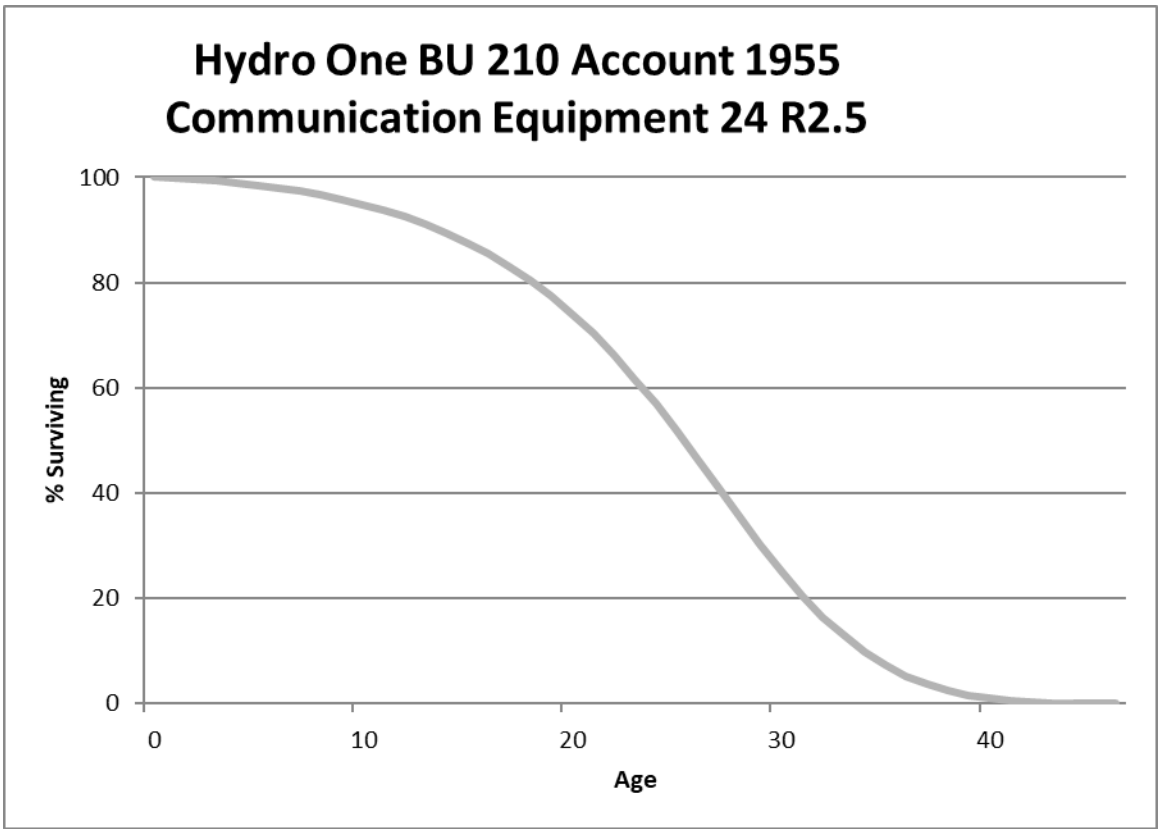
Account 1922 Computer Equipment - Hardware Major (10 S6)

This account consists of various major computer hardware equipment associated with Transmission Operations. Such assets include local area network cable, fiber optic equipment, and electrical devices. The plant balance in this account at December 31, 2024 is $43.9 million. Currently the life of this account is 10 years with an S6 dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life should be retained for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



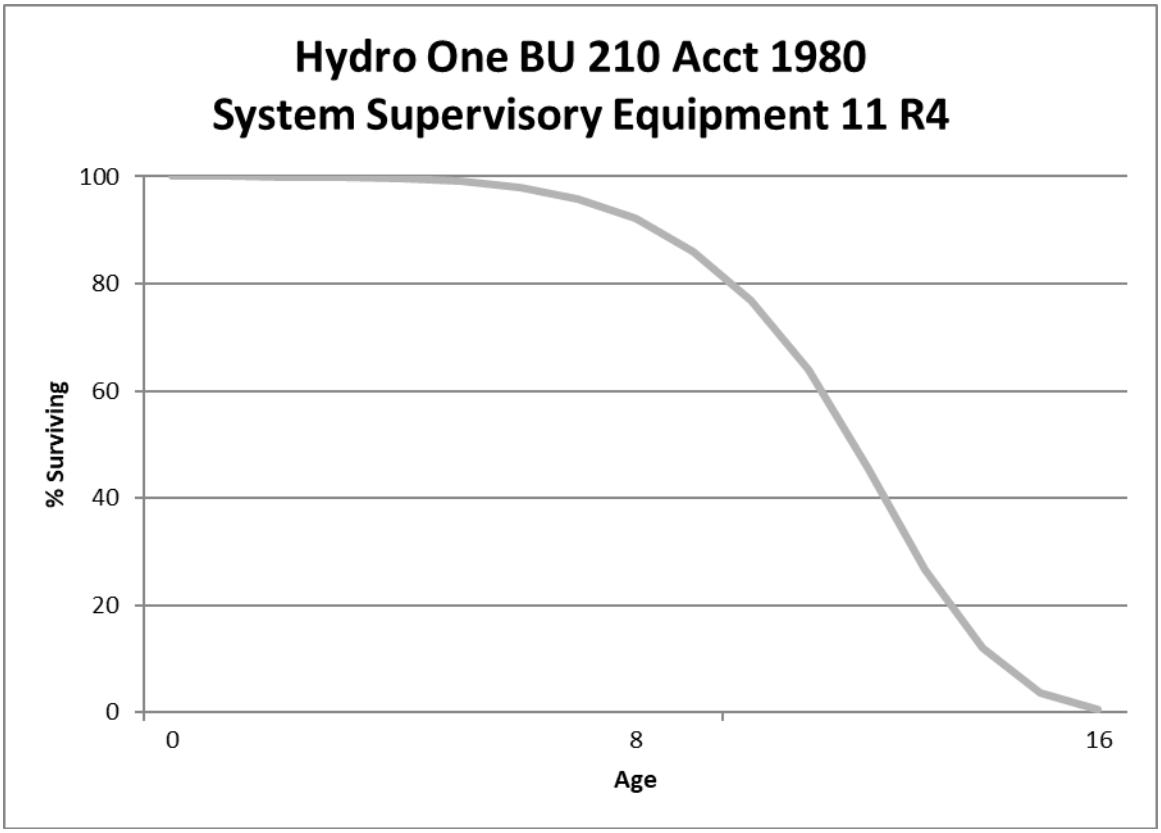
Account 1955 Communication Equipment (24 R2.5)

This account consists of various communication equipment associated with Transmission Operations. Such assets include telecom equipment, switching equipment, radios, optical wire, fiber optic cable, and power supply equipment. The plant balance in this account at December 31, 2024 is $664.8 million. Currently, the life of this account is 20 years with an R2.5 dispersion. Limited retirement activity exists to analyze the life of the account. Component lives in Appendix E-1 show a 24-year composite life. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 20-year should be extended slightly for this account. For the reasons listed above, a 24-year life with an R2.5 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



Account 1980 System Supervisory Equipment (11 R4)

This account consists of system supervisory equipment associated with Transmission Operations. Such assets include power line equipment, software and hardware, and terminals. The plant balance in this account at December 31, 2024 is $454.3 million. Currently, the life of this account is 10 years with an R4 dispersion. After seeking input from Company personnel and incorporating professional judgment, the determination was that the life for this account should be extended slightly. Component lives in Appendix E-1 show an 11-year composite life. For the reasons listed above, an 11-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.

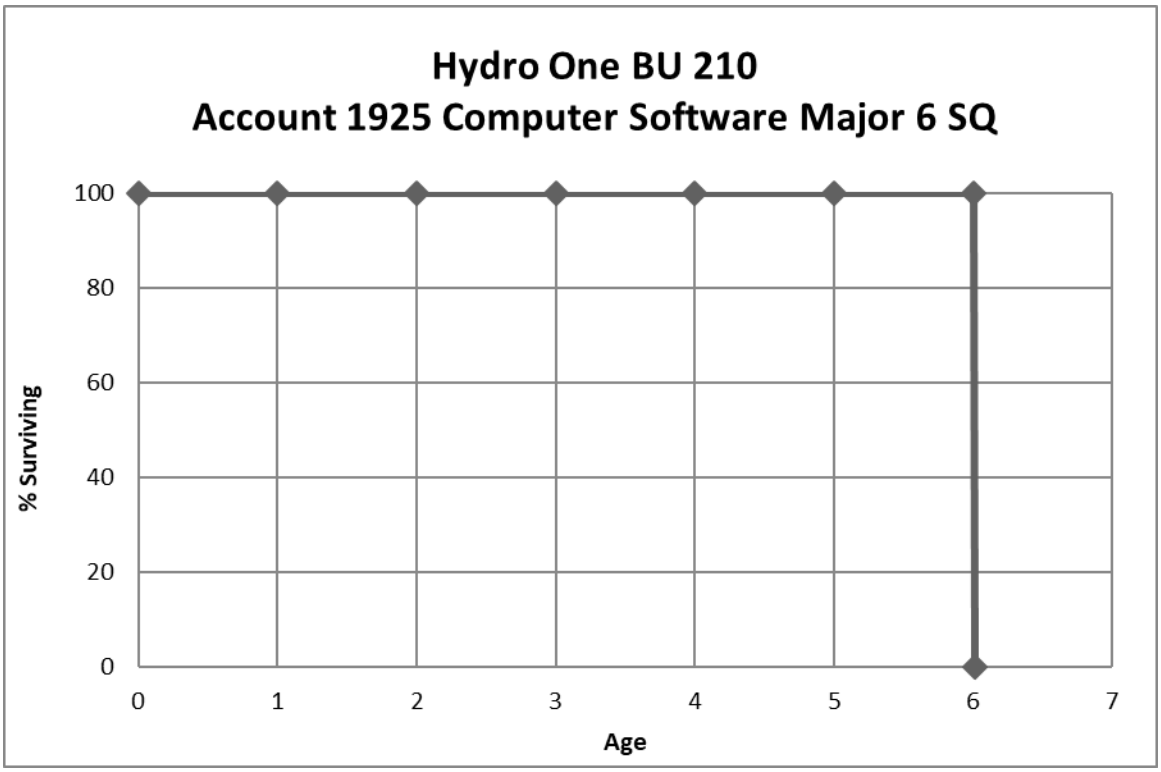


GENERAL AMORTIZED FUNCTIONAL GROUP

Accounts in the general amortized function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the life assigned to the account.

Account 1925 Computer Software (6 SQ)

This account consists of computer software for the Transmission Operations group. Such assets include general system software and various fiber optic equipment. The plant balance in this account at December 31, 2024 is $8.6 million. Currently the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 6-year life with an SQ dispersion.



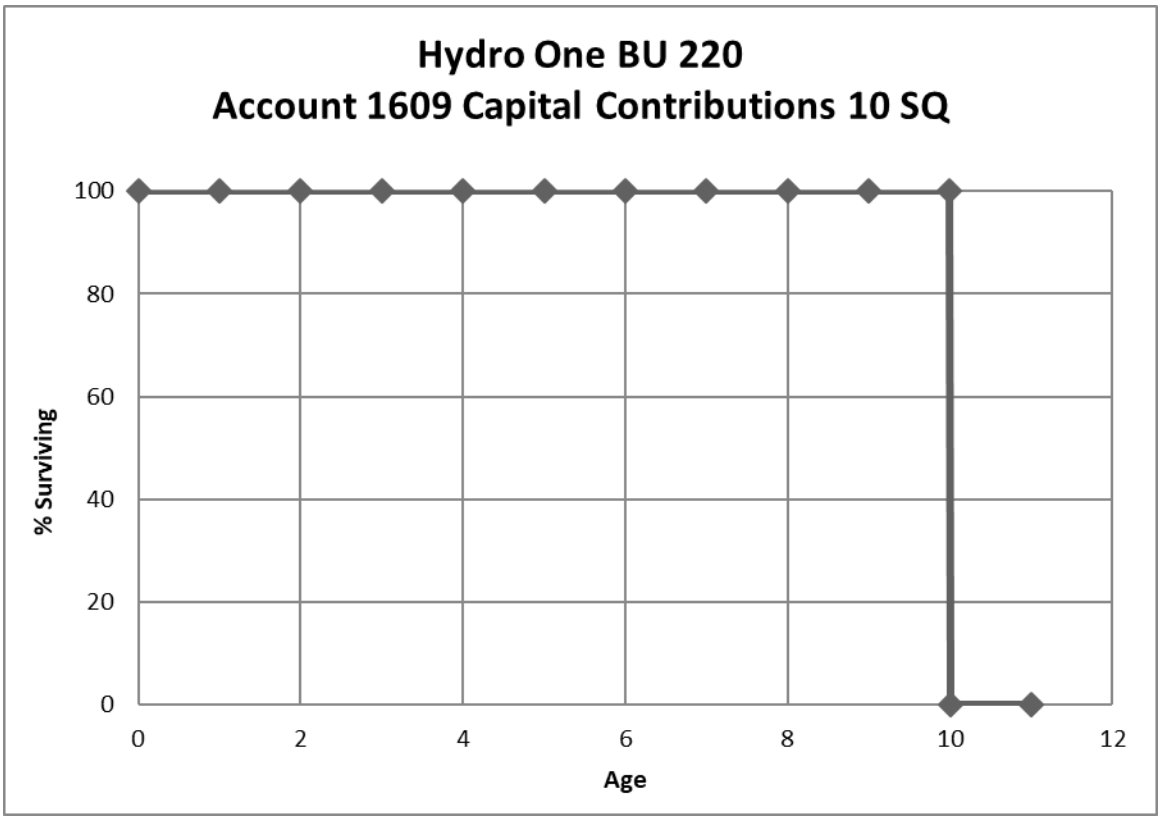
BU 220 DISTRIBUTION OPERATIONS

INTANGIBLE FUNCTIONAL GROUP

Accounts in the intangible function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the life assigned to the account.

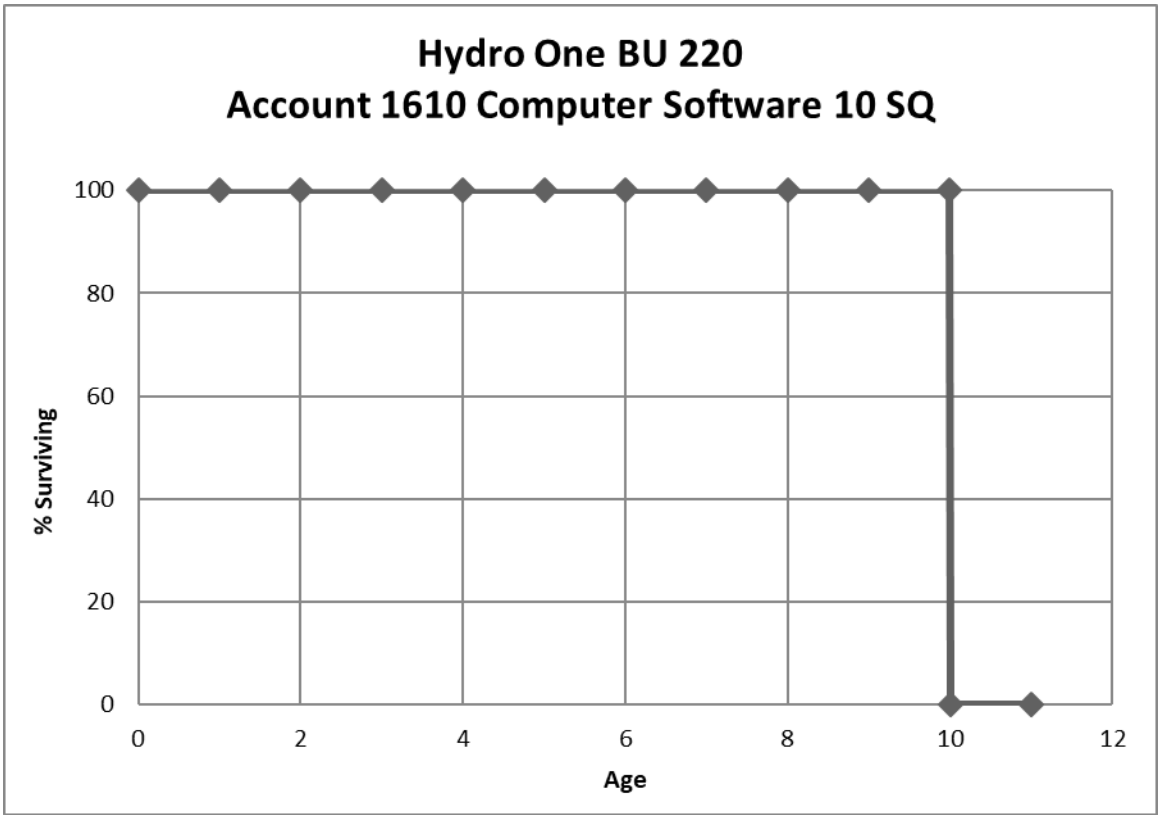
Account 1609 Capital Contributions (10 SQ)

This account consists of capital contributions for the Distribution Operations group. The plant balance in this account at December 31, 2024 is $75.5 million. Currently the amortization life of this account is 10 years. After reviewing the life with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.


Hydro One BU 220
Account 1609 Capital Contributions 10 SQ
% Surviving
100
80
60
40
20
0
0
2
4
6
8
10
12
Age

Account 1610 Computer Software (10 SQ)

This account consists of computer software for the Distribution Operations group. Such assets include general system software. The plant balance in this account at December 31, 2024 is $271.2 million. Currently the amortization life of this account is 10 years. After reviewing plant lives with Company personnel, the determination was that the existing 10-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 10-year life with an SQ dispersion.

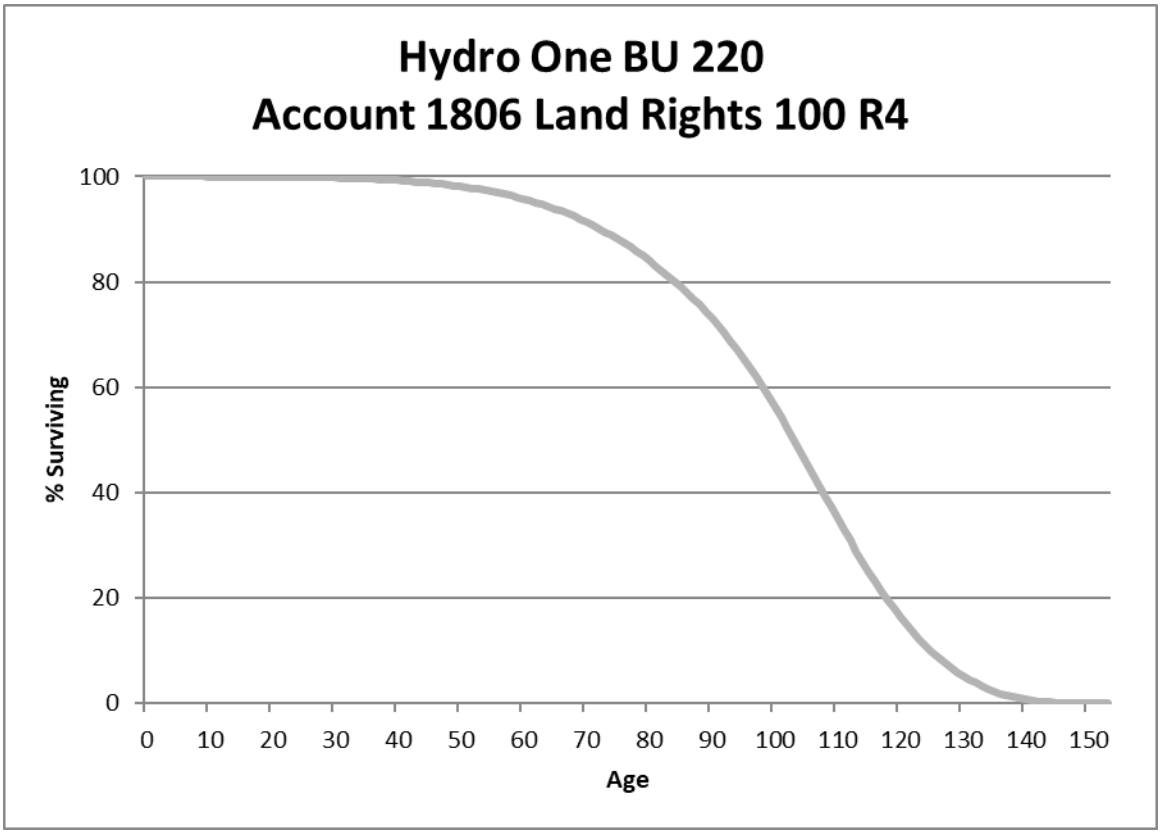


DISTRIBUTION FUNCTIONAL GROUP

Assets in the depreciated groups accrue depreciation until the asset is retired or transferred. When an asset is fully accrued, the asset and its accumulated depreciation are transferred to a non-depreciable account, so no further accrual occurs.

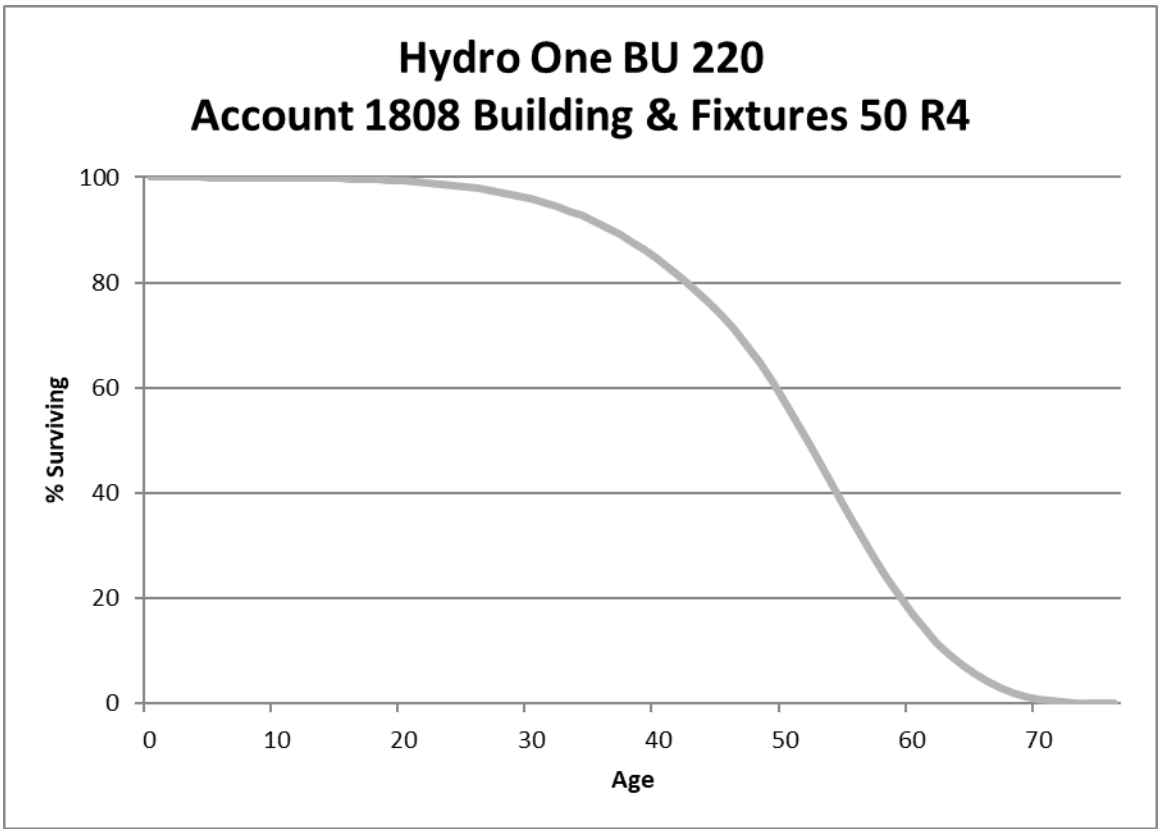
Account 1806 Land Rights (100 R4)

This account consists of land rights associated with Distribution Operations. Such assets include easements and site improvements. The plant balance in this account at December 31, 2024 is $295.4 million. Currently the life of this account is 100 years with an R4 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 100-year life is still appropriate for this account. In Alliance Consulting Group's experience, retirement characteristics of the property in this account model the R family, where more assets live longer than the average service life of the group. For the reasons listed above, a 100-year life with an R4 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1806 Land Rights 100 R4
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
120
130
140
150
Age

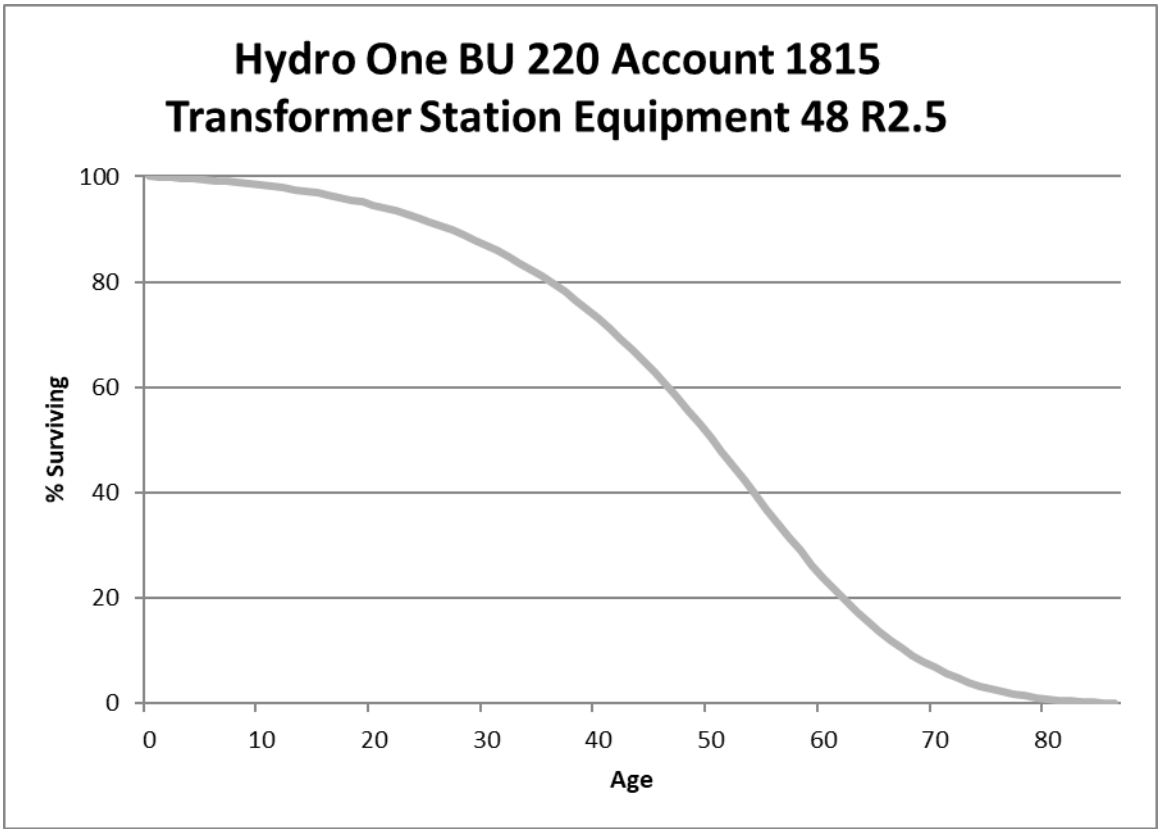
Account 1808 Buildings and Fixtures (50 R4)

This account consists of various buildings and fixtures associated with Distribution Operations. Such assets include distribution station buildings, landscaping, and other station structures. The plant balance in this account at December 31, 2024 is $28.6 million. Currently the life of this account is 50 years with an R4 dispersion. Limited retirement activity exists to analyze the life of the account. A summary of component lives for the account is shown in Appendix E. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50-year life is still appropriate for this account. For the reasons listed above, a 50-year life with an R4 dispersion is retained for this account. A representative graph for the life of the account is shown in the curve below.



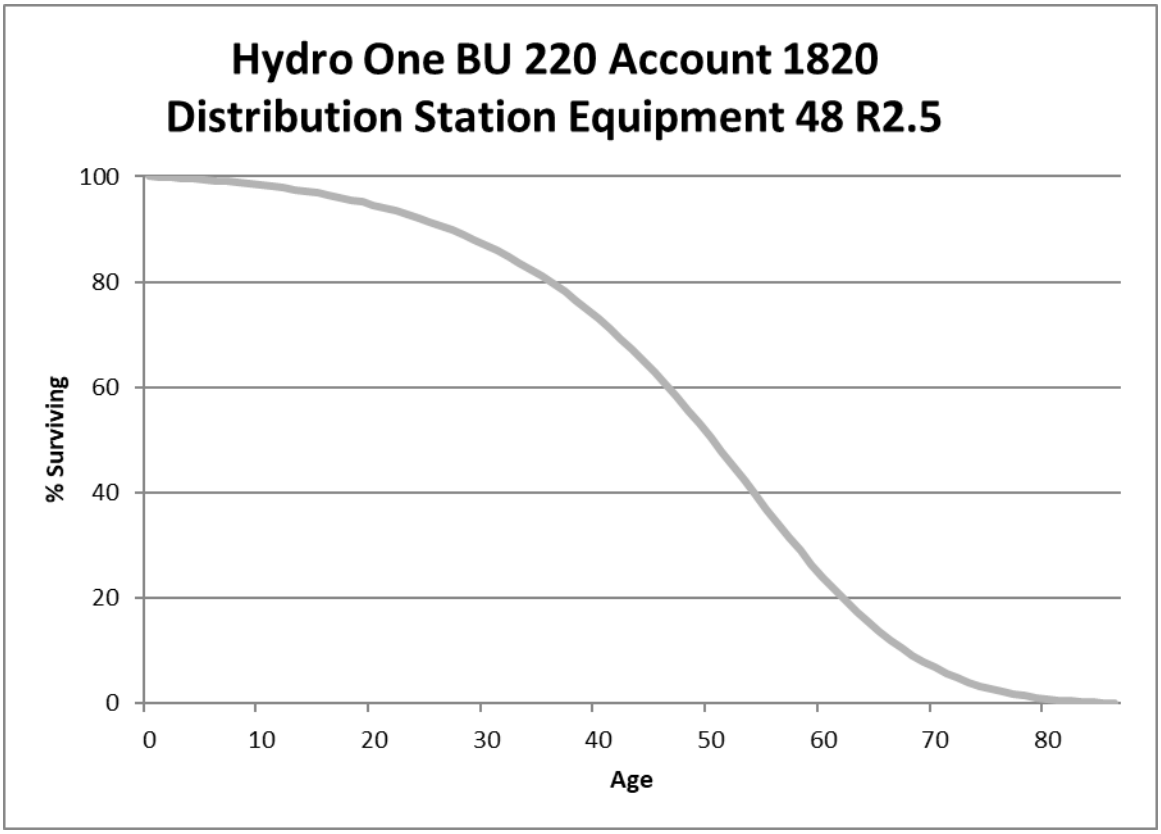
Account 1815 Transformer Station Equipment > 50 kV (48 R2.5)

This account consists of high side substation equipment associated with Distribution Operations. Such assets include site improvements, switchgear, foundations, fences, gates, grounding systems, capacitors, and transformers. The plant balance in this account at December 31, 2024 is $254.0 million. Currently the life of this account is 48 years with an R2.5 dispersion. Limited retirement activity exists to analyze the life of the account. The component lives in Appendix E show no change in the existing life. After incorporating these recommendations, this study recommends retaining the life of 48 years with an R2.5 dispersion. A representative graph for the life of the account is shown in the curve below.



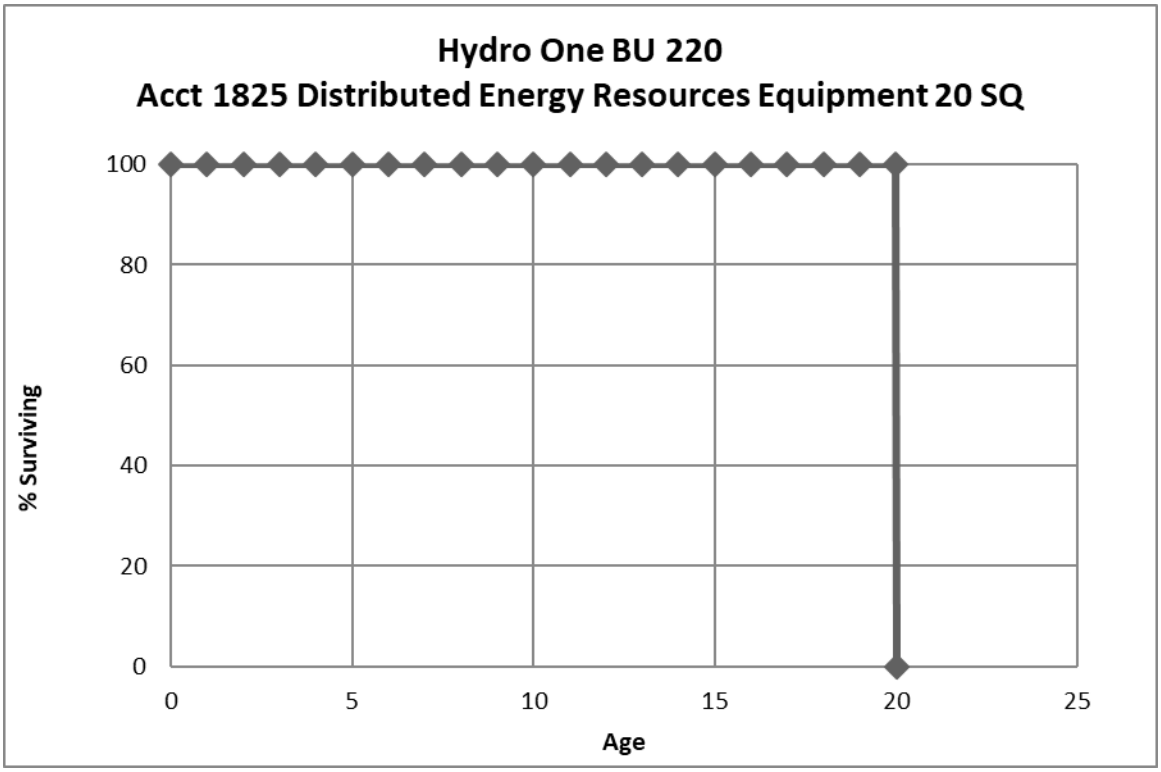
Account 1820 Distribution Station Equipment < 50 kV (48 R2.5)

This account consists of low side distribution substation equipment associated with Distribution Operations. Such assets include site improvements, foundations, fences, gates, regulators, capacitors, switching, meters units, transformers, circuit breakers, and other switchgear. The plant balance in this account at December 31, 2024 is $958.5 million. Currently, the life of this account is 45 years with an R2.5 dispersion. Limited retirement activity exists to analyze the life of the account. In Distribution operations, Company personnel state that distribution assets are more condition-based than transmission assets, meaning that they are run to failure whereas the transmission assets receive time-based maintenance. Some examples of run to failure assets in this account are: cables, service systems, switchboards, control cable, conduit, grounding systems, misc. regulators, and capacitors. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing life should be extended slightly to match Account 1815. For the reasons listed above, a 48-year life with an R2.5 dispersion is recommended for this account. A representative curve shape is shown below.


Hydro One BU 220 Account 1820
Distribution Station Equipment 48 R2.5
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
Age

Account 1825 Distributed Energy Resources ("DER") Equipment (20 SQ)

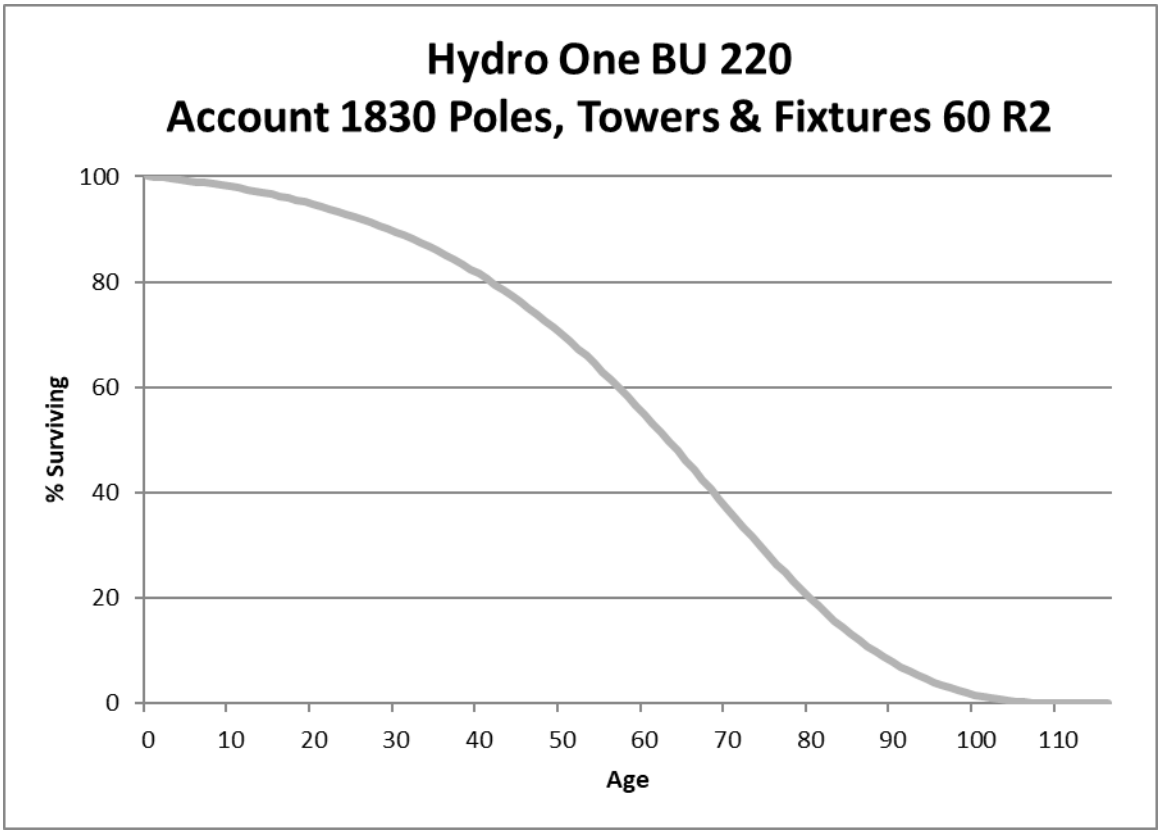
This is a new account consisting of distributed energy resources ("DER") equipment. At present, the component in this account is battery storage equipment. The plant balance in this account at December 31, 2024 is $9.1 million. This is a new account with no approved life parameter. Company SMEs recommend a 20-year life based on manufacturer expectations. Based on input from Company SMEs, a 20-year life with an SQ dispersion is recommended for this account. A representative curve shape is shown below.



Account 1830 Poles Towers and Fixtures (60 R2)

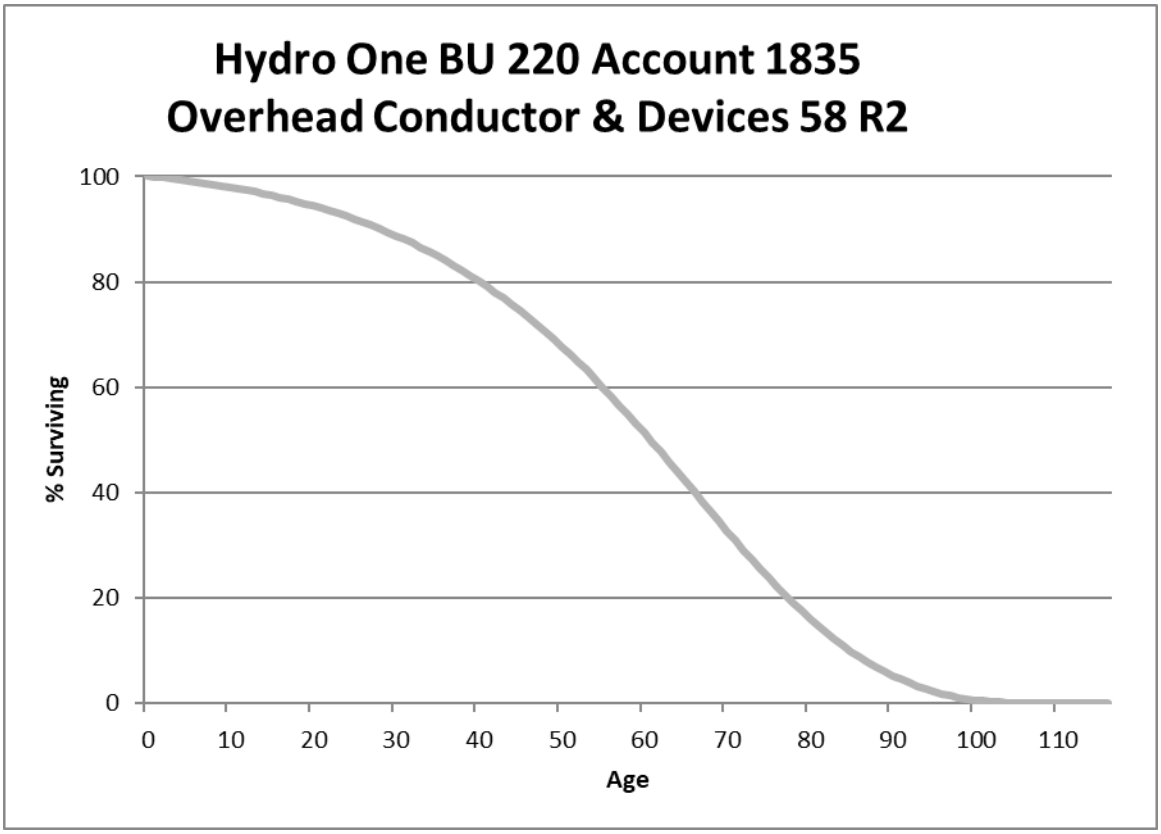
This account consists of various poles, towers, and fixtures associated with Distribution Operations. Such assets include steel towers, steel poles, supports, composite poles, and other support devices. The plant balance in this account at December 31, 2024 is $5.9 billion. Currently the life of this account is 55 years with an R2 dispersion. Limited retirement activity exists to analyze the life of the account. The pole refurbishment began in September 2020 and was suspended in early 2025. The program involved testing and ground line treatments. The target for the program was 100k units in 2020 but the Company has treated 114k units through 2023. On average, 40k units per year were treated in first 3 year of program. Due to the suspension of the program the first cycle will take longer.

Previous programs focused more on visual inspection, and test and treat programs were not done from 2009 to 2020. Approximately 90% of Hydro One's poles are wood. Hydro One's service territory is more rural and they have many poles with CCA treatment. The treatment program stopped in the early 2000s, but has resumed. Company SMEs advise that a slightly longer life is operationally reasonable. Since this is a fairly new initiative, based on input from Company experts, this study recommends moving to a 60-year life with an R2 dispersion. A representative curve shape is shown below.


Hydro One BU 220
Account 1830 Poles, Towers & Fixtures 60 R2
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
Age

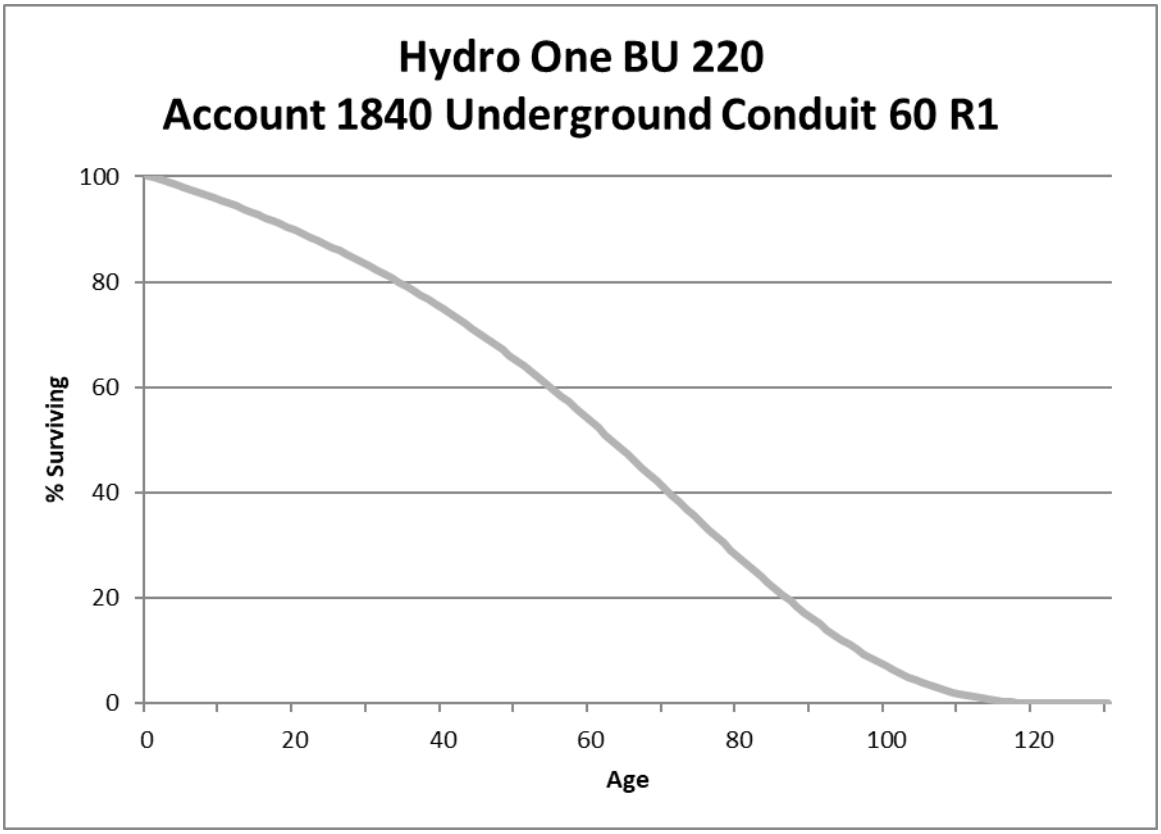
Account 1835 Overhead Conductor and Devices (58 R2)

This account consists of overhead conductor and devices associated with Distribution Operations. Such assets include grounding systems, ground wires, insulators, conductor, switches, voltage regulators, and capacitors. The plant balance in this account at December 31, 2024 is $2.2 billion. Currently, the life of this account is 55 years with an R2 dispersion. Limited retirement activity exists to analyze the life of the account. Company experts state that there are many reasons to replace conductor, including replacement due to sags or capacity. The Company is using more electronic devices that experts believe will have a shorter life than the mechanical switches used in the past. Electronic devices are approximately 5 percent of the total in Hydro One. There are approximately 135 switches and 220 devices with reclosers and switches. Considering the various assets in the account, this study recommends a 58-year life with an R2 dispersion for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220 Account 1835
Overhead Conductor & Devices 58 R2
% Surviving
100
80
60
40
20
0
0
10
20
30
40
50
60
70
80
90
100
110
Age

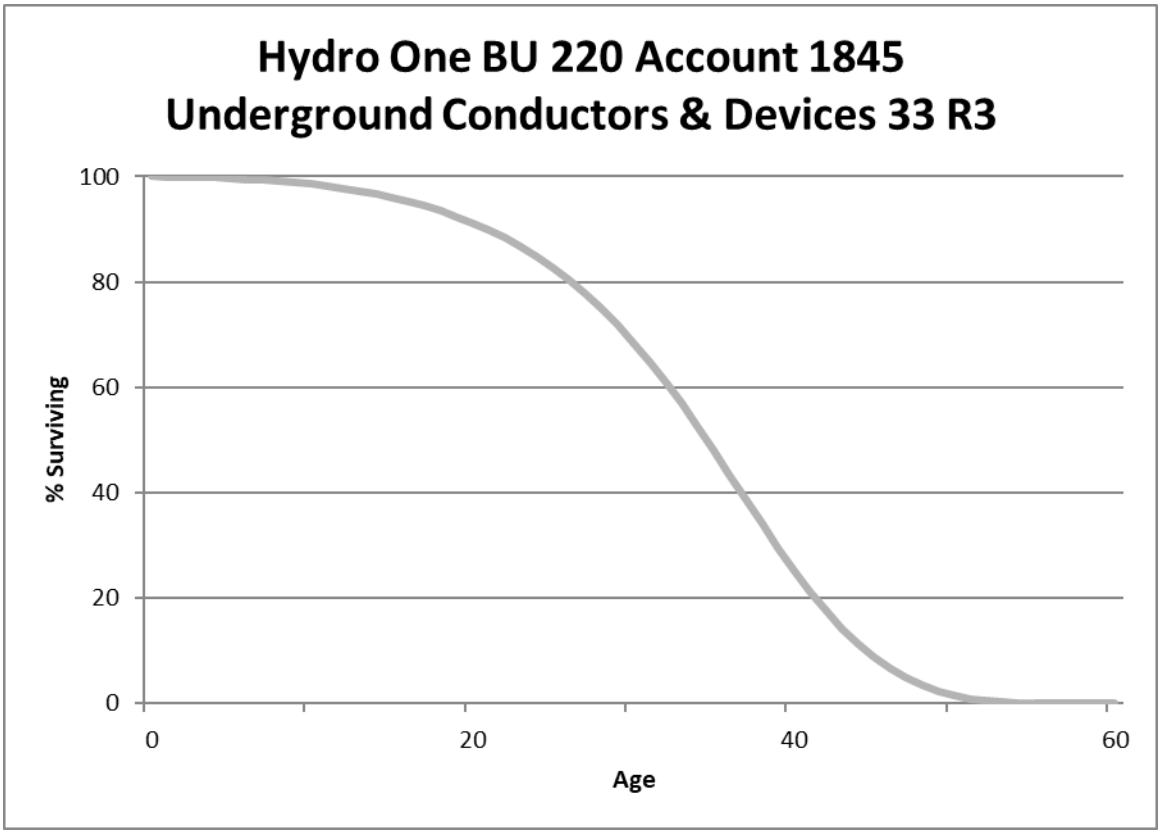
Account 1840 Underground Conduit (60 R1)

This account consists of underground conduit associated with Distribution Operations. The plant balance in this account at December 31, 2024 is $32.8 million. Currently, the life of this account is 60 years with an R1 dispersion. Limited retirement activity exists to analyze the life of the account. Company personnel report that conduit is found primarily in substation entries and in urban areas. Company experts believe higher levels of conduit will be installed in the future. Operations personnel report that material quality has improved in recent years with changes in specifications. Company personnel report that they generally run a spare conduit with installations, so that it is possible to pull and replace in same duct. After seeking input from Company SMEs and incorporating professional judgment, the determination was that the existing life remains appropriate. For the reasons listed above, retention of the 60-year life with an R1 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1840 Underground Conduit 60 R1
% Surviving
100
80
60
40
20
0
0
20
40
60
80
100
120
Age

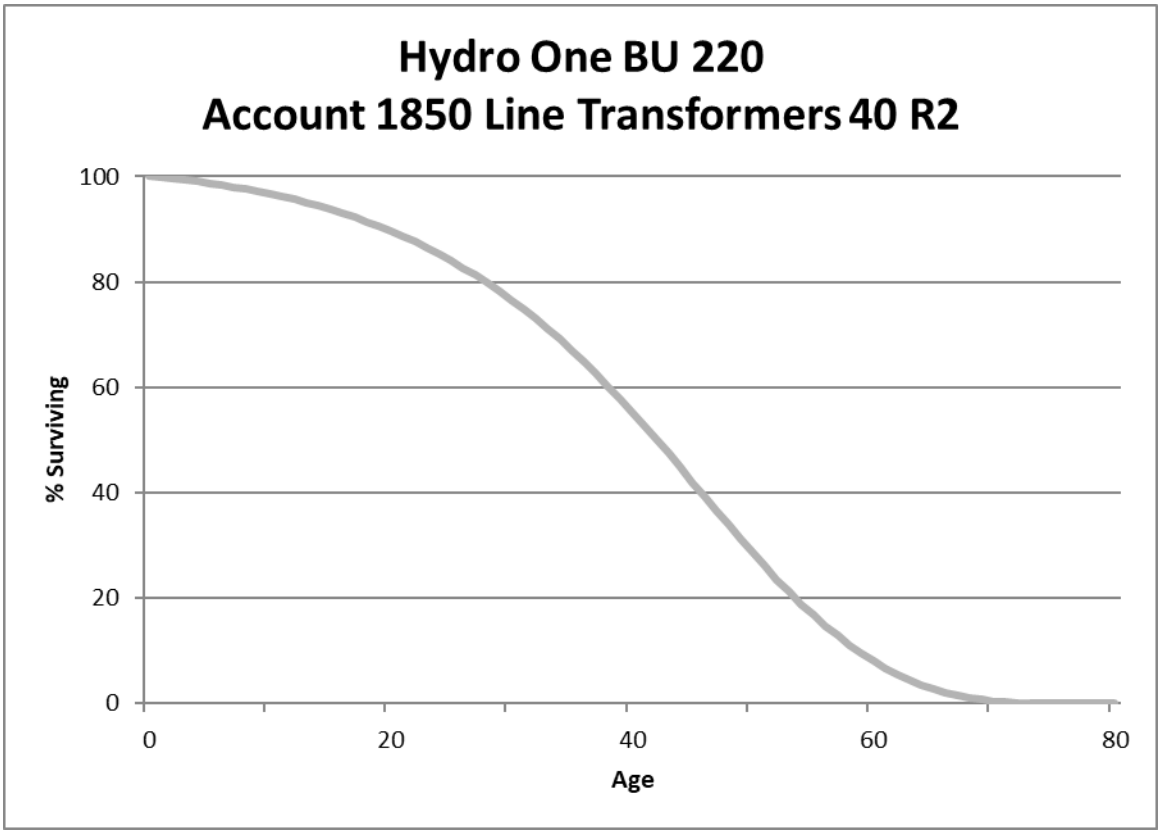
Account 1845 Underground Conductors and Devices (33 R3)

This account consists of various underground conductor and devices associated with Distribution Operations. Such assets include underground conductor, submarine cable, and fuse housing. The plant balance in this account at December 31, 2024 is $984.1 million. Currently, the life of this account is 33 years with an R3 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs report that most conductor is direct buried and will last a shorter period than overhead conductor. The reasons that conductor fails include insulation breaking down and dig-ins. In the Ontario environment, conductor has a much shorter life than conduit. The Company is piloting a cable cure program, which has not been used in the past. Company personnel believe that new conductor will last slightly longer than older assets and as larger quantities of the newer material are placed on the system, the average life may begin to increase at some point in the future. After seeking input from Company personnel and incorporating professional judgment, the determination was that the life should be retained for this account. For the reasons listed above, retention of the 33-year life with an R3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220 Account 1845
Underground Conductors & Devices 33 R3
% Surviving
100
80
60
40
20
0
0
20
40
60
Age

Account 1850 Line Transformers (40 R2)

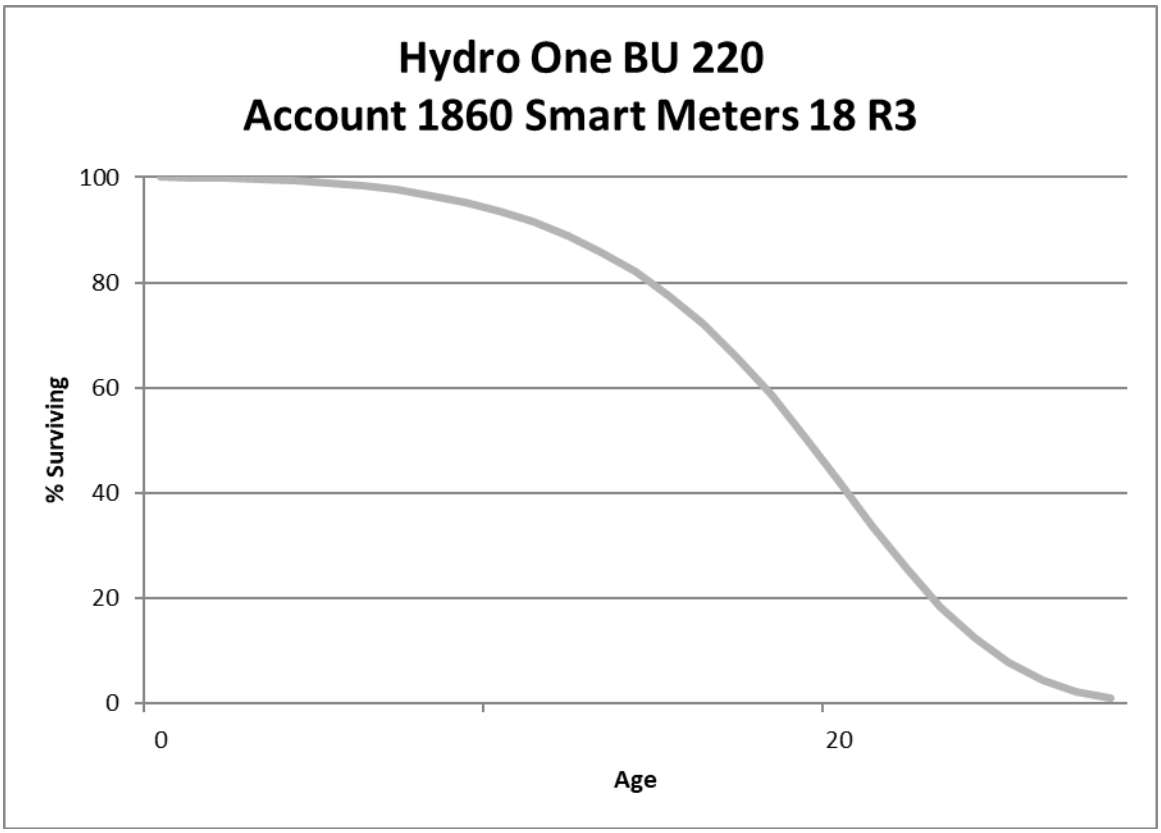
This account consists of various types of line transformers associated with Distribution Operations. Such assets include overhead transformers, underground transformers, capacitors, and other similar equipment. The plant balance in this account at December 31, 2024 is $2.2 billion. Currently, the life of this account is 40 years with an R2 dispersion. Limited retirement activity exists to analyze the life of the account. Company SMEs report that they replaced virtually all PCB transformers with PCB levels of 50 parts per million or above. They estimate that about 1-4% of the transformers have been impacted by the change out. Company personnel report that most replacements are approximately 40 years old. The Company runs a transformer until it fails, and no repair program is currently in place. Operations personnel report that the life of the transformer depends on its loading. Hydro One is loading transformers at around the same level as in the past. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 40-year life is still appropriate for this account. For the reasons listed above, retaining a 40-year life with an R2 dispersion is recommended for this account. A representative graph for this account is shown below.


Hydro One BU 220
Account 1850 Line Transformers 40 R2
100
80
60
40
20
0
% Surviving
0
20
40
60
80
Age

Account 1860 Smart Meters Later Generation (18 R3)

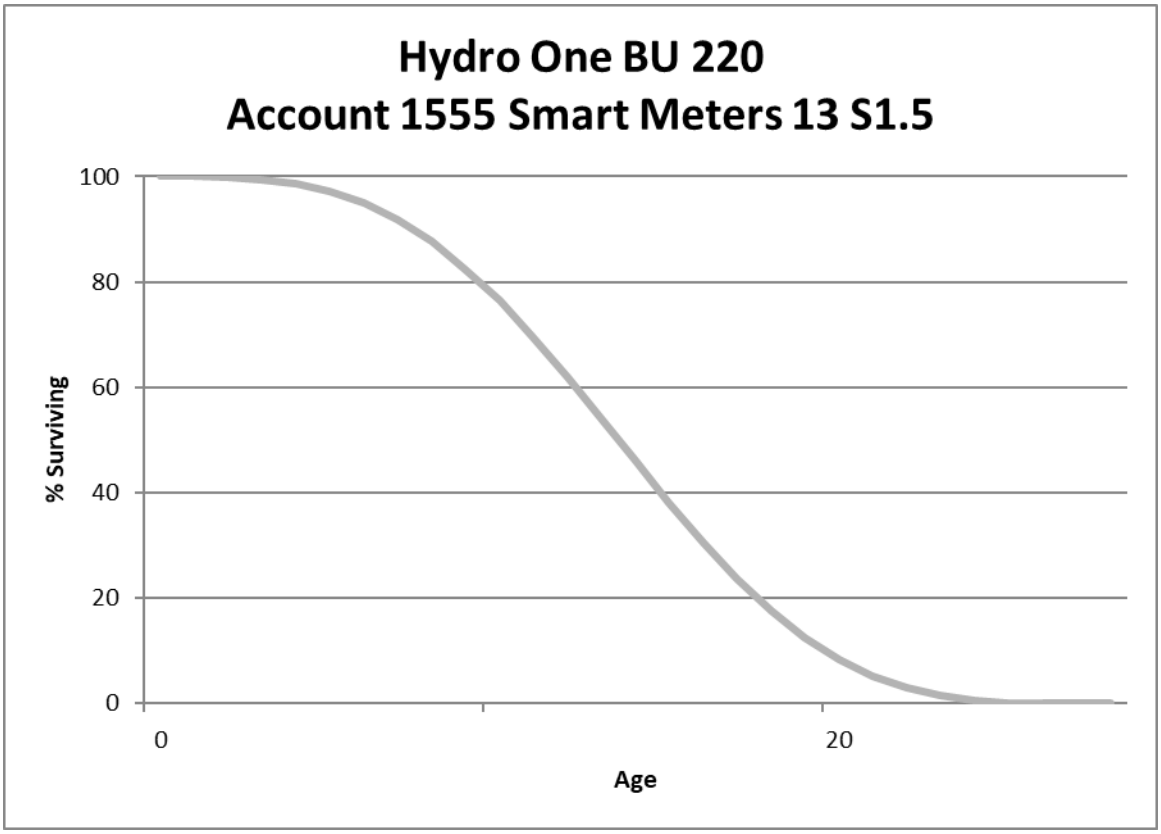
Account 1860 consists of various meters associated with Distribution Operations. Such assets include watt meters, demand meters, and all other meter equipment. The plant balance in this account at December 31, 2024 is $839.4 million. These meters are part of the new meter deployment project, Gen 5 Reva 900 MH Solution. The Company has a deployment schedule from 2022-2029. After examining a deployment schedule provided by the Company, the average age is estimated to be 17.594 years. The Company plans to replace AMI 1 with AMI 1 meters until the AMI 2 network is developed sufficiently to replace with AMI 2 meters.

For the reasons listed above, an 18-year life with an R3 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.



Account 1555 First Generation Smart Meters (13 S1.5)

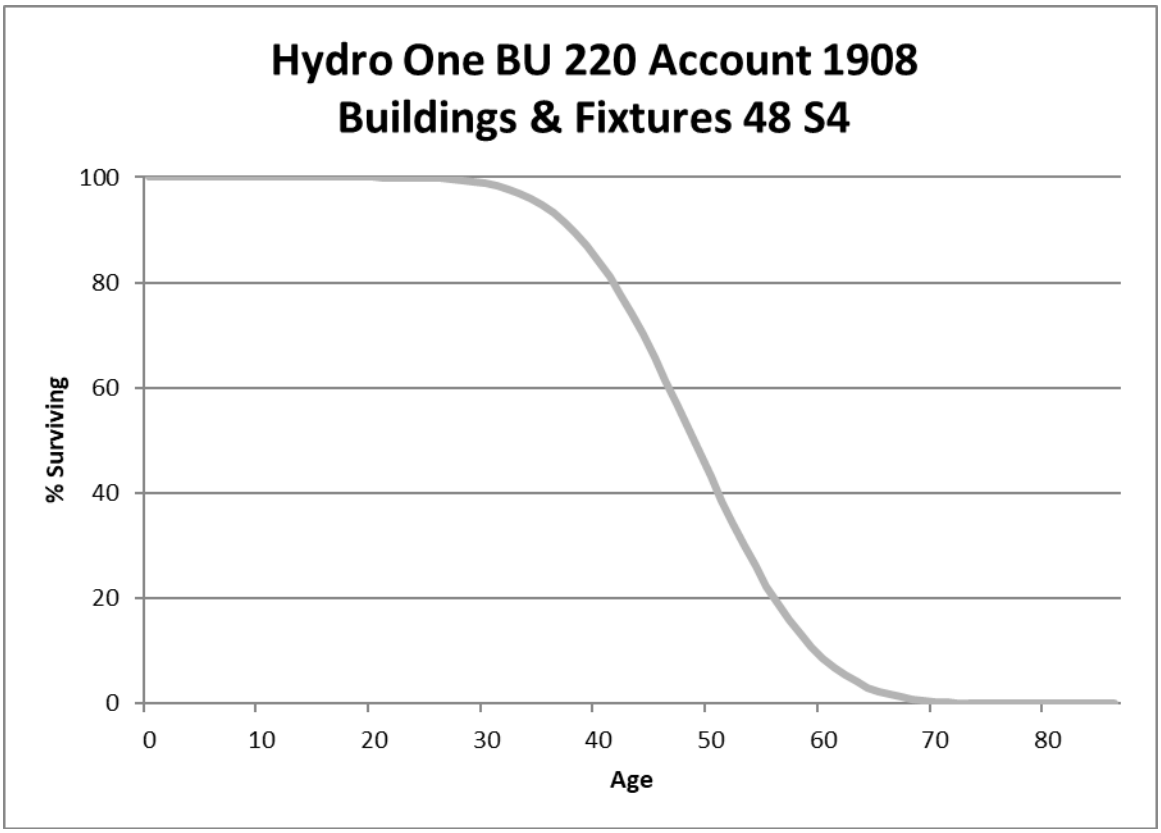
Account 1555 consists of various meters associated with Distribution Operations. Such assets include watt meters, demand meters, and all other meter equipment that were installed in Hydro One's initial AMI project The plant balance in this account at December 31, 2024 is $295.2 million, and these assets were installed between 2007-2015. Currently, the life of this account is 18 years with an R3 dispersion. Hydro One began the move to smart meters in 2007. The meter fleet changed between 2007 and 2014, and the 15-year life used was from vendor information. Ontario was one of the first jurisdictions to completely switch to smart meters. The first generation smart meters had a defect that caused the early retirement of over 100 meters. Routinely, first generation meters would be replaced on the magnitude of 50-60 thousand meters per year due to communication issues. A 13-year life from history would be reasonable for AMI 1 meters. For the reasons listed above, a 13-year life with an S1.5 dispersion is recommended for this account. A representative graph for the life of the account is shown in the curve below.


Hydro One BU 220
Account 1555 Smart Meters 13 S1.5
100
80
60
40
20
0
% Surviving
0
20
Age

GENERAL DEPRECIATED FUNCTIONAL GROUP

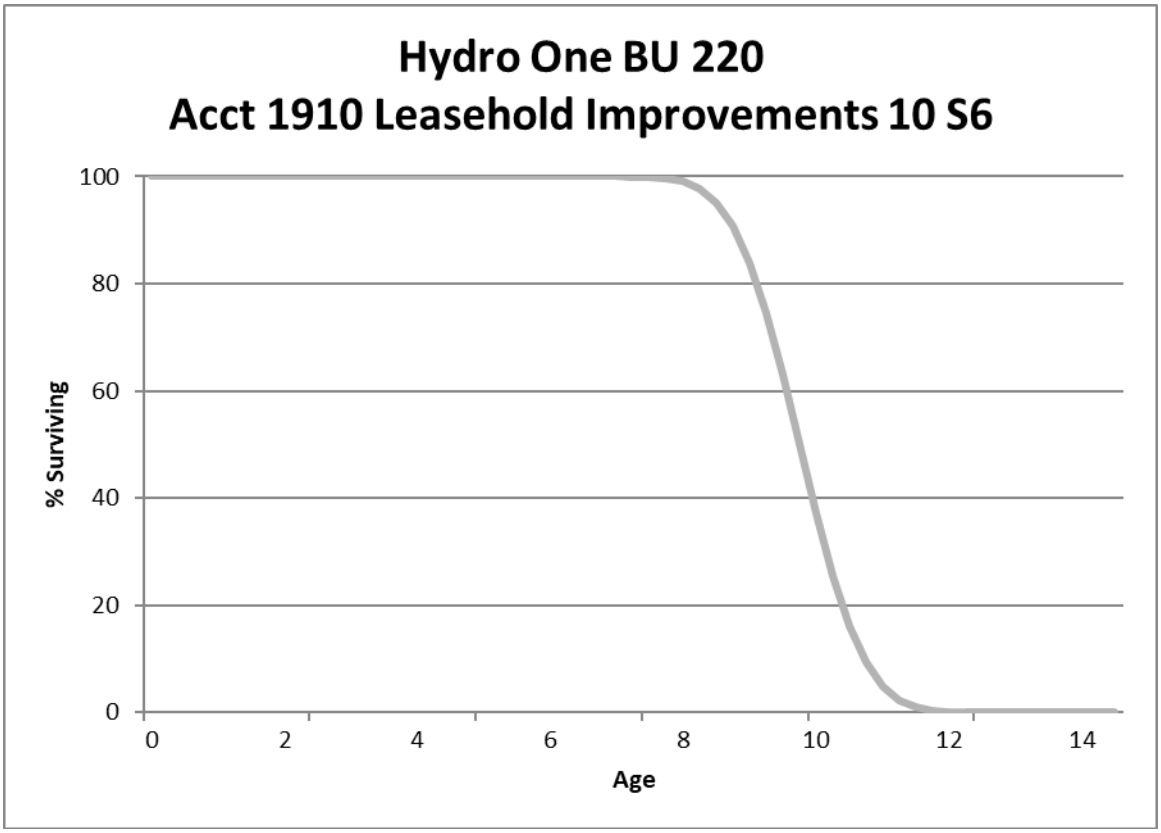
Account 1908 Buildings and Fixtures (48 S4)

This account consists of various buildings and fixtures associated with Distribution Operations. Such assets include distribution station buildings, landscaping, and other station structures. The plant balance in this account at December 31, 2024 is $267.2 million. Currently the life of this account is 50 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. The component lives shown in Appendix E show a slight change in the composite life for one of the components moving the component life for roads and surfaces from 50 years to 25 years in this study. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50-year life should be slightly decreased. This study recommends moving to a 48-year life with an S4 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



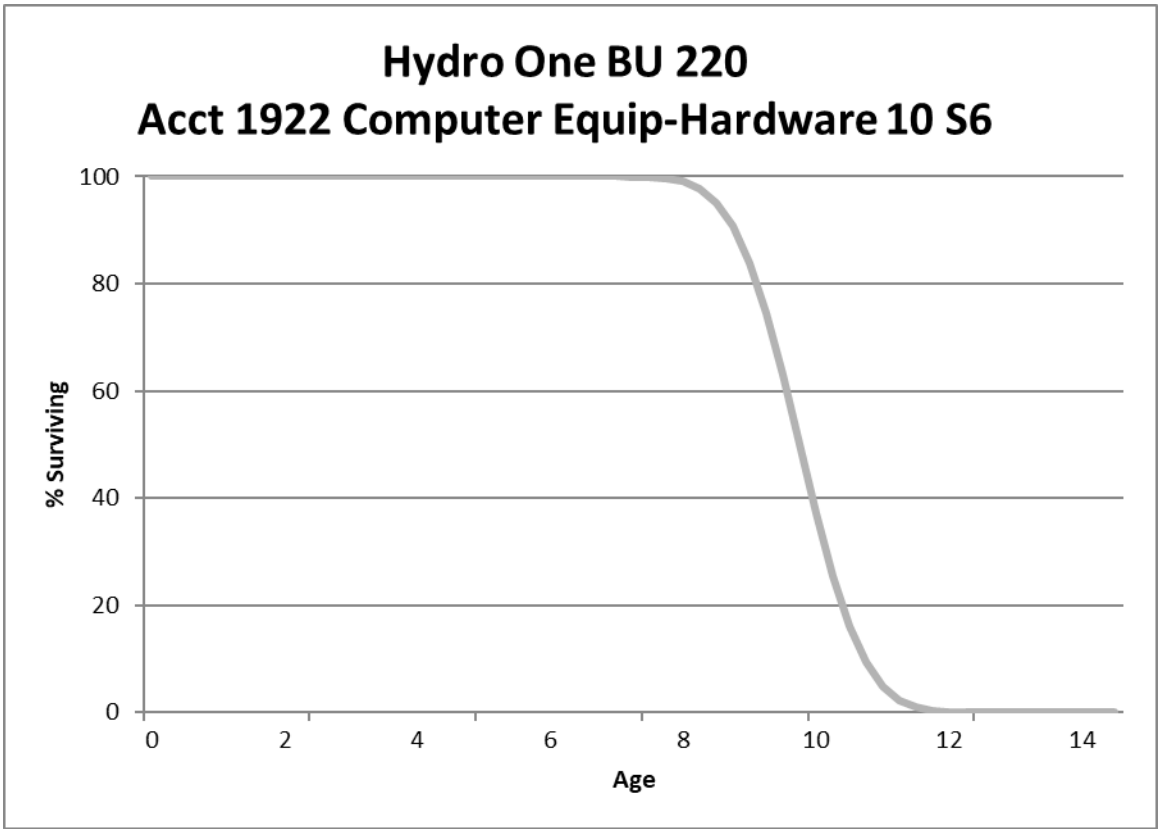
Account 1910 Leasehold Improvements (10 S6)

This account consists of various leasehold improvements made to leased buildings associated with Distribution Operations. The plant balance in this account at December 31, 2024 is $18.0 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. This study recommends retention of a 10-year life with an S6 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



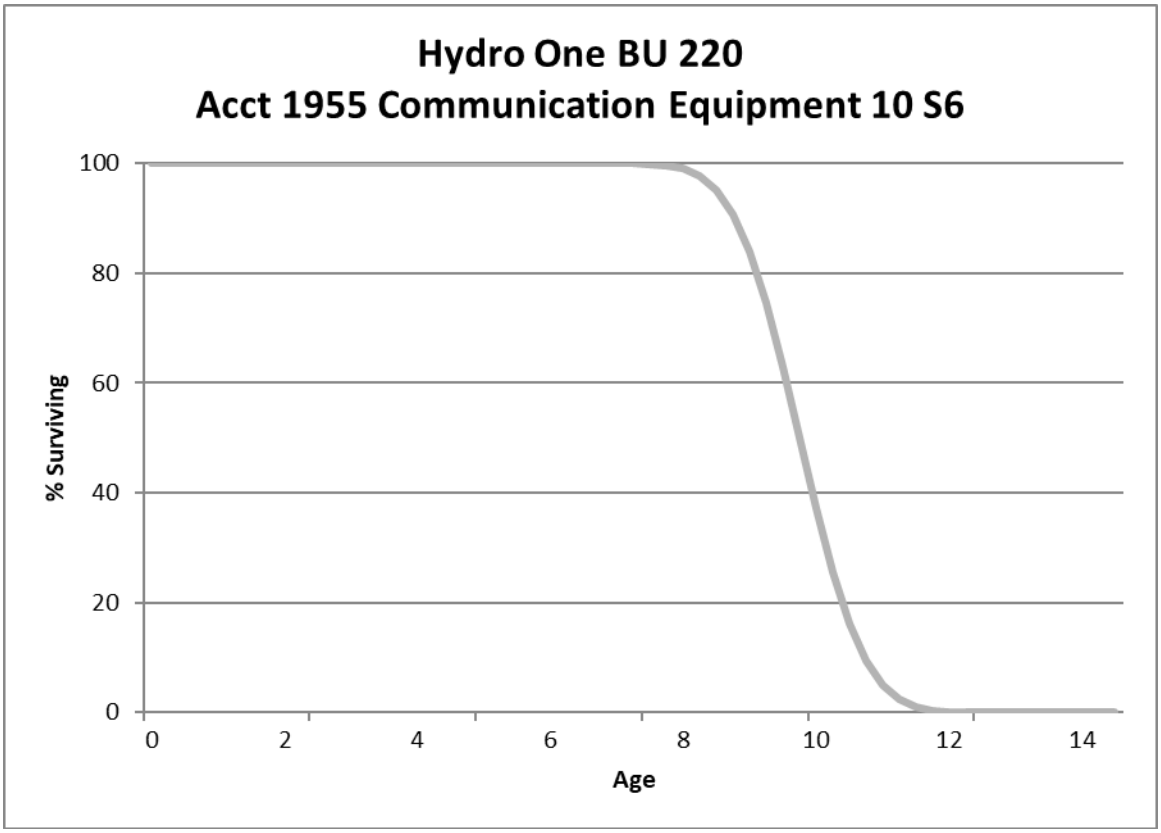
Account 1922 Computer Equipment - Hardware (10 S6)

This account consists of various computer hardware equipment associated with Distribution Operations. Such assets include local area network wire and devices and fiber optic cable. The plant balance in this account at December 31, 2024 is $4.7 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. This study recommends retention of a 10-year life with an S6 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



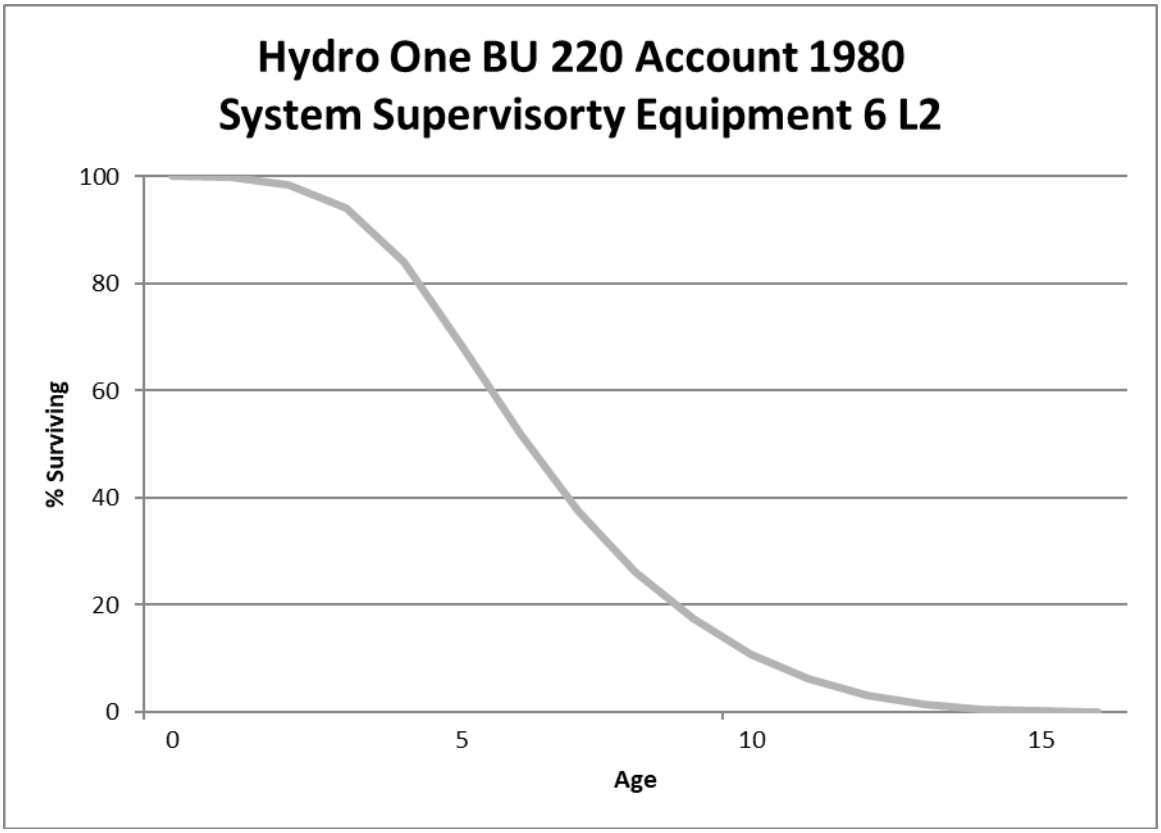
Account 1955 Communication Equipment (10 S6)

This account consists of various type of communication equipment associated with Distribution Operations. Such assets include fiber optic equipment, telecom equipment, radio equipment, and wire and power supply equipment. The plant balance in this account at December 31, 2024 is $29.7 million. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 7-year life should be slightly increased for this account. This study recommends moving to a 10-year life with an S6 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



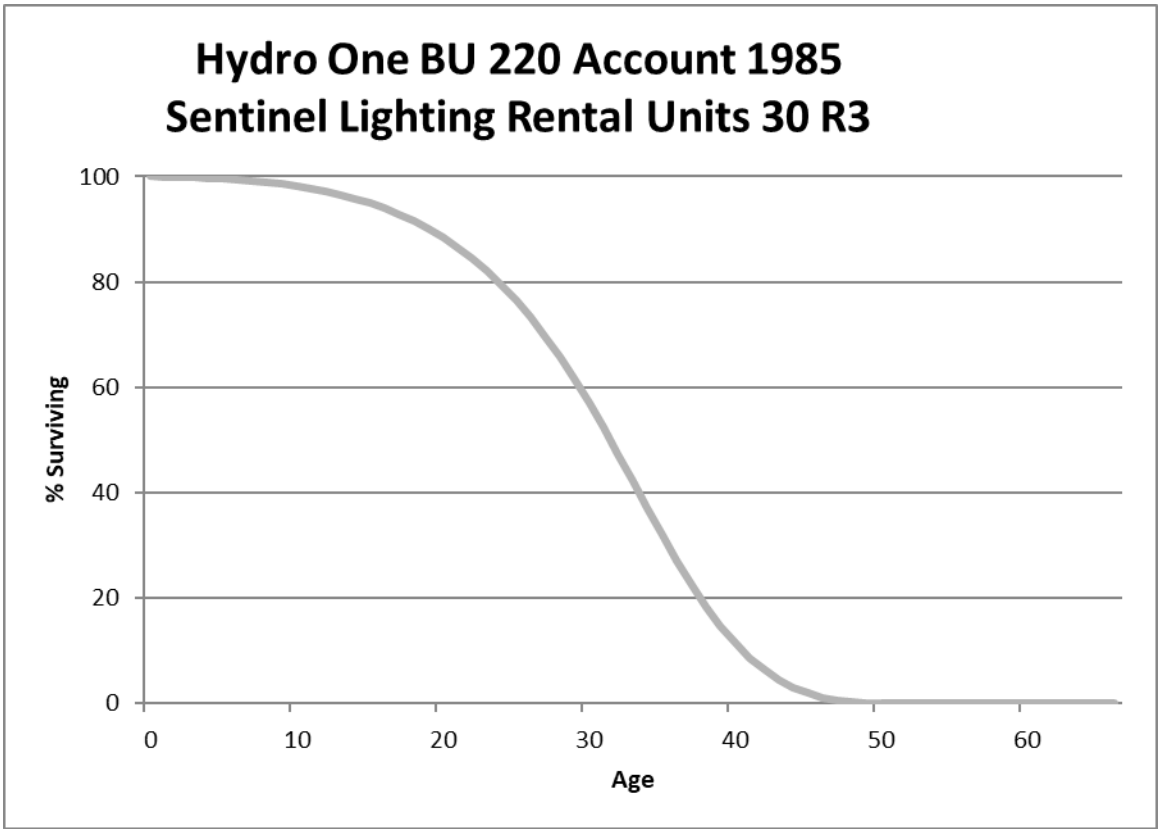
Account 1980 System Supervisory Equipment (6 L2)

This account consists of system supervisory equipment associated with Distribution Operations. Such assets include power lines, computer equipment, and related software. The plant balance in this account at December 31, 2024 is $134.2 million. Currently, the life of this account is 6 years with an L2 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 6-year life is still appropriate for this account. This study recommends retention of a 6-year life with an L2 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



Account 1985 Sentinel Lighting Rental Units (30 R3)

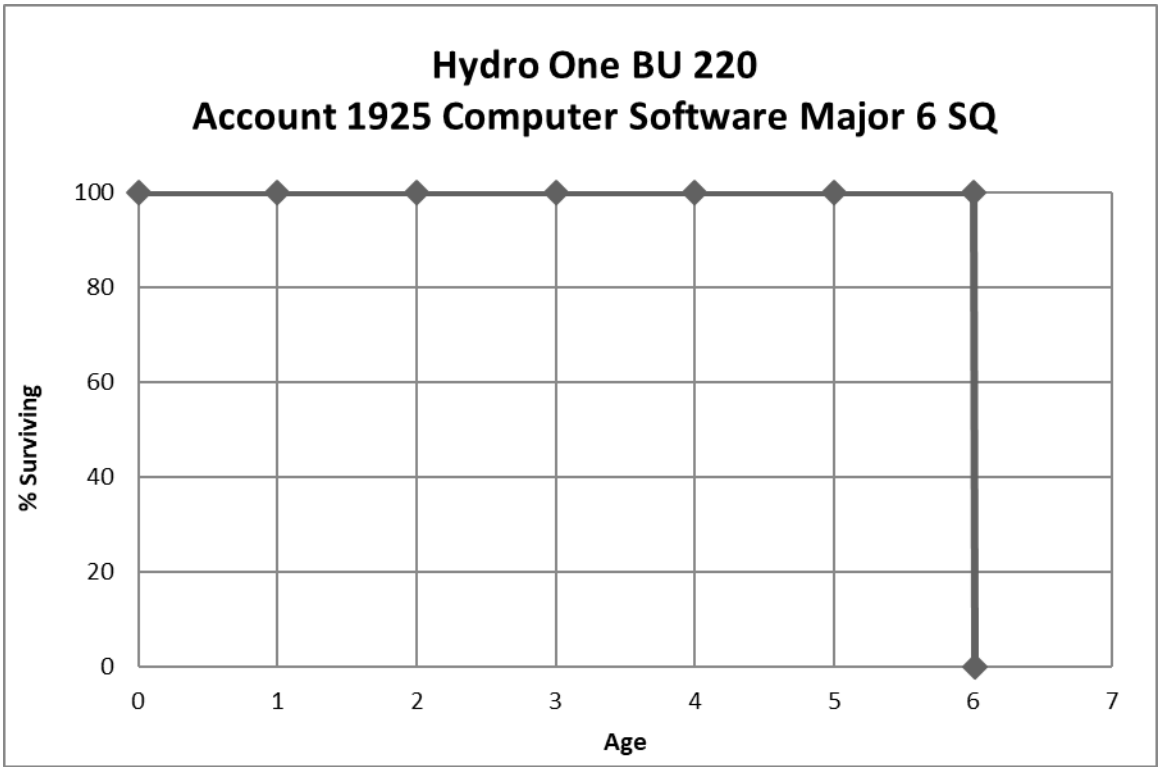
This account consists of sentinel lighting units with Distribution Operations. The plant balance in this account at December 31, 2024 is $15.4 million. Currently, the life of this account is 27 years with an R3 dispersion. Given that retirement activity has been minimal, Company SMEs recommend a slight increase in the life. After seeking input from Company personnel, reviewing the analysis and incorporating professional judgment, the determination was that the existing year life should be extended from its current level. This study recommends a 30-year life with an R3 dispersion for this account. A representative graph for the life of the account is shown in the curve below.



GENERAL AMORTIZED FUNCTIONAL GROUP

Account 1925 Computer Software (6 SQ)

This account consists of computer software for the Distribution Operations group. Such assets include general system software. The plant balance in this account at December 31, 2024 is $2.4 million. Currently, the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative graph of the life of the account is shown in the curve below, a 6-year life with an SQ dispersion.



BU 300 COMMON OPERATIONS

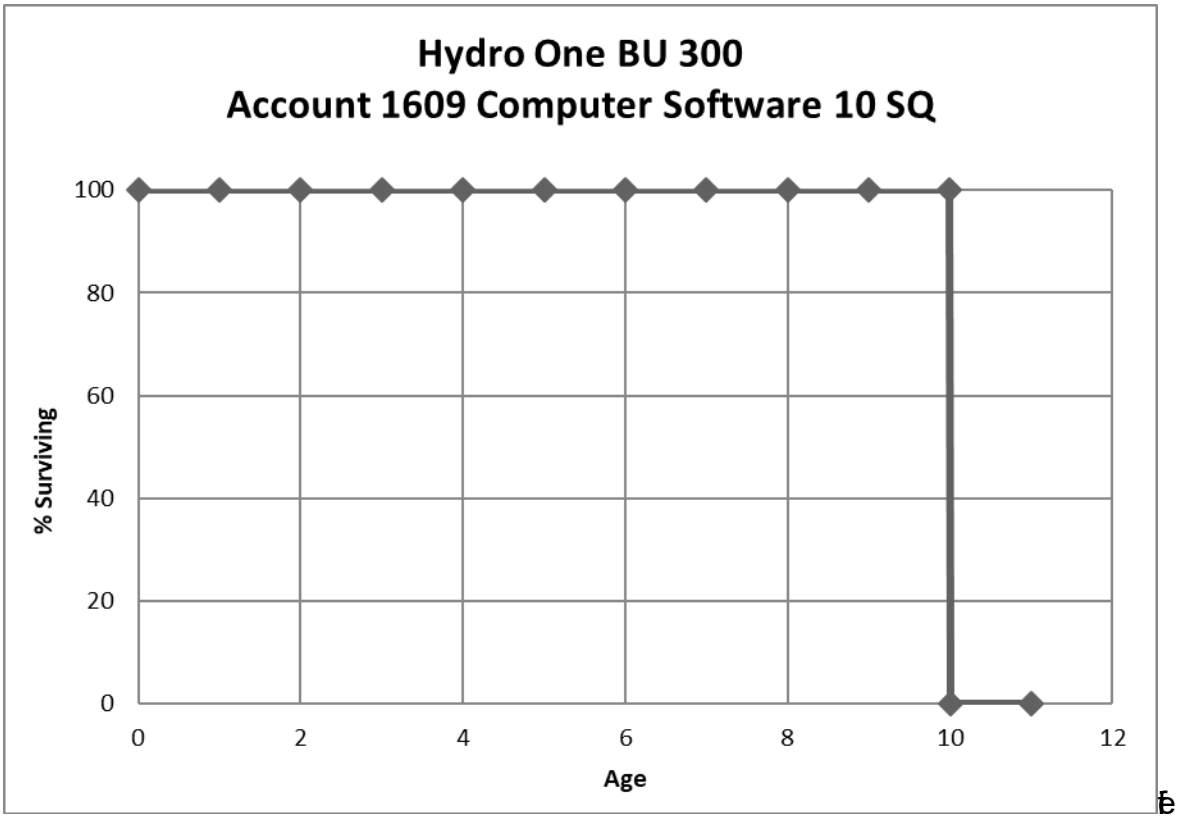
Common assets serve both the Transmission and Distribution Operations groups. The costs are allocated between each business unit.

INTANBIGLE FUNCTIONAL GROUP

Accounts in the intangible function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the assigned life of the account.

Account 1610 Computer Software (10 SQ)

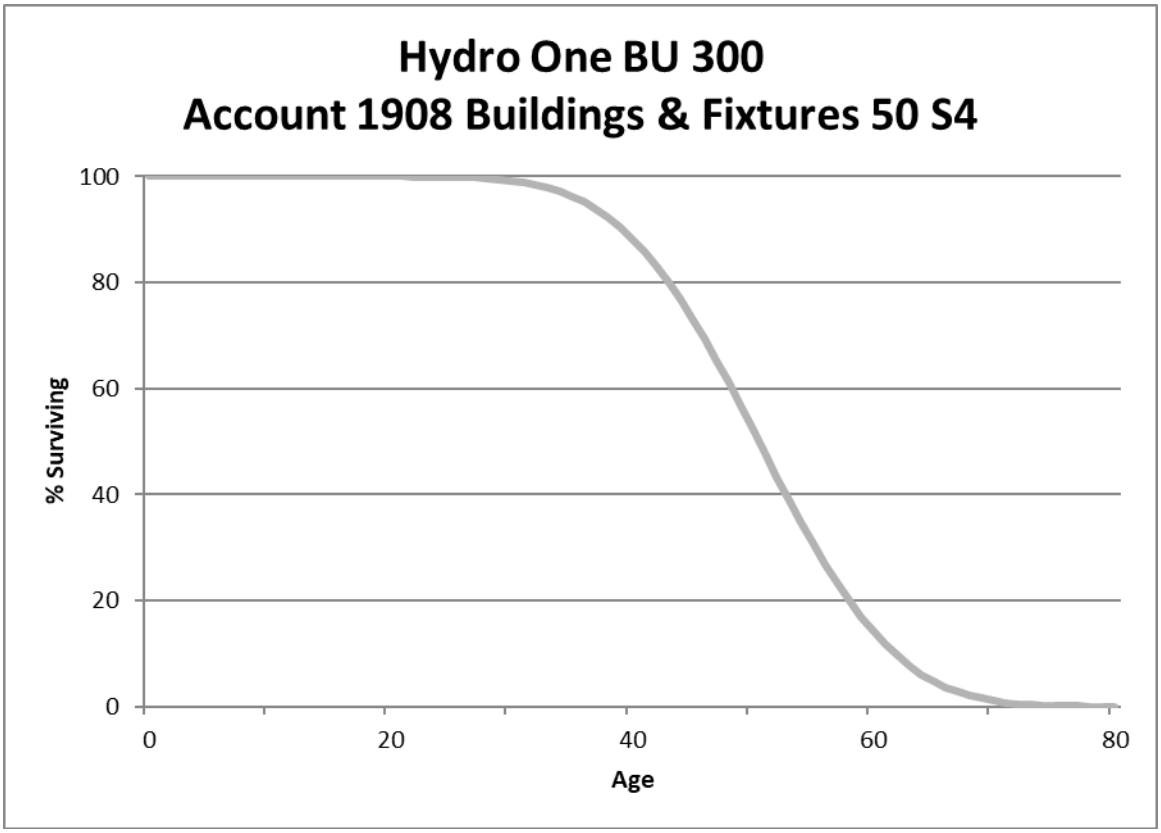
This account consists of computer software for general operations. Such assets include general system software. The plant balance in this account at December 31, 2024 is $580.3 million. Currently, the amortization life of this account is 12 years. The Company's major enterprise and cornerstone systems are booked in the account and allocated to transmission and distribution. Some of the systems are nearly 10 years old at this time with significant upgrades planned in the future. Given the continued use of these systems and forthcoming upgrades, a slightly shorter life is recommended in this account. After reviewing plant lives with Company personnel, the determination was that moving to a 10-year life is appropriate for this account. A representative graph of proposed curve shape is shown below.


Hydro One BU 300
Account 1609 Computer Software 10 SQ
% Surviving
100
80
60
40
20
0
0
2
4
6
8
10
12
Age

GENERAL DEPRECIATED FUNCTIONAL GROUP

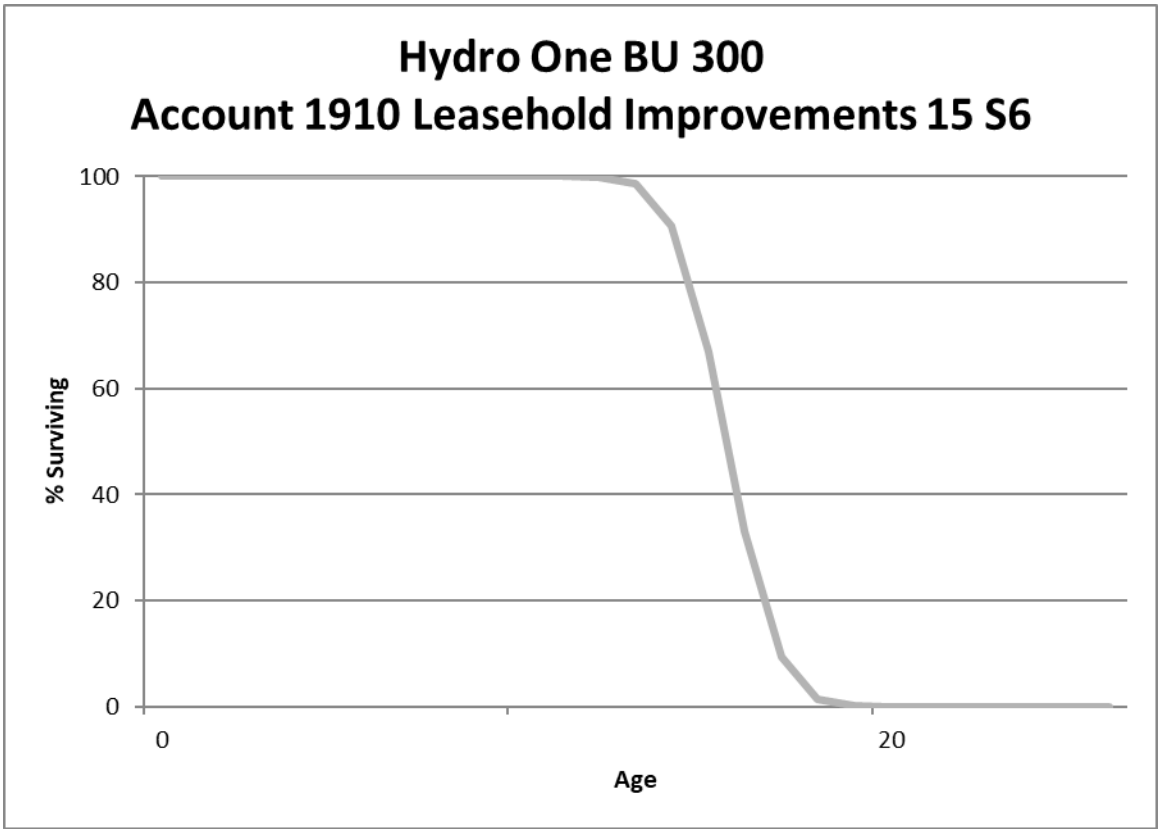
Account 1908 Buildings and Fixtures (50 S4)

This account consists of various general buildings and fixtures associated with Transmission and Distribution Operations. Such assets include buildings, road and surfaces, fences, auxiliary buildings, and road and surface areas. The plant balance in this account at December 31, 2024 is $309.6 million. Currently, the life of this account is 50 years with an S4 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 50-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 50-year life with an S4 dispersion.



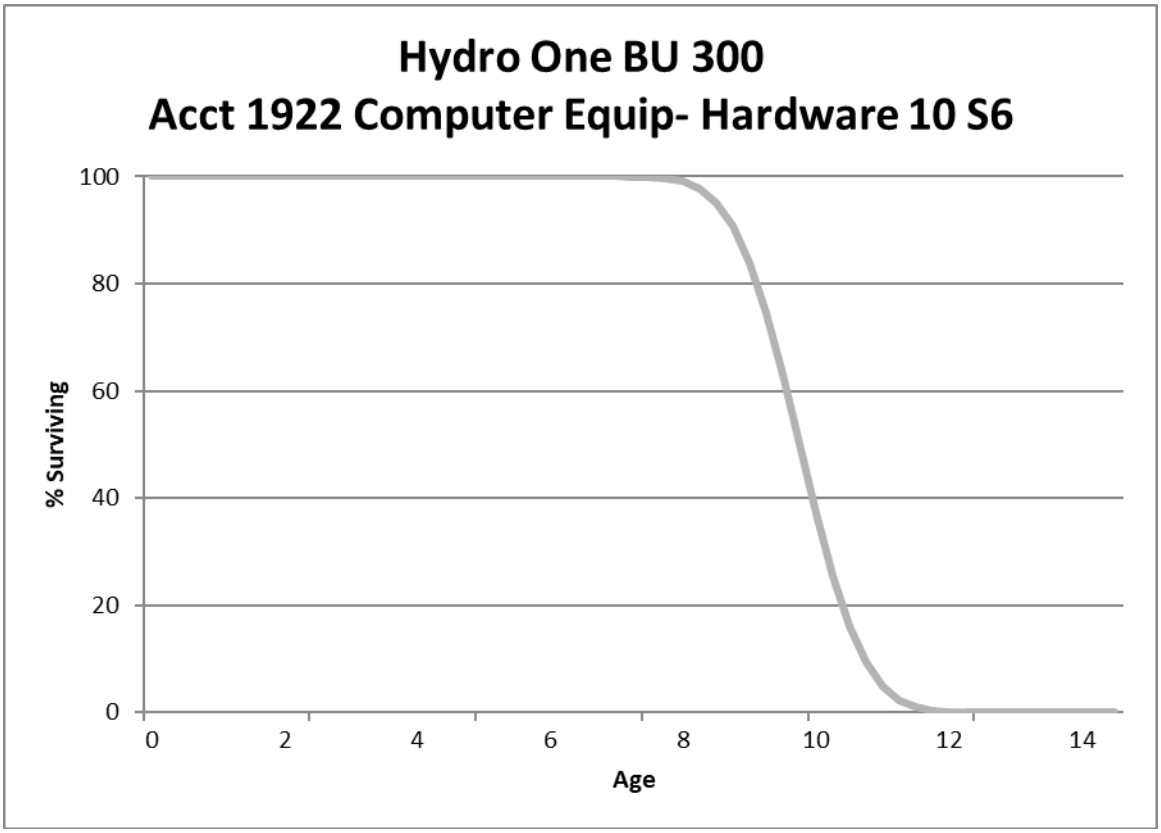
Account 1910 Leasehold Improvements (15 S6)

This account consists of various general leasehold improvements made to leased buildings associated with Transmission and Distribution Operations. The plant balance in this account at December 31, 2024 is $48.9 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that a slight life extension is operationally reasonable for this account. Based on input from Company SMEs, a life of 15 years with an S6 dispersion is proposed for this account. A representative graph for the life of the account is shown in the curve below, a 15-year life with an S6 dispersion.



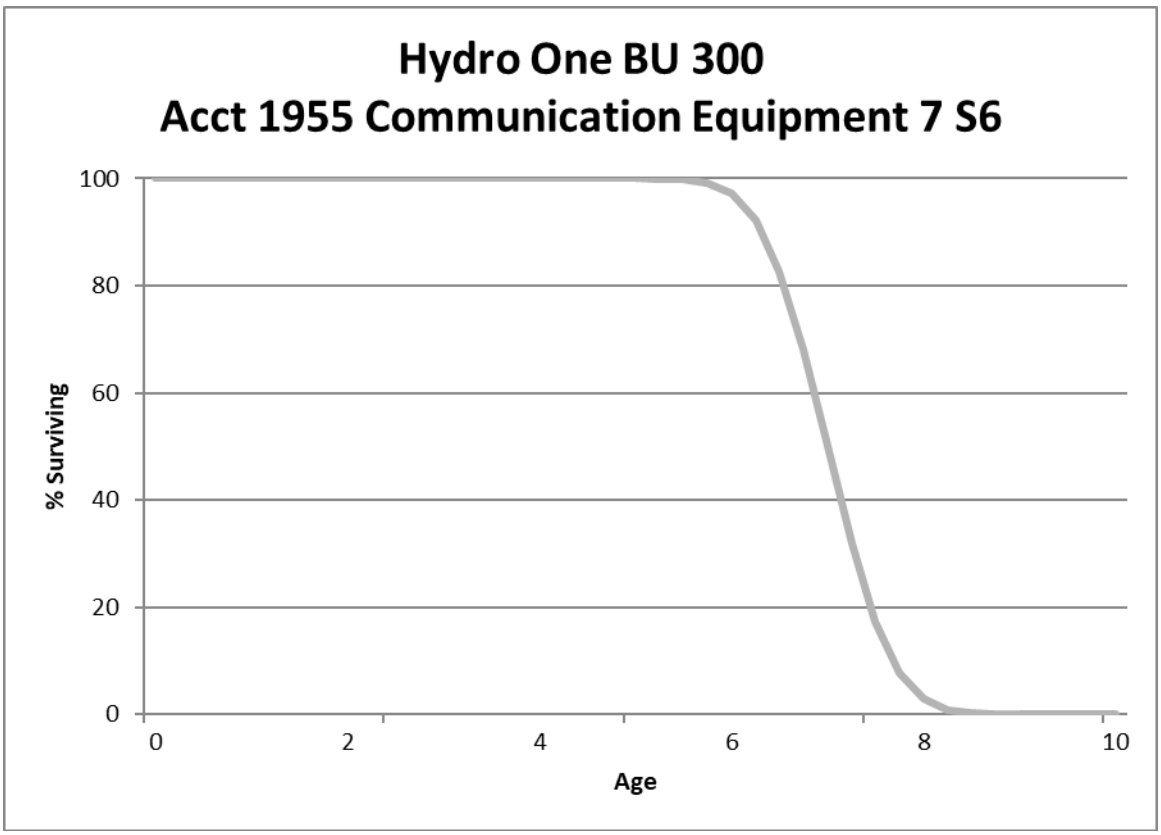
Account 1922 Computer Equipment - Hardware (10 S6)

This account consists of general computer hardware associated with Transmission and Distribution Operations. Such assets include local area network devices and cable. The plant balance in this account at December 31, 2024 is $53.1 million. Currently, the life of this account is 10 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 10-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 10-year life with an S6 dispersion.



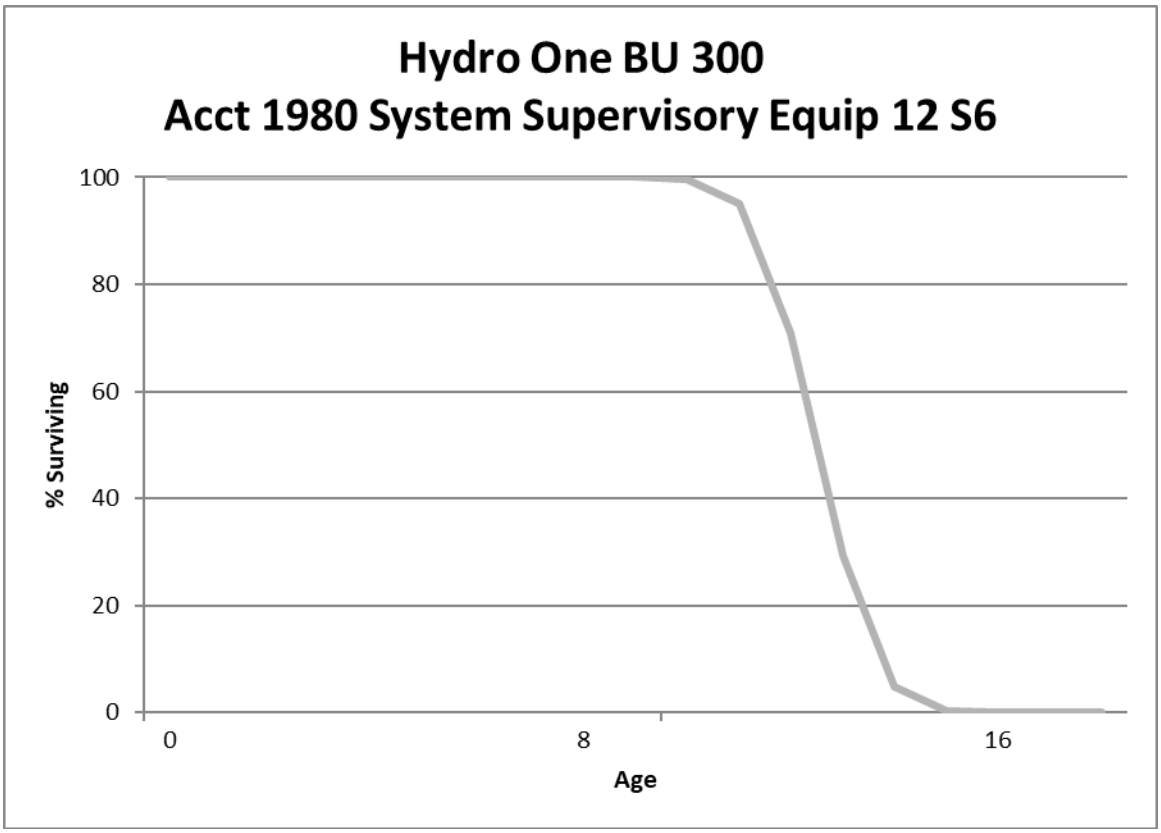
Account 1955 Communication Equipment (7 S6)

This account consists of various general communication equipment associated with Transmission and Distribution Operations. Such assets include telecom wire and equipment and radio equipment. The plant balance in this account at December 31, 2024 is $22.4 million. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing 7-year life is still appropriate for this account. A representative graph for the life of the account is shown in the curve below, a 7-year life with an S6 dispersion.



Account 1980 System Supervisory Equipment (12 S6)

This account consists of general system supervisory equipment associated with Transmission and Distribution Operations. Such assets include power line equipment, hardware, and computer software. The plant balance in this account at December 31, 2024 is $19.7 million. This account includes items such as computer, storage, network hardware, tablets, uninterruptible power supply, UPS batteries, and system and application software. Currently, the life of this account is 7 years with an S6 dispersion. Limited retirement activity exists to analyze the life of the account. After seeking input from Company personnel and incorporating professional judgment, the determination was that the existing year life is too short. This study recommends a longer life of 12 years with an S6 dispersion. A representative graph for the life of the account is shown in the curve below.

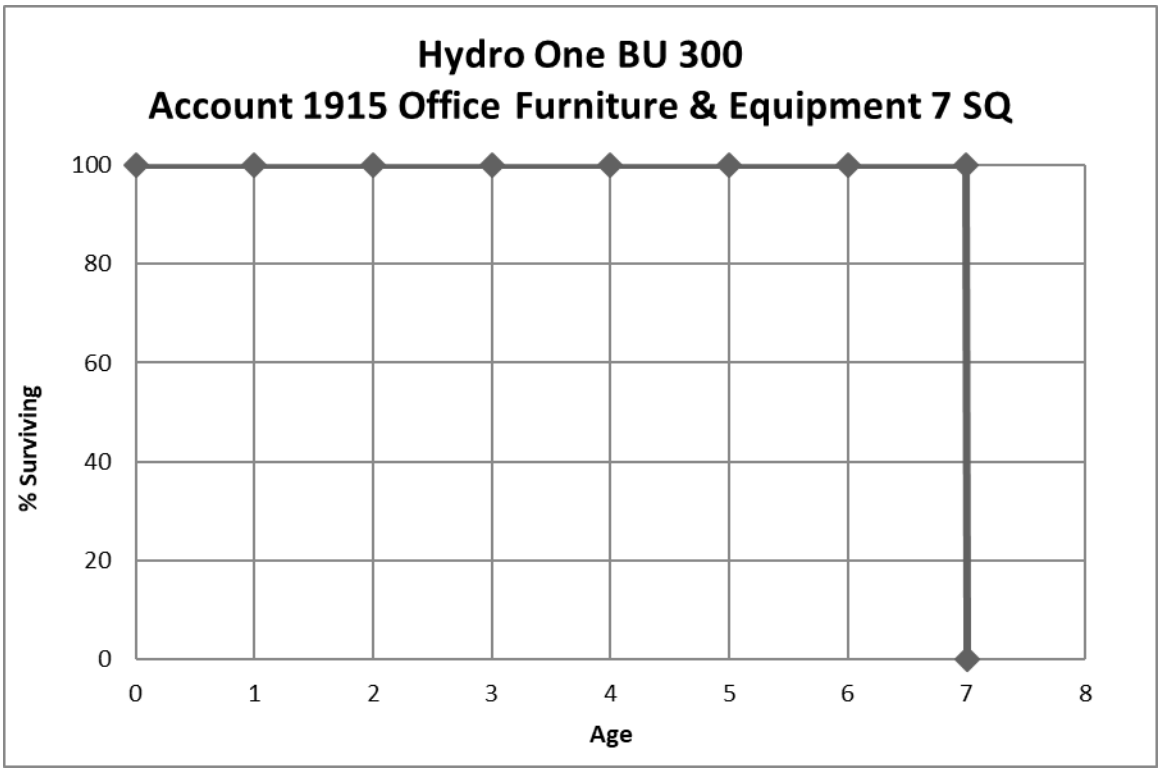


GENERAL AMORTIZED FUNCTIONAL GROUP

Accounts in the general amortized function are amortized. When those assets are fully accrued amortization ceases. Any new assets added are amortized using the assigned life of the account.

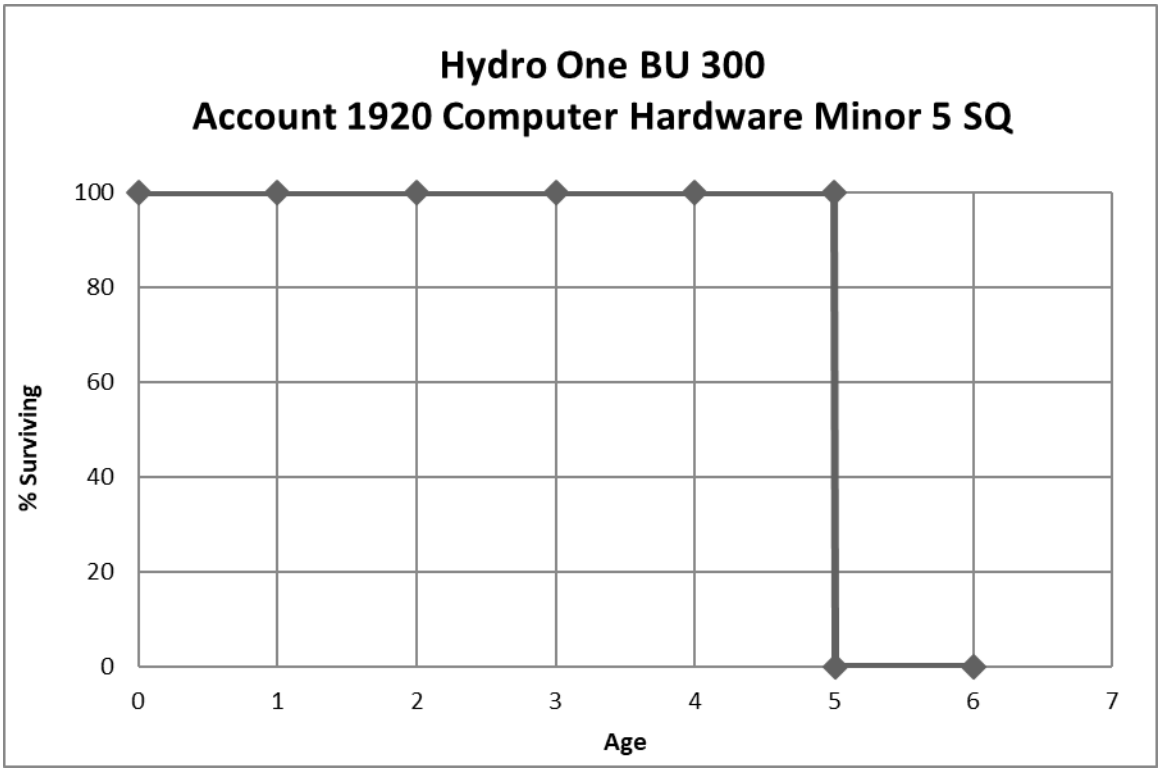
Account 1915 Office Furniture and Equipment (7 SQ)

This account consists of general office furniture and equipment. Such assets include desks, chairs, filing cabinets, etc. The plant balance in this account at December 31, 2024 is $6.7 million. Currently, the amortization life of this account is 7 years. After reviewing plant lives with Company personnel, the determination was that the existing 7-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



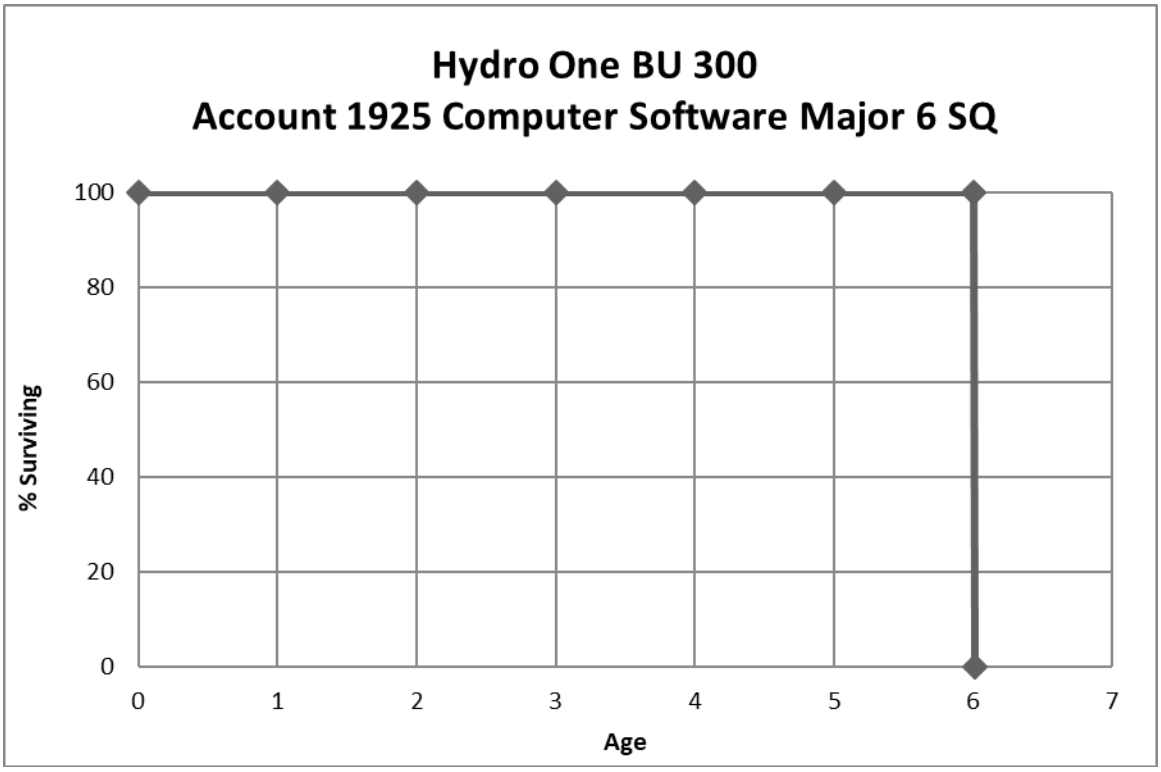
Account 1920 Computer Hardware - Minor (5 SQ)

This account consists of computer hardware, specifically computers, for general use. The plant balance in this account at December 31, 2024 is $101.6 million. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



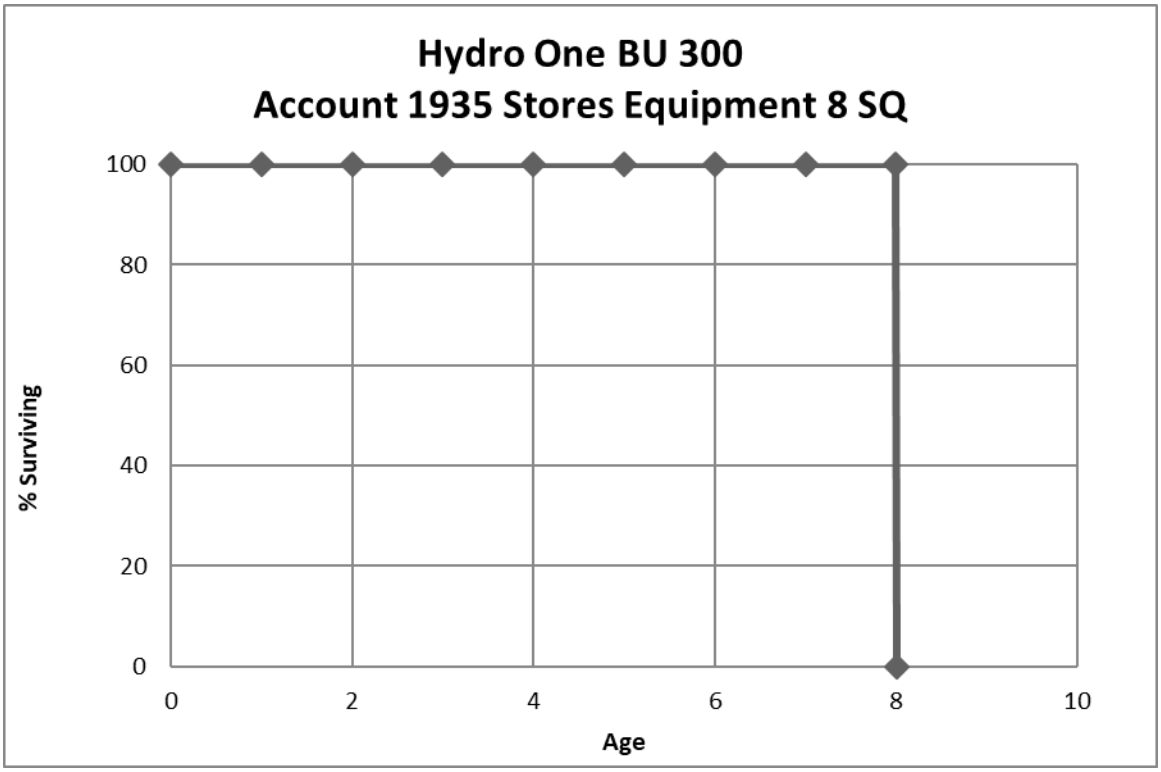
Account 1925 Computer Software (6 SQ)

This account consists of general computer software. Such assets include general system software and small amounts of associated hardware. The plant balance in this account at December 31, 2024 is $13.0 million. Currently, the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



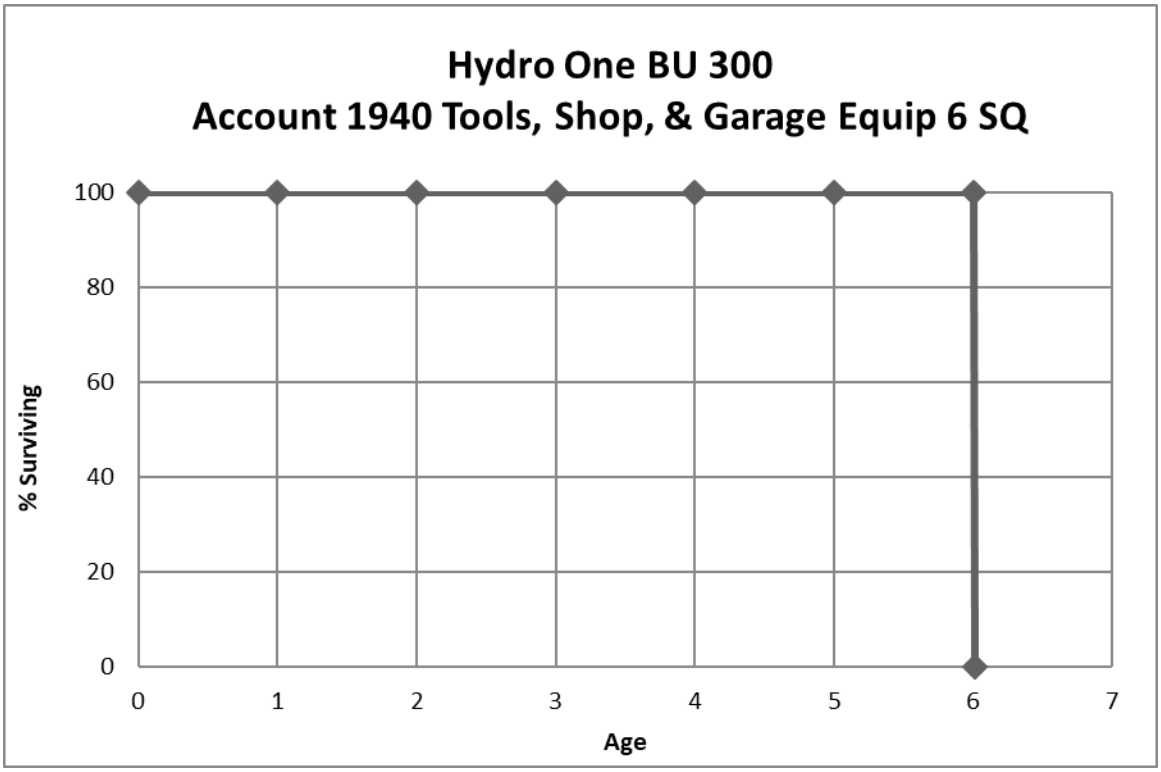
Account 1935 Stores Equipment (8 SQ)

This account consists of general stores equipment. Such assets include shelving and other stores assets. The plant balance in this account at December 31, 2024 is $0.4 million. Currently, the amortization life of this account is 8 years. After reviewing plant lives with Company personnel, the determination was that the existing 8-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



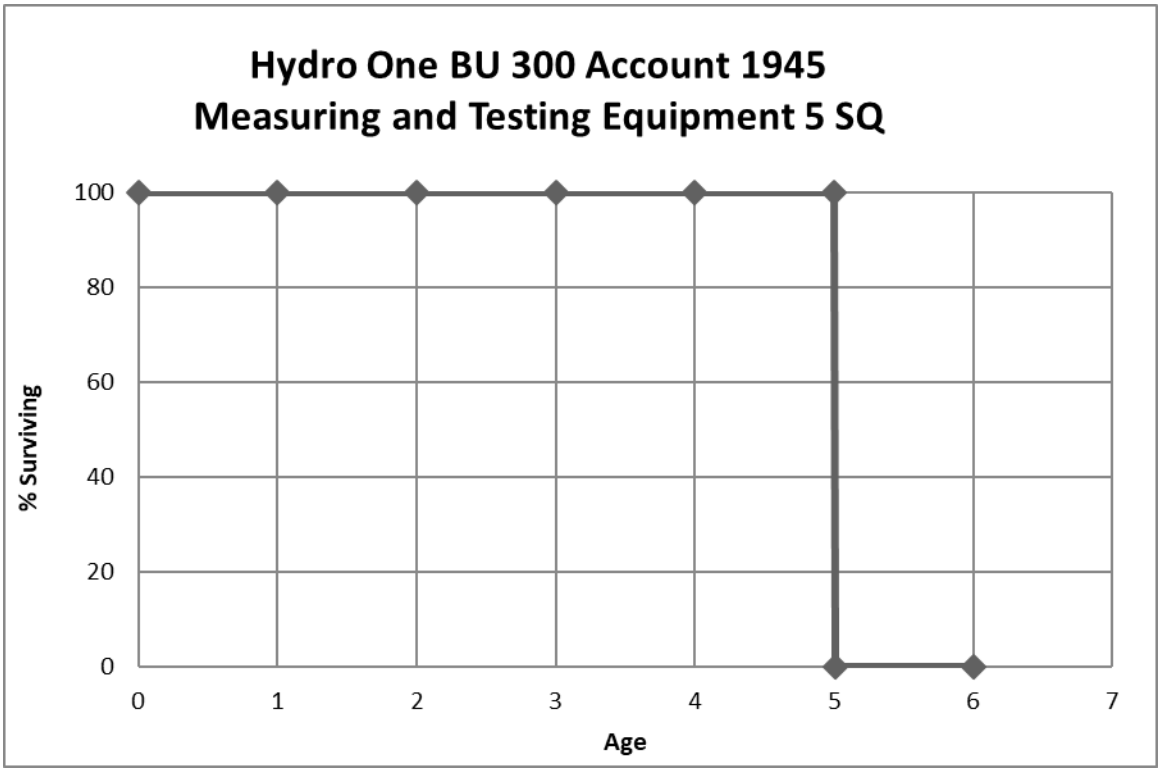
Account 1940 Tools Shop and Garage Equipment (6 SQ)

This account consists of general tools, shop, and garage equipment. The plant balance in this account at December 31, 2024 is $12.0 million. Currently, the amortization life of this account is 6 years. After reviewing plant lives with Company personnel, the determination was that the existing 6-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



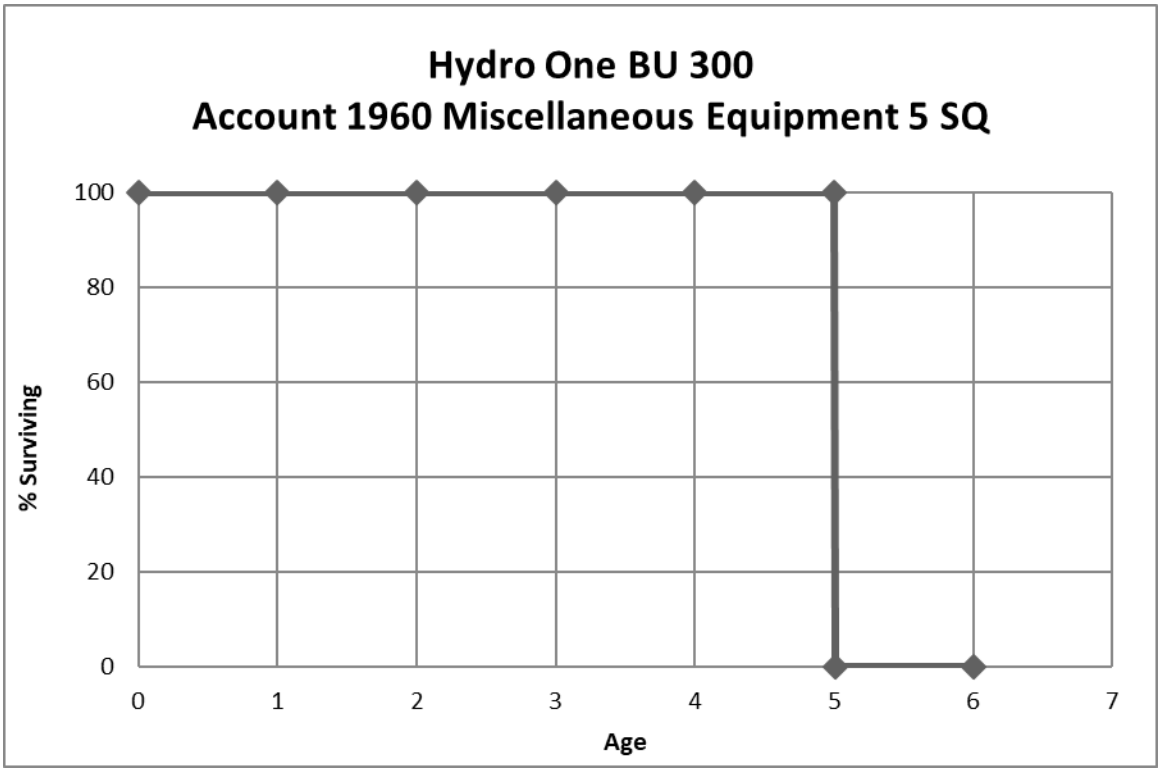
Account 1945 Measurement and Testing Equipment (5 SQ)

This account consists of general measuring and testing equipment. The plant balance in this account at December 31, 2024 is $11.8 million. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



Account 1960 Miscellaneous Equipment (5 SQ)

This account consists of general miscellaneous equipment. The plant balance in this account at December 31, 2024 is $9.0 million. Currently, the amortization life of this account is 5 years. After reviewing plant lives with Company personnel, the determination was that the existing 5-year life is still appropriate for this account. A representative graph showing the pattern of retirements for this account is shown below.



APPENDIX A

Depreciation Rate Calculations

HYDRO ONE
BU 210 TRANSMISSION PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Allocated Reserve 12/31/2024	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate	
INTANGIBLE PLANT								
1609	Capital Contributions	15,075,853.29	7,745,262.97	7,330,590.32	4.85	1,512,865.90	10.04%	
1610	Computer Software	98,399,413.07	22,920,942.39	75,478,470.68	7.66	9,849,822.77	10.01%	(1)
	Fully Accrued Plant							
TRANSMISSION PLANT								
1706	Land Rights	263,587,265.59	97,340,181.62	166,247,083.97	66.65	2,494,414.34	0.95%	
1708	Buildings and Fixtures	841,542,853.54	313,335,065.59	528,207,787.95	32.70	16,150,683.86	1.92%	
1715	Station Equipment	13,205,113,998.20	4,614,977,057.54	8,590,136,940.66	29.39	292,260,667.89	2.21%	
1720	Towers and Fixtures	3,435,163,379.32	1,022,303,121.32	2,412,860,258.00	53.38	45,202,100.99	1.32%	
1730	Overhead Conductors and Devices	2,603,948,251.54	702,921,580.58	1,901,026,670.96	62.76	30,288,161.27	1.16%	
1735	Undergound Conduit	312,694,127.30	118,524,663.99	194,169,463.31	52.61	3,690,487.37	1.18%	
1740	Underground Conductors and Devices	187,141,268.71	35,055,401.02	152,085,867.69	54.83	2,773,554.68	1.48%	
1745	Roads and Trails	542,438,534.86	147,618,503.85	394,820,031.01	48.19	8,192,496.24	1.51%	
General Plant								
	Depreciable							
1908	Buildings and Fixtures	208,848,963.97	133,717,614.14	75,131,349.83	32.33	2,323,753.93	1.11%	
1910	Leashold Improvements	123,253.22	110,159.89	13,093.33	1.06	12,325.32	10.00%	(2)
1922	Computer Hardware- Major	43,898,378.90	23,822,594.57	20,075,784.33	5.84	3,435,199.20	7.83%	
1955	Communication Equipment	664,792,864.80	472,193,788.44	192,599,076.36	12.47	15,443,910.91	2.32%	
1980	System Supervisory Equipment	454,252,852.06	439,982,412.84	14,270,439.22	0.76	14,270,439.22	9.09%	(2)
	Amortizable							
1925	Computer Software Major	8,563,318.68	5,494,794.39	3,068,524.29	2.15	1,427,219.78	16.67%	
	Total	22,885,584,577.05	8,158,063,145.13	14,727,521,431.92		449,328,103.68		

(1) Plant reduced for fully accrued assets.
(2) Account will fully accrue in 2025. Propose a whole life rate shown above for new additions 2025 and after.

HYDRO ONE
BU 220 DISTRIBUTION PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2019

Account	Description	Plant Balance Total at 12/31/2024	Allocated Reserve 12/31/2024	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate	
INTANGIBLE PLANT								
1609	Capital Contributions	75,462,021.59	59,210,869.90	16,251,151.69	1.88	8,627,637.79	11.43%	
1610	Computer Software	271,160,258.74	113,012,281.01	158,147,977.73	5.59	28,284,346.27	10.43%	(1)
	Fully Accrued Plant						0.00%	
DISTRIBUTION PLANT								
	Depreciable							
1805	Land							
1806	Land Rights	295,358,908.86	102,416,357.91	192,942,550.95	70.86	2,722,789.02	0.92%	
1808	Building and Fixtures	28,584,486.86	8,761,180.86	19,823,306.00	37.05	534,989.07	1.87%	
1815	Transformer Station Equipment > 50 kV	254,048,921.59	104,517,676.24	149,531,245.35	31.39	4,763,930.40	1.88%	
1820	Distribution Station Equipment < 50 kV	958,529,862.42	330,187,025.19	628,342,837.23	34.09	18,433,297.33	1.92%	
1825	Distributied Energy Resources	9,054,010.26	1,885,558.67	7,168,451.59	16.50	434,451.61	4.80%	
1830	Poles, Towers and Fixtures	5,864,826,220.31	1,259,010,435.85	4,605,815,784.46	49.18	93,658,720.34	1.60%	
1835	Overhead Conductors and Devices	2,223,710,156.58	842,284,819.60	1,381,425,336.98	39.54	34,938,017.29	1.57%	
1840	Underground Conduit	32,762,341.47	12,944,258.68	19,818,082.79	40.08	494,444.72	1.51%	
1845	Underground Conductors and Devices	984,144,262.11	632,287,567.37	351,856,694.74	15.00	23,460,492.25	2.38%	
1850	Line Transformers	2,167,135,549.18	957,003,520.75	1,210,132,028.43	24.06	50,289,178.54	2.32%	
1860	Meters	839,396,069.25	211,021,636.03	628,374,433.22	14.20	44,259,722.24	5.27%	
1860	Meters (Sustainment) (All transfer to 1860)			0.00				
1555	Smart Meters (1st Generation	295,181,274.07	270,653,505.83	24,527,768.24	2.98	8,220,579.23	2.78%	
GENERAL PLANT								
	Depreciable							
1908	Building and Fixtures	267,200,834.06	119,871,768.94	147,329,065.12	35.15	4,190,976.35	1.57%	
1910	Leasehold Improvements	17,955,946.84	16,274,298.48	1,681,648.36	3.49	481,955.43	2.68%	
1922	Minor Computer Equipment- Hardware	4,733,131.11	4,733,131.11	0.00	0.10	0.00	20.00%	(2)
1955	Communication Equipment	29,661,129.17	29,523,554.02	137,575.15	0.44	309,411.82	10.00%	
1980	System Supervisory Equipment	134,202,316.42	134,202,316.42	0.00	1.06	0.00	16.67%	(2)
1985	Sentinel Lighting Rental Units	15,407,748.95	14,390,870.26	1,016,878.69	10.14	100,281.14	0.65%	
	Amortized							
1925	Computer Application Software	2,405,503.17	1,095,462.13	1,310,041.04	3.27	400,917.20	16.67%	
		14,770,920,953.01	5,225,288,095.25			324,606,138.02		

(1) Plant reduced for fully accrued assets.
(2) Account will fully accrue in 2025. Propose a whole life rate shown above for new additions 2025 and after.

HYDRO ONE
BU 300 COMMON PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Allocated Reserve 12/31/2024	Unaccrued Balance	Remaining Life	Annual Accrual	Annual Accrual Rate	
INTANGIBLE PLANT								
1610	Computer Software	580,288,962.17	194,467,155.18	385,821,806.99	5.65	68,248,687.87	11.76%	
GENERAL PLANT								
	Depreciable							
1908	Building and Fixtures	309,639,993.00	19,091,985.83	290,548,007.17	40.26	7,217,642.44	2.33%	
1910	Leasehold Improvements	48,895,970.86	16,693,751.15	32,202,219.71	4.65	6,919,614.11	14.15%	
1922	Computer Equipment- Hardware	53,063,463.44	14,190,203.38	38,873,260.06	6.32	6,152,755.83	11.60%	
1955	Communication Equipment	22,440,009.39	22,440,009.39	0.00	0.08	0.00	14.29%	(1)
1980	System Supervisory Equipment	19,682,150.19	8,395,926.82	11,286,223.37	3.95	2,854,495.81	14.50%	
	Amortized							
1915	Office Furniture and Equipment	6,707,809.94	3,306,283.09	3,401,526.86	3.55	958,258.56	14.29%	
1920	Computer Hardware-Minor	101,641,294.12	60,492,172.58	41,149,121.54	2.02	20,328,258.82	20.00%	
1925	Computer Software Major	13,010,919.51	8,675,415.23	4,335,504.28	2.00	2,168,486.59	16.67%	
1935	Stores Equipment	357,652.50	44,654.53	312,997.97	7.00	44,706.56	12.50%	
1940	Tools, Shop and Garage Equipment	11,965,488.61	5,686,782.85	6,278,705.76	3.15	1,994,248.10	16.67%	
1945	Measuring and Testing Equipment	11,831,015.53	6,342,614.23	5,488,401.30	2.32	2,366,203.11	20.00%	
1960	Miscellaneous Equipment	8,993,043.16	4,005,465.65	4,987,577.51	2.77	1,798,608.63	20.00%	
		1,188,517,772.42	363,832,419.90	824,685,352.52		121,051,966.43		

(1) Account is fully accrued. Propose a whole life rate shown above for new additions 2025 and after.

APPENDIX B

Depreciation Expense Comparison

HYDRO ONE
BU 210 TRANSMISSION PLANT
COMPARISON OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Rate	Difference	
INTANGIBLE PLANT								
1609	Capital Contributions	15,075,853.29	10.00%	1,507,585.33	10.04%	1,512,865.90	5,280.57	
1610	Computer Software	98,399,413.07	10.00%	9,839,941.31	10.01%	9,849,822.77	9,881.46	(1)
	Fully Accrued							
TRANSMISSION PLANT								
1705	Land - Depreciable							
1706	Land Rights	263,587,265.59	0.92%	2,412,691.58	0.95%	2,494,414.34	81,722.77	
1708	Buildings and Fixtures	841,542,853.54	1.81%	15,244,181.27	1.92%	16,150,683.86	906,502.60	
1715	Station Equipment	13,205,113,998.20	1.93%	254,300,867.05	2.21%	292,260,667.89	37,959,800.84	
1720	Towers and Fixtures	3,435,163,379.32	1.24%	42,533,437.30	1.32%	45,202,100.99	2,668,663.70	
1730	Overhead Conductors and Devices	2,603,948,251.54	1.30%	33,935,997.45	1.16%	30,288,161.27	(3,647,836.19)	
1735	Undergound Conduit	312,694,127.30	1.46%	4,567,874.54	1.18%	3,690,487.37	(877,387.17)	
1740	Underground Conductors and Devices	187,141,268.71	1.75%	3,279,193.35	1.48%	2,773,554.68	(505,638.67)	
1745	Roads and Trails	542,438,534.86	1.50%	8,141,161.16	1.51%	8,192,496.24	51,335.07	
General Plant								
	Depreciable							
1905	Land - Depreciable							
1908	Buildings and Fixtures	208,848,963.97	1.81%	3,780,166.25	1.11%	2,323,753.93	(1,456,412.32)	
1910	Leashold Improvements	123,253.22	10.00%	12,325.32	10.00% (2)	12,325.32	0.00	(2)
1922	Computer Hardware- Major	43,898,378.90	7.92%	3,476,751.61	7.83%	3,435,199.20	(41,552.41)	
1955	Communication Equipment	664,792,864.80	4.10%	27,256,507.46	2.32%	15,443,910.91	(11,812,596.54)	
1980	System Supervisory Equipment	454,252,852.06	7.62%	14,270,439.22	9.09%	14,270,439.22	0.00	(2)
	Amortizable							
1925	Computer Software Major	8,563,318.68	16.67%	1,427,219.78	16.67%	1,427,219.78	0.00	
		22,885,584,577.05		425,986,339.96		449,328,103.68	23,341,763.72	

(1) Plant reduced for fully accrued assets.
(2) Account will fully accrue in 2025. Propose a whole life rate shown above for new additions 2025 and after.

HYDRO ONE
BU 220 DISTRIBUTION PLANT
COMPARISON OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Amount	Difference	
INTANGIBLE PLANT								
1609	Capital Contributions	75,462,021.59	10.00%	7,546,202.16	11.43%	8,627,637.79	1,081,435.63	
1610	Computer Software	271,160,258.74	10.00%	27,116,025.87	10.43%	28,284,346.27	1,168,320.39	(1)
DISTRIBUTION PLANT								
Depreciable								
1805	Land							
1806	Land Rights	295,358,908.86	0.91%	2,687,766.07	0.92%	2,722,789.02	35,022.95	
1808	Building and Fixtures	28,584,486.86	1.93%	551,680.60	1.87%	534,989.07	(16,691.53)	
1815	Transformer Station Equipment > 50 kV	254,048,921.59	1.91%	4,852,334.40	1.88%	4,763,930.40	(88,404.00)	
1820	Distribution Station Equipment < 50 kV	958,529,862.42	2.06%	19,745,715.17	1.92%	18,433,297.33	(1,312,417.84)	
1825	Distributied Energy Resources	9,054,010.26	0.00%	0.00	4.80%	434,451.61	434,451.61	
1830	Poles, Towers and Fixtures	5,864,826,220.31	1.71%	100,288,528.37	1.60%	93,658,720.34	(6,629,808.03)	
1835	Overhead Conductors and Devices	2,223,710,156.58	1.59%	35,356,991.49	1.57%	34,938,017.29	(418,974.20)	
1840	Underground Conduit	32,762,341.47	1.49%	488,158.89	1.51%	494,444.72	6,285.83	
1845	Underground Conductors and Devices	984,144,262.11	2.52%	24,800,435.41	2.38%	23,460,492.25	(1,339,943.15)	
1850	Line Transformers	2,167,135,549.18	2.26%	48,977,263.41	2.32%	50,289,178.54	1,311,915.12	
1860	Meters	839,396,069.25	5.38%	45,159,508.53	5.27%	44,259,722.24	(899,786.29)	
1860	Meters (Sustainment) (All transfer to 1860)	0.00	5.38%	0.00	0.00%	0.00	0.00	
1555	Smart Meters (1st Generation	295,181,274.07	4.32%	12,751,831.04	2.78%	8,220,579.23	(4,531,251.81)	
GENERAL PLANT								
Depreciable								
1908	Building and Fixtures	267,200,834.06	1.74%	4,649,294.51	1.57%	4,190,976.35	(458,318.17)	
1910	Leasehold Improvements	17,955,946.84	5.60%	1,005,533.02	2.68%	481,955.43	(523,577.60)	
1922	Minor Computer Equipment- Hardware	4,733,131.11	14.29%	0.00	20.00%	0.00	0.00	(2)
1955	Communication Equipment	29,661,129.17	16.67%	4,944,510.23	10.00%	309,411.82	(4,635,098.42)	
1980	System Supervisory Equipment	134,202,316.42	9.99%	0.00	16.67%	0.00	0.00	
1985	Sentinel Lighting Rental Units	15,407,748.95	2.32%	357,459.78	0.65%	100,281.14	(257,178.64)	
Amortized								
1925	Computer Application Software	2,405,503.17	16.67%	400,917.20	16.67%	400,917.20	0.00	
	Total	14,770,920,953.01		341,680,156.13		324,606,138.02	(17,074,018.12)	

(1) Plant reduced for fully accrued assets.
(2) Account will fully accrue in 2025. Propose a whole life rate shown above for new additions 2025 and after.

HYDRO ONE
BU 300 COMMON PLANT
CALCULATION OF DEPRECIATION RATES
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Current Accrual Rate	Current Accrual Amount	Proposed Accrual Rate	Proposed Accrual Rate	Difference
INTANGIBLE PLANT							
1610	Computer Software	580,288,962.17	8.33%	48,338,070.55	11.76%	68,248,687.87	19,910,617.32
GENERAL PLANT							
	Depreciable						
1908	Building and Fixtures	309,639,993.00	1.60%	4,964,195.76	2.33%	7,217,642.44	2,253,446.68
1910	Leasehold Improvements	48,895,970.86	3.99%	1,951,378.00	14.15%	6,919,614.11	4,968,236.11
1922	Computer Equipment- Hardware	53,063,463.44	4.28%	2,273,233.85	11.60%	6,152,755.83	3,879,521.97
1955	Communication Equipment	22,440,009.39	0.97%	0.00	14.29%	0.00	0.00 (1)
1980	System Supervisory Equipment	19,682,150.19	11.01%	2,166,831.85	14.50%	2,854,495.81	687,663.96
	Amortized						
1915	Office Furniture and Equipment	6,707,809.94	14.29%	958,258.56	14.29%	958,258.56	0.00
1920	Computer Hardware-Minor	101,641,294.12	20.00%	20,328,258.82	20.00%	20,328,258.82	0.00
1925	Computer Software Major	13,010,919.51	16.67%	2,168,486.59	16.67%	2,168,486.59	0.00
1935	Stores Equipment	357,652.50	12.50%	44,706.56	12.50%	44,706.56	0.00
1940	Tools, Shop and Garage Equipment	11,965,488.61	16.67%	1,994,248.10	16.67%	1,994,248.10	0.00
1945	Measuring and Testing Equipment	11,831,015.53	20.00%	2,366,203.11	20.00%	2,366,203.11	0.00
1960	Miscellaneous Equipment	8,993,043.16	20.00%	1,798,608.63	20.00%	1,798,608.63	0.00
	Total	1,188,517,772.42	7.52%	89,352,480.39	10.19%	121,051,966.43	31,699,486.04

(1) Account is fully accrued. Propose a whole life rate shown above for new additions 2025 and after.

APPENDIX C

Depreciation Parameter Comparison

HYDRO ONE
CURRENT AT PROPOSED DEPRECIATION PARAMETERS
BU 210 TRANSMISSION AT DECEMBER 31, 2024

		Current				Proposed		
USofA	**USofA Description**	**Life**	**Curve**	**Rate**	**Procedure**	**Curve**	**Life**	**Procedure**
INTANGIBLE PLANT								
1609	Capital Contributions	10	SQ	10.00%	Amortize	10	SQ	Amortize
1610	Computer Software	10	SQ	10.00%	Amortize	10	SQ	Amortize
TRANSMISSION PLANT								
1705	Land - Depreciable	NA	NA	0.00%	SL BG RL	NA	NA	SL BG RL
1706	Land Rights	100	R4	0.92%	SL BG RL	100	R4	SL BG RL
1708	Buildings and Fixtures	50	S6	1.81%	SL BG RL	50	S6	SL BG RL
1715	Station Equipment	48	R2.5	1.93%	SL BG RL	43	R2.5	SL BG RL
1720	Towers and Fixtures	75	R3	1.24%	SL BG RL	73	R3	SL BG RL
1730	Overhead Conductors and Devices	70	R4	1.30%	SL BG RL	83	R4	SL BG RL
1735	Undergound Conduit	60	R2	1.46%	SL BG RL	80	R2	SL BG RL
1740	Underground Conductors and Devices	55	R2	1.75%	SL BG RL	66	R2	SL BG RL
1745	Roads and Trails	60	R4	1.50%	SL BG RL	64	R4	SL BG RL
General Plant								
	Depreciable							
1905	Land - Depreciable	NA	NA	0.00%		NA	NA	
1908	Buildings and Fixtures	50	S4	1.81%	SL BG RL	50	S4	SL BG RL
1910	Leashold Improvements	10	S6	10.00%	SL BG RL	10	S6	SL BG RL
1922	Computer Hardware- Major	10	S6	7.92%	SL BG RL	7	S6	SL BG RL
1925								
1955	Communication Equipment	20	R2.5	4.10%	SL BG RL	24	R2.5	SL BG RL
1980	System Supervisory Equipment	10	R4	7.62%	SL BG RL	11	R4	SL BG RL
	Amortizable							
1925	Computer Software Major	6	SQ	16.67%	Amortize	6	SQ	Amortize

BU 220 Current vs Proposed Parameters

USofA	Description	Current Curve Li	Current Accrual Rate	Current System	Proposed Curve	Proposed Life	Proposed System
INTANGIBLE PLANT							
1609	Capital Contributions	10 SQ	10.00%	Amortizatior	10	SQ	Amortization
1610	Computer Software	10 SQ	10.00%	Amortizatior	10	SQ	Amortization
DISTRIBUTION PLANT							
Depreciable							
1805	Land	NA	0.00%		NA	NA	
1806	Land Rights	100 R4	0.91%	SL- BG-RL	100	R4	SL- BG-RL
1808	Building and Fixtures	50 R4	1.93%	SL- BG-RL	50	R4	SL- BG-RL
1815	Transformer Station Equipment > 50 kV	48 R2.5	1.91%	SL- BG-RL	48	R2.5	SL- BG-RL
1820	Distribution Station Equipment < 50 kV	45 R2.5	2.06%	SL- BG-RL	48	R2.5	SL- BG-RL
1825	Distributied Energy Resources				20	SQ	
1830	Poles, Towers and Fixtures	55 R2	1.71%	SL- BG-RL	60	R2	SL- BG-RL
1835	Overhead Conductors and Devices	55 R2	1.59%	SL- BG-RL	58	R2	SL- BG-RL
1840	Underground Conduit	60 R1	1.49%	SL- BG-RL	60	R1	SL- BG-RL
1845	Underground Conductors and Devices	33 R3	2.52%	SL- BG-RL	33	R3	SL- BG-RL
1850	Line Transformers	40 R2	2.26%	SL- BG-RL	40	R2	SL- BG-RL
1860	Meters	18 R3	5.38%	SL- BG-RL	18	R3	SL- BG-RL
1860	Meters (Sustainment) (All transfer to 1860)	18 R3	5.38%	SL- BG-RL	13	S1.5	SL- BG-RL
1555	Smart Meters (1st Generation	18 R3	4.32%	SL- BG-RL	13	S1.5	SL- BG-RL
*							
GENERAL PLANT							
1908	Building and Fixtures	50 S4	1.74%	SL- BG-RL	48	S4	SL- BG-RL
1910	Leasehold Improvements	10 S6	5.60%	SL- BG-RL	10	S6	SL- BG-RL
1922	Minor Computer Equipment- Hardware	10 S6	14.29%	SL- BG-RL	10	S6	SL- BG-RL
1955	Communication Equipment	7 S6	16.67%	SL- BG-RL	10	S6	SL- BG-RL
1980	System Supervisory Equipment	6 L2	9.99%	SL- BG-RL	6	L2	SL- BG-RL
1985	Sentinel Lighting Rental Units	27 R3	2.32%	SL- BG-RL	30	R3	SL- BG-RL
Amortized							
1925	Computer Application Software	6 SQ	16.67%	Amortizatior	6	SQ	Amortization

BU 300 Current vs Proposed Parameters

USofA		Current			Proposed	
		Curve Life	Rate	System	Curve Life	System
INTANGIBLE PLANT						
1610	Computer Software	12 SQ	8.33%	Amortization	10 SQ	Amortization
GENERAL PLANT						
Depreciable						
1908	Building and Fixtures	50 S4	1.60%	SL-BG-RL	50 S4	SL-BG-RL
1910	Leasehold Improvements	10 S6	3.99%	SL-BG-RL	15 S6	SL-BG-RL
1922	Computer Equipment- Hardware	10 S6	4.28%	SL-BG-RL	10 S6	SL-BG-RL
1955	Communication Equipment	7 S6	0.97%	SL-BG-RL	7 S6	SL-BG-RL
1980	System Supervisory Equipment	7 S6	11.01%	SL-BG-RL	12 S6	SL-BG-RL
Amortized						
1915	Office Furniture and Equipment	7 SQ	14.28%	Amortization	7 SQ	Amortization
1920	Computer Hardware-Minor	5 SQ	20.00%	Amortization	5 SQ	Amortization
1925	Computer Software Major	6 SQ	16.66%	Amortization	6 SQ	Amortization
1935	Stores Equipment	8 SQ	12.50%	Amortization	8 SQ	Amortization
1940	Tools, Shop and Garage Equipment	6 SQ	16.66%	Amortization	6 SQ	Amortization
1945	Measuring and Testing Equipment	5 SQ	20.00%	Amortization	5 SQ	Amortization
1960	Miscellaneous Equipment	5 SQ	20.00%	Amortization	5 SQ	Amortization

APPENDIX D

Summary of Depreciation Book Reserve, Reallocated Depreciation Reserve, and Theoretical Depreciation Reserve

HYDRO ONE
BU 210 TRANSMISSION PLANT
COMPARISON OF PLANT AND ACCUMULATED DEPRECIATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Book Reserve	Suspence Adjustment Plant	Suspence Adjustment Reserve	Fully Accrued Plant	Fully Accrued Reserve	Adjusted Plant	Adjusted Reserve	Allocated Reserve	Theoretical Reserve	Book - Allocated Reserve Difference
INTANGIBLE PLANT												
1609	Capital Contributions	15,075,853.29	7,694,219.47					15,075,853.29	7,694,219.47	7,745,262.97	7,770,849.98	(51,043.50)
1610	Computer Software	97,731,988.58	24,547,274.73	2,321,624.03	78,910.70	(1,654,199.54)	(1,654,199.54)	98,399,413.07	22,971,985.89	22,920,942.39	22,996,663.31	51,043.50
Total Intangible		112,807,841.87	32,241,494.20	2,321,624.03	78,910.70	(1,654,199.54)	(1,654,199.54)	113,475,266.36	30,666,205.36	30,666,205.36	30,767,513.29	0.00
TRANSMISSION PLANT												
1705	Land - Depreciable				0.00			0.00	0.00	0.00	3,693,760.97	0.00
1706	Land Rights	263,587,265.59	103,434,871.62		(52,530.58)			263,587,265.59	103,382,341.04	97,340,181.62	87,912,304.49	6,042,159.42
1708	Buildings and Fixtures	841,542,853.54	324,608,677.92		(6.02)			841,542,853.54	324,608,671.90	313,335,065.59	291,577,305.87	11,273,606.31
1715	Station Equipment	13,206,843,996.61	4,486,867,562.10	(1,729,998.41)	(13,535,735.09)			13,205,113,998.20	4,473,331,827.01	4,614,977,057.54	4,178,945,968.63	(141,645,230.53)
1720	Towers and Fixtures	3,435,163,379.32	997,833,129.46		(7,509,394.94)			3,435,163,379.32	990,323,734.52	1,022,303,121.32	923,288,017.20	(31,979,386.80)
1730	Overhead Conductors and Devices	2,606,778,615.42	790,368,858.08	(2,830,363.88)	(5,160,613.76)			2,603,948,251.54	785,208,244.32	702,921,580.58	634,840,155.38	82,286,663.74
1735	Undergound Conduit	312,694,127.30	166,657,674.73					312,694,127.30	166,657,674.73	118,524,663.99	107,044,965.16	48,133,010.74
1740	Underground Conductors and Devices	187,141,268.71	44,592,831.66					187,141,268.71	44,592,831.66	35,055,401.02	31,660,112.38	9,537,430.64
1745	Roads and Trails	542,438,534.86	163,976,386.11		(6,135.79)			542,438,534.86	163,970,250.32	147,618,503.85	133,974,815.10	16,351,746.47
Total Transmission		21,396,190,041.35	7,078,339,991.68	(4,560,362.29)	(26,264,416.18)			21,391,629,679.06	7,052,075,575.50	7,052,075,575.50	6,389,243,644.20	(0.00)
General Plant												
	Depreciable							0.00	0.00			
1908	Buildings and Fixtures	208,848,963.97	81,722,094.98					208,848,963.97	81,722,094.98	133,717,614.14	73,799,341.33	(51,995,519.16)
1910	Leashold Improvements	123,253.22	84,459.33		(568.25)			123,253.22	83,891.08	110,159.89	110,159.89	(26,268.81)
1922	Computer Hardware- Major	43,898,378.90	19,795,137.17					43,898,378.90	19,795,137.17	23,822,594.57	18,243,552.62	(4,027,457.40)
1955	Communication Equipment	664,792,864.80	427,678,707.88		(633,357.03)			664,792,864.80	427,045,350.85	472,193,788.44	319,353,345.94	(45,148,437.59)
1980	System Supervisory Equipment	454,252,852.06	541,191,629.56					454,252,852.06	541,191,629.56	439,982,412.84	423,058,490.63	101,209,216.72
Total General		1,371,916,312.95	1,070,472,028.92	0.00	(633,925.28)			1,371,916,312.95	1,069,838,103.64	1,069,826,569.88	834,564,890.41	11,533.76
	Amortizable											
1925	Computer Software Major	13,719,682.74	10,639,624.69	0.00		(5,156,364.06)	(5,156,364.06)	8,563,318.68	5,483,260.63	5,494,794.39	5,494,794.39	(11,533.76)
Total Amortizable		13,719,682.74	10,639,624.69	0.00	0.00	(5,156,364.06)	(5,156,364.06)	8,563,318.68	5,483,260.63	5,494,794.39	5,494,794.39	(11,533.76)
Total Depreciable		22,894,633,878.91	8,191,693,139.49	(2,238,738.26)	(26,819,430.76)	(6,810,563.60)	(6,810,563.60)	22,885,584,577.05	8,158,063,145.13	8,158,063,145.13	7,260,070,842.29	(0.00)
Non-Depreciable												
1705N	Land - Non Depreciable	285,669,456.73	0.00									
1706N	Land Rights	286,208.41	0.00									
1708N	Buildings and Fixtures	1,816,289.83	1,816,289.83									
1715N	Station Equipment	35,802,237.74	35,802,237.74									
1720N	Towers and Fixtures	0.00	0.00									
1721N		47,673.00	0.00									
1730N	Overhead Conductors and Devices	0.00	0.00									
1905N	Land - Non Depreciable	17,033,878.52	0.00									
2040N		73,981,052.56	0.00									
		23,309,270,675.70	8,229,311,667.06	(2,238,738.26)	(26,819,430.76)							

HYDRO ONE
BU 220 DISTRIBUTION PLANT
COMPARISON OF PLANT AND ACCUMULATED DEPRECIATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Per Book Plant Balance Total at 12/31/2024	Per Book Book Reserve	Suspense Plant	Suspense Reserve	Suspense Plant	Suspense Reserve	Adjusted Plant	Adjusted Reserve	Allocated Reserve	Theoretical Reserve	Book - Allocated Reserve Difference
INTANGIBLE PLANT												
1609	Capital Contributions	76,850,690.25	52,684,385.87			(1,388,668.66)	(1,388,668.66)	75,462,021.59	51,295,717.21	59,210,869.90	60,986,306.97	(7,915,152.69)
1610	Computer Software	427,845,161.89	269,599,990.34	(6,078,207.85)	1,934,138.66	(150,606,695.30)	(150,606,695.30)	271,160,258.74	120,927,433.70	113,012,281.01	119,544,781.57	7,915,152.69
DISTRIBUTION PLANT												
Depreciable												
1805	Land				(1,523.28)			0.00	(1,523.28)			(1,523.28)
1806	Land Rights	295,358,908.86	100,627,478.73					295,358,908.86	100,627,478.73	102,416,357.91	86,061,380.41	(1,788,879.18)
1808	Building and Fixtures	28,584,486.86	7,892,868.41					28,584,486.86	7,892,868.41	8,761,180.86	7,401,286.60	(868,312.45)
1815	Transformer Station Equipment > 50 kV	254,048,921.59	105,421,097.11					254,048,921.59	105,421,097.11	104,517,676.24	87,920,989.00	903,420.87
1820	Distribution Station Equipment < 50 kV	957,801,268.31	360,447,403.70	728,594.11	148,087.94			958,529,862.42	360,595,491.64	330,187,025.19	277,826,257.41	30,408,466.45
1825	Distributied Energy Resources	9,054,010.26	729,597.86					9,054,010.26	729,597.86	1,885,558.67	1,584,451.80	(1,155,960.81)
1830	Poles, Towers and Fixtures	5,866,863,215.38	1,169,219,874.32	(2,036,995.07)	(3,283,229.48)			5,864,826,220.31	1,165,936,644.84	1,259,010,435.85	1,057,957,715.58	(93,073,791.00)
1835	Overhead Conductors and Devices	2,223,710,156.58	850,483,696.49		209,257.86			2,223,710,156.58	850,692,954.35	842,284,819.60	707,779,457.77	8,408,134.75
1840	Underground Conduit	32,678,023.44	13,413,500.92	84,318.03	63,735.14			32,762,341.47	13,477,236.06	12,944,258.68	10,876,281.78	532,977.38
1845	Underground Conductors and Devices	984,140,744.73	640,666,155.18	3,517.38	1,018.23			984,144,262.11	640,667,173.41	632,287,567.37	536,870,396.12	8,379,606.04
1850	Line Transformers	2,166,728,014.60	1,037,698,551.19	407,534.58	2,664,762.87			2,167,135,549.18	1,040,363,314.06	957,003,520.75	863,415,636.49	83,359,793.31
1860	Meters	842,399,749.18	192,146,112.19	(3,003,679.93)	(2,741,889.08)			839,396,069.25	189,404,223.11	211,021,636.03	177,325,552.32	(21,617,412.92)
1555	Smart Meters (1st Generation	295,181,274.07	257,913,176.50					295,181,274.07	257,913,176.50	270,653,505.83	227,432,558.61	(12,740,329.33)
1565	Smart Meters		(746,189.82)					0.00	(746,189.82)	0.00	0.00	(746,189.82)
											0.00	
GENERAL PLANT												
Depreciable												
1908	Building and Fixtures	267,200,834.06	80,223,664.68		(93,979.99)			267,200,834.06	80,129,684.69	119,871,768.94	71,510,310.36	(39,742,084.25)
1910	Leasehold Improvements	17,955,946.84	11,459,357.07					17,955,946.84	11,459,357.07	16,274,298.48	11,690,722.54	(4,814,941.41)
1922	Minor Computer Equipment- Hardware	4,733,131.11	5,382,331.29		1,523.28			4,733,131.11	5,383,854.57	4,733,131.11	4,685,540.41	650,723.46
1955	Communication Equipment	29,661,129.17	28,396,548.12		(85,401.44)			29,661,129.17	28,311,146.68	29,523,554.02	28,342,293.26	(1,212,407.34)
1980	System Supervisory Equipment	134,202,316.42	191,237,055.04		(11,031,098.39)			134,202,316.42	180,205,956.65	134,202,316.42	110,565,432.68	46,003,640.23
1985	Sentinel Lighting Rental Units	15,407,748.95	13,543,532.83					15,407,748.95	13,543,532.83	14,390,870.26	10,199,786.50	(847,337.43)
			0.00							0.00	0.00	0.00
1925	Computer Application Software	2,405,503.17	1,057,868.87					2,405,503.17	1,057,868.87	1,095,462.13	1,095,462.13	(37,593.26)
		14,932,811,235.72	5,389,498,056.89	(9,894,918.75)	(12,214,597.68)	(151,995,363.96)	(151,995,363.96)	14,770,920,953.01	5,225,288,095.25	5,225,288,095.25	4,461,072,600.31	(0.00)

1805N	Land	60,074,913.45	43,082,943.68					60,074,913.45	43,082,943.68			
1815N	Transformer Station Equipment > 50 kV Fully Accrued	579,682.71	579,682.71					579,682.71	579,682.71			
1820N	Transformer Station Equipment < 50 kV Fully Accrued	358,321.70	358,321.70					358,321.70	358,321.70			
1830N	Poles, Towers, and Fixtures - Fully Accrued	7,856,671.86	6,861,613.86					7,856,671.86	6,861,613.86			
1835N	Overhead Conductors and Devices - Fully Accrued	6,349,048.91	6,349,048.91					6,349,048.91	6,349,048.91			
1845N	Underground Conductors and Devices - Fully Accrued	156,408.38	156,408.38					156,408.38	156,408.38			
1850N	Line Transformers - Fully Accrued	242,592.23	242,592.23					242,592.23	242,592.23			
1905N		13,057,345.87	-					13,057,345.87	0.00			
1908N		62,402.23	62,402.23					62,402.23	62,402.23			
1955N		220,900.84	220,900.84					220,900.84	220,900.84			
1980N		24,644.16	24,644.16					24,644.16	24,644.16			
2040N		1,318,765.41	-					1,318,765.41	0.00			

HYDRO ONE
BU 300 COMMON PLANT
COMPARISON OF PLANT AND ACCUMULATED DEPRECIATION
USING SL- BROAD GROUP REMAINING LIFE RATES
DEPRECIATION STUDY AS OF DECEMBER 31, 2024

Account	Description	Plant Balance Total at 12/31/2024	Book Reserve	Suspense Plant	Suspense Reserve	Fully Accrued Plant Plant	Fully Accrued Plant Reserve	Post Adjustment Plant	Post Adjustment Reserve	Allocated Reserve	Theoretical Reserve	Book - Allocated Reserve Difference
INTANGIBLE PLANT												
1610	Computer Software	973,804,155.16	606,915,007.27	(14,946,961.61)	(33,879,620.71)	(378,568,231.38)	(378,568,231.38)	580,288,962.17	194,467,155.18	194,467,155.18	252,241,430.48	0.00
GENERAL PLANT												
	Depreciable											
1908	Building and Fixtures	309,639,993.00	74,561,913.30					309,639,993.00	74,561,913.30	19,091,985.83	60,347,281.03	55,469,927.47
1910	Leasehold Improvements	48,895,970.86	49,949,957.10		(12,080,805.15)			48,895,970.86	37,869,151.95	16,693,751.15	33,725,965.02	21,175,400.80
1922	Computer Equipment- Hardware	53,063,463.44	20,910,126.65		(1,950,022.21)			53,063,463.44	18,960,104.44	14,190,203.38	19,537,838.96	4,769,901.06
1955	Communication Equipment	22,440,009.39	(5,800,002.98)		(24,592,067.17)			22,440,009.39	(30,392,070.15)	22,440,009.39	22,181,787.32	(52,832,079.54)
1980	System Supervisory Equipment	19,682,150.19	(6,385,833.95)		(7,058,873.82)			19,682,150.19	(13,444,707.77)	8,395,926.82	13,197,142.04	(21,840,634.59)
	Amortized											
1915	Office Furniture and Equipment	6,656,346.14	3,161,629.80	51,463.80	48,030.39			6,707,809.94	3,209,660.19	3,306,283.09	3,306,283.09	(96,622.90)
1920	Computer Hardware-Minor	105,523,881.10	58,257,661.55	31,873.57	(470,776.40)	(3,914,460.55)	(3,914,460.55)	101,641,294.12	53,872,424.60	60,492,172.58	60,492,172.58	(6,619,747.98)
1925	Computer Software Major	13,755,540.91	9,421,559.43			(744,621.40)	(744,621.40)	13,010,919.51	8,676,938.03	8,675,415.23	8,675,415.23	1,522.80
1935	Stores Equipment	357,652.50	43,879.14				0.00	357,652.50	43,879.14	44,654.53	44,654.53	(775.39)
1940	Tools, Shop and Garage Equipment	12,002,871.22	5,749,967.00	36,968.11	16,683.61	(74,350.72)	(74,350.72)	11,965,488.61	5,692,299.89	5,686,782.85	5,686,782.85	5,517.04
1945	Measuring and Testing Equipment	14,173,858.70	8,663,031.81			(2,342,843.17)	(2,342,843.17)	11,831,015.53	6,320,188.64	6,342,614.23	6,342,614.23	(22,425.59)
1960	Miscellaneous Equipment	8,993,043.16	3,995,482.46					8,993,043.16	3,995,482.46	4,005,465.65	4,005,465.65	(9,983.19)
	Total	1,588,988,935.77	829,444,378.58	(14,826,656.13)	(79,967,451.46)	(385,644,507.22)	(385,644,507.22)	1,188,517,772.42	363,832,419.90	363,832,419.90	489,784,833.00	(0.00)

Allocation methodology assumes that for intangible plant and amortized plant the reallocated reserve equals the theoretical reserve.
Any excess or deficiency is allocated across the depreciable plant accounts.

APPENDIX E

Summary of Projection Lives by Business Unit

Hydro One 2024 Tx BU 210

Description	Current P-Life UsoA	Current P-Life Category	Recommended P-Life UsoA	Recommended P-Life Category	Plant UsoA	Plant Category	$ x PL
INTANGIBLE PLANT							
1609 Contributed Capital							
Contribued Capital		10		10		15,075,853.29	150,758,532.90
Total USoA 1609	10 SQ	10	10 SQ	10		15,075,853.29	150,758,532.90
1610 Computer Software							
1656 Genrl- Adm & Serv- Lan Fib Opt		10		10		94,264,888.94	942,648,889.40
1657 Genrl - Adm & Serv-Sys Software		10		10		1,898,030.51	18,980,305.10
Unknown		10		10		3,890,693.16	38,906,931.60
Total USoA 1610	10 SQ	10	10 SQ	10		100,053,612.61	1,000,536,126.10
TRANSMISSION PLANT							
1705D Land - Depreciable							
1210 Land Purch & Acqui (old Cap)		100		100			
Total USoA 1705D		100		100			
1706 Land Rights							
1111 Rights & Easmnts <Landscaping>		100		100		2,959,748.65	295,974,865.00
1212 Easmnts & Rights		100		100		232,443,014.54	23,244,301,454.00
Land right		100		100		28,184,502.40	2,818,450,240.00
Total USoA 1706	100 R4	100	100 R4	100		263,587,265.59	26,358,726,559.00
1708 Buildings and Fixtures							
1120 Stn Building Components		50		50		470,385,095.69	23,519,254,784.50
1121 Cranes & Hoists In Bldgs		50		50		4,871,938.86	243,596,943.00
1260 Bldg W U/G Cable		50		50		31,732,351.46	1,586,617,573.00
1270 Serv Structures		50		50		25,538,800.67	1,276,940,033.50
Buildings & Fixtures		50		50		309,014,666.86	15,450,733,343.00
Total USoA 1708	50 S6	50	50 S6	50		841,542,853.54	42,077,142,677.00
1715 Station Equipment							
1111 Rights & Easmnts <Landscaping>		50		50		311.95	15,597.50
1112 Landscaping		50		50		30,241,537.68	1,512,076,884.00
1113 Site Imprv-Excl Fence		50		50		369,141,837.97	18,457,091,898.50
1123 Cost Equip Foundations		65		65		673,524,125.25	43,779,068,141.25
1127 Steel/Pipe Struc For Switch Eq		65		65		465,703,489.46	30,270,726,814.90
1128 Fences		30		30		141,264,473.82	4,237,934,214.60
1150 Rot Elec Eqp (No Wind'G)		65		65		18,827,430.13	1,223,782,958.45
1151 Rot Elec Eqp(Wind'Gs)		65		65		301,966.17	19,627,801.05
1152 Capacitors		30		30		149,734,781.28	4,492,043,438.40
1155 Regulators Incl Instal Cost		40		40		10,879,273.21	435,170,928.40
1159 Mobile Sub-Stations		30		30		3,463,397.31	103,901,919.30
1160 Misc Stn Eqp-Trsf/Volt Trsf		40		35		397,100,394.16	13,898,513,795.60
1161 Serv Swg-Ac/Dc-Light Trsf		55		35		278,538,863.27	9,748,860,214.45
1162 Control Cable & Conduit		60		50		470,182,121.77	23,509,106,088.50
1163 Grounding Systems		60		60		219,228,993.30	13,153,739,598.00
1164 Metering Units		15		15		63,617,947.99	954,269,219.85
1166 Switchboards		35		35		709,818,596.82	24,843,650,888.70
1167 Sup Cntrl-Prim H/Ware& Sys		20		20		651,495,596.08	13,029,911,921.60
1168 Sup Cntrl - Prim Appl S/Ware		20		20		23,248,779.19	464,975,583.80
1170 Service Systems		50		50		206,248,622.66	10,312,431,133.00
1175 Transf <=50Kv or <5Mva		50		60		69,901,471.00	4,194,088,260.00
1176 Trnsf <=115Kv or >5Mva		50		50		444,732,814.95	22,236,640,747.50
1177 Transf <=230Kv		50		50		458,240,556.69	22,912,027,834.50
1178 Transf >230Kv		50		40		329,558,627.05	13,182,345,082.00
1179 Transf Instal Cost		50		50		412,908,818.23	20,645,440,911.50
1181 Switching >=34.5Kv		45		40		205,168,942.15	8,206,757,686.00
1182 Switching >=115Kv		45		40		149,001,443.84	5,960,057,753.60
1183 Switching >=230Kv		45		40		177,035,018.13	7,081,400,725.20
1184 Sf6 Switchgear		45		45		388,947,455.93	17,502,635,516.85
1185 Reclosures		40		40		1,538,864.37	61,554,574.80
1186 Misc Switching		45		40		185,461,309.16	7,418,452,366.40
1187 Bus (Rigid & Strain)		45		45		340,586,997.47	15,326,414,886.15
1188 Cable		45		45		141,909,776.30	6,385,939,933.50
1190 Cct Breakers >=230Kv		45		43		326,172,585.20	14,025,421,163.60
1191 Cct Breakers >=115Kv		45		44		122,287,825.85	5,380,664,337.40
1192 Cct Breakers <115Kv		45		47		163,174,682.08	7,669,210,057.76
1193 Cct Breakers Install		45		46		255,315,700.05	11,744,522,202.30
1194 Encld Swgr (All Compnt)		45		45		85,283,967.31	3,837,778,528.95
Station equipment		45		40		4,065,324,602.97	162,612,984,118.80
Total USoA 1715	48 R2.5	42	43 R2.5	43.23		13,205,113,998.20	570,831,235,726.66
1720 Towers and Fixtures							
1230 Steel Twr, Sup & Ftng		90		80		1,623,422,605.95	129,873,808,476.00
1240 Poles Incl Xarm, Guy, Anchr		50		50		778,560,396.22	38,928,019,811.00

Hydro One 2024 Tx BU 210

Description	Current P-Life		Recommended P-Life		Plant		$ x PL
	UsoA	Category	UsoA	Category	UsoA	Category	
1245 Steel Poles		90		80		115,905,630.45	9,272,450,436.00
1249 Composite Poles		80		80		8,007,607.64	640,608,611.20
Tower and Fixtures		75		80		909,267,139.06	72,741,371,124.80
Total USoA 1720	75 R3	73	73 R3	73.20		3,435,163,379.32	251,456,258,459.00
1730 Overhead Conductors and Devices							
1220 Insulators		60		65		291,716,529.18	18,961,574,396.70
1232 Grounding System		50		54		162,069,132.49	8,751,733,154.46
1235 Opt Grnd Wire		50		40		66,489,857.44	2,659,594,297.60
1250 Overhd Conductor All		70		90		1,109,972,927.98	99,897,563,518.20
1252 Switches&Devce		60		60		46,349,552.46	2,780,973,147.60
1254 Retension Costs		60		60		40,619,072.40	2,437,144,344.00
Overhead Conductors and Devices		65		90		886,731,179.59	79,805,806,163.10
Total USoA 1730	70 R4	64	83 R4	82.68		2,603,948,251.54	215,294,389,021.66
1735 Underground Conduit							
Underground Conduit		60		80		2,408,682.78	192,694,622.40
1220 Insulators		60		65		140,166.41	9,110,816.65
1261 Ugrd Conduit		60		80		310,145,278.11	24,811,622,248.80
Total USoA 1735	60 R2	55	80 R2	79.99328		312,694,127.30	25,013,427,687.85
1740 Underground Conductors and Devices							
1262 Ugrd Conductor		55		66		150,297,812.02	9,919,655,593.32
Underground Conductors and Devices		55		66		36,843,456.69	2,431,668,141.54
Total USoA 1740	55 R2	55	66 R2	66		187,141,268.71	12,351,323,734.86
1745 Roads and Trails							
1122 Perm Rds & Surfc Area		25		25		61,719,526.26	1,542,988,156.50
1174 Railway Track		30		30		8,007,704.56	240,231,136.80
1215 Clrng & Overbldng		70		70		162,540,585.61	11,377,840,992.70
1271 Roads & Trails		70		70		48,823,772.30	3,417,664,061.00
Roads and Trails		50		70		261,346,946.13	18,294,286,229.10
Total USoA 1745	60 R4	49	64 R4	64.28933		542,438,534.86	34,873,010,576.10
GENERAL PLANT							
Depreciable							
1905D Land - Depreciable							
1828 Genrl -Comm -Site Improvement		100					
Total USoA 1905D		100					
1908 Buildings and Fixtures							
1612 Genrl -Adm & Serv-Landscaping		50		50		23,919.59	1,195,979.50
1621 Genrl -Adm & Serv_Bld Frame & Mtl		50		50		33,139,210.42	1,656,960,521.00
1622 Genrl -Adm & Serv-Rds & Surfaces		25		25		4,049,783.25	101,244,581.25
1623 Genrl -Adm & Serv-Bld Frame		50		50		15,167,792.73	758,389,636.50
1628 Genrl -Adm & Serv-Fence		30		30		4,152,473.88	124,574,216.40
1650 Genrl - Adm & Serv-Distn Sys		50		50		14,567,580.44	728,379,022.00
1663 Genrl -Adm & Serv_Aux Eq Bld		50		50		13,238,615.36	661,930,768.00
1813 Genrl -Comm-Landscaping		50		50		62,867.30	3,143,365.00
1820 Genrl -Comm-Buildings		50		50		13,855,943.14	692,797,157.00
1853 Genrl -Comm-Str & Footings-Poles		50		50		33,299,587.40	1,664,979,370.00
Buildings and Fixtures		45		50		77,291,190.46	3,864,559,523.00
Total USoA 1908	50 S4	47	50 S4	49.11757		208,848,963.97	10,258,154,139.65
1910 Leasehold Improvements							
Leasehold Improvements		10		10		23,025.22	230,252.20
1624 Genrl -Adm & Serv-Bldgs-Leased		10		10		100,228.00	1,002,280.00
Total USoA 1910	10 S6	10	10 S6	10		123,253.22	1,232,532.20
1922 Computer Hardware - Major							
1653 Genrl -Adm & Serv-Lan Elect Dev		10		10		12,747,100.37	127,471,003.70
1655 Genrl -Adm & Serv-Lan Cable		10		10		672,183.08	6,721,830.80
1656 Genrl -Adm & Serv-Lan Fib Opt		10		10		987,841.57	9,878,415.70
1657 Genrl - Adm & Serv-Sys Software		10		10			0.00
Computer Hardware - Major		10		10		29,491,253.88	294,912,538.80
Total USoA 1922	10 S6	10	10 S6	10		43,898,378.90	438,983,789.00
1955 Communication Equipment							
1654 Genrl - Adm & Serv-Telcm Wire		7		7		2,594,458.32	18,161,208.24
1658 Genrl - Adm & Serv-Telcm Equip		7		7		2,276,159.23	15,933,114.61
1659 Genrl - Adm & Serv-Telcom Sw		7		7		717,040.89	5,019,286.23
1850 Genrl - Comm-Radio Equipment		10		15		53,449,402.96	801,741,044.40
1854 Genrl - Comm-Admin Telcom Equp		7		7		22,999,991.56	160,999,940.92

Hydro One 2024 Tx BU 210

Description	Current P-Life		Recommended P-Life		Plant		$ x PL
	UsoA	Category	UsoA	Category	UsoA	Category	
1863 Genrl - Comm Optical Wire		25		40		96,237,097.86	3,849,483,914.40
1864 Fenrl - Comm-Opt Wire Termtn		20		20		159,734,153.64	3,194,683,072.80
1865 Genrl - Comm-Opgw W Fib Cable		25		40		69,939,422.31	2,797,576,892.40
1870 Genrl - Comm-Power Supply Equp		15		15		20,808,426.03	312,126,390.45
Communication Equipment		20		20		236,036,712.00	4,720,734,240.00
Total USoA 1955	20 R2.5	17	24 R2.5	23.88181		664,792,864.80	15,876,459,104.45
1980 System Supervisory Equipment							
1840 Genrl - Comm-Pwr Line Equip		15		15		172,400,454.73	2,586,006,820.95
1844 Genrl - Comm-Sys Cntrl Comp Eq		6		6		149,272,636.63	895,635,819.78
1846 Genrl - Comm-Dacs Appl S/Ware		6		6		2,678,368.33	16,070,209.98
1847 Genrl - Comm-Dacs Sys S/Ware		6		6		98,568,831.48	591,412,988.88
1860 Genrl - Comm-Pole		25		25		28,802,967.54	720,074,188.50
1864 Genrl - Comm-Opt Wire Termtn		20		20		16,209.30	324,186.00
System Supervisory Equipment		10		15		2,513,384.05	37,700,760.75
Total USoA 1980	10 R4	8	11 R4	10.67076		454,252,852.06	4,847,224,974.84
Amortizable							
1925 Computer Software - Major							
Computer Software Major		6		6		8,563,318.68	51,379,912.08
1657 Genrl - Adm & Serv-Sys Software		6		6		5,156,364.06	30,938,184.36
Total USoA 1925	6 SQ	6	6 SQ	6		13,719,682.74	82,318,096.44

Hydro One 2024 Dx BU 220
P Life Analysis

	Current P-Life		Recommended P-Life		Plant		
	USA Composite	Category	USA Composite	Category	Total USA	Category $	$x Plife
INTANGIBLE PLANT							
1609 Capital Contributions							
Computer software - Capital Contribution		10		10		14,557,260.90	145,572,609.00
2000		10		10		60,904,760.69	609,047,606.90
Total USoA 1609	10 SQ		10 SQ	10.00		75,462,021.59	754,620,215.90
1610 Computer Software							-
Computer Software		10		10		195,321,579.51	1,953,215,795.10
1656		10		10		2,672,766.93	26,727,669.30
1657 Genrl - Adm & Serv-Sys Software		10		10		73,165,912.30	731,659,123.00
Total USoA 1610	10 SQ	10	10 SQ	10.00		271,160,258.74	2,711,602,587.40
DISTRIBUTION PLANT							
1806 Land Rights							
1806 Land Rights							
Land Rights		100		100		61,637,740.28	6,163,774,028.00
1111 Rights & Easmnts <Landscaping>		100		100		1,150,943.93	115,094,393.00
1212 Easmnts & Rights, Purch & Acqui		100		100		7,119,501.00	711,950,100.00
1215 Clrng & Overbldg		100		100		45,004,178.36	4,500,417,836.00
1311 Rural Intl Clring & Ovrbldg		100		100		177,843,246.16	17,784,324,616.00
1313 Rural Easements-Land Rights		100		100		2,589,203.89	258,920,389.00
1314 Rural Perm Rd & Surf Areas		25		25		14,095.24	352,381.00
Total USoA 1806	100 R4		100 R4	100.00		295,358,908.86	29,534,833,743.00
		100					
1808 Buildings & Fixtures				**50**		87,860.72	4,393,036.00
1112 Landscaping		50		50		1,567,578.84	78,378,942.00
1120 Stn Buildings Components		50		50		23,980,694.32	1,199,034,716.00
1270 Serv Structures		50		50		2,250,041.82	112,502,091.00
1312 Rural Landscaping		50		50		698,311.16	34,915,558.00
Total USoA 1808	50 R4	50	50 R4	50.00		28,584,486.86	1,429,224,343.00
1815 Transformer Station Equipment > 50 kV							
Misc. Transformer Station Equipment > 50 kV		50		60		26,649,370.99	1,598,962,259.40
1113 Site Imprv - Excl Fence, Rd, Easmt		50		50		10,322,750.81	516,137,540.50
1122 Perm Rds & Surfc Area		25		60		3,416,346.29	204,980,777.40
1123 Cost Equip Foundations, Excav		50		65		12,241,338.07	795,686,974.55
1127 Steel/Pipe Struc for Switch Eq		50		65		13,835,017.31	899,276,125.15
1128 Fences, Gates, Bldg		30		30		7,716,703.81	231,501,114.30
1150 Rot Elec Eqp (No Wind'G)		65		20		129,369.18	2,587,383.60
1152 Capacitors		35		35		762,947.20	26,703,152.00
1155 Regulators Incl Instal Cost		40		40		2,057,108.32	82,284,332.80
1160 Misc Stn Eqp - Trsf/Volt Trsf		40		40		12,472,099.83	498,883,993.20
1161 Serv Swg - Ac/Dc-Light Trsf		50		55		2,398,116.86	131,896,427.30
1162 Control Cable & Conduit		50		60		3,577,327.09	214,639,625.40
1163 Grounding Systems		50		60		8,540,638.85	512,438,331.00
1164 Metering Units		15		15		7,880,343.08	118,205,146.20
1166 Switchboards		25		40		1,272,928.69	50,917,147.60
1167 Sup Cntrl - Prim H/Ware & Sys		20		20		1,253,618.22	25,072,364.40
1168 Sup Cntrl - Prim Appl S/Ware		20		20		646,032.32	12,920,646.40
1170 Service Systems		50		50		80,311.73	4,015,586.50
1175 Transf <=50Kv or <5Mva		50		50		6,557,178.71	327,858,935.50
1176 Transf <=115Kv or >5Mva		50		50		59,198,881.90	2,959,944,095.00
1177 Transf <=230Kv		50		50		7,473,860.35	373,693,017.50
1179 Transf Instal Cost		50		50		13,310,405.74	665,520,287.00
1181 Switching >=34.5Kv		40		40		8,663,811.65	346,552,466.00
1182 Switching >=115Kv		40		40		3,554,544.83	142,181,793.20
1184 Sf6 Switchgear		40		40		2,622,092.57	104,883,702.80
1185 Reclosures		40		40		22,978,138.30	919,125,532.00
1186 Misc Switching		40		40		3,336,473.20	133,458,928.00
1187 Bus (Rigid & Strain)		40		40		4,996,837.11	199,873,484.40
1188 Cable		40		40		4,488,707.30	179,548,292.00
1190 Cct Breakers >=230Kv		40		40		2,997.00	119,880.00
1191 Cct Breakers >=115Kv		40		40		706,868.17	28,274,726.80
1192 Cct Breakers <115Kv		40		40		560,371.02	22,414,840.80
1193 Cct Breakers Install		40		40		130,016.25	5,200,650.00
1194 Encld Swgr (All Compnt)		40		30		215,368.84	6,461,065.20
Total USoA 1815	48 R2.5	42	48 R2.5	48.58		254,048,921.59	12,342,220,623.90
1820 Distribution Station Equipment < 50 kV							
Misc Distribution Statnio Equipment < 50 kV		60		60		239,810,288.62	14,388,617,317.20
1113 Site Imprv - Excl Fence, Rd, Easmt		50		50		21,557,194.07	1,077,859,703.50
1122 Perm Rds & Surfc Area		60		60		8,514,814.62	510,888,877.20
1123 Cost Equip Foundations, Excav		60		65		41,051,912.96	2,668,374,342.40
1127 Steel/Pipe Struc for Switch Eq		50		65		37,169,400.56	2,416,011,036.40
1128 Fences, Gates, Bldg		50		30		34,288,220.72	1,028,646,621.60
1150 Rot Elec Eqp (No Wind'G)		65		20		1,150,423.64	23,008,472.80
1151 Rot Elec Eqp (Wind'Gs)		65		20		275,616.13	5,512,322.60
1152 Capacitors		35		35		426,169.58	14,915,935.30
1155 Regulators Incl Instal Cost		40		40		18,950,170.69	758,006,827.60
1159 Mobile Sub-Stations		30		30		27,914,301.49	837,429,044.70
1160 Misc Stn Eqp - Trsf/Volt Trsf		30		40		53,552,795.84	2,142,111,833.60
1161 Serv Swg - Ac/Dc-Light Trsf		50		55		4,799,474.21	263,971,081.55
1162 Control Cable & Conduit		50		60		7,095,277.23	425,716,633.80
1163 Grounding Systems		50		60		29,975,433.22	1,798,525,993.20
1164 Metering Units		12		15		96,245,560.19	1,443,683,402.85

Hydro One 2024 Dx BU 220
P Life Analysis

	Current P-Life		Recommended P-Life		Plant	
	USA Composite	Category	USA Composite	Category	Total USA Category $	$x Plife
1166 Switchboards		25		40	2,129,319.39	85,172,775.60
1167 Sup Cntrl - Prim H/Ware & Sys		15		20	8,697,191.79	173,943,835.80
1168 Sup Cntrl - Prim Appl S/Ware		15		20	590,086.35	11,801,727.00
1170 Service Systems		50		50	309,677.93	15,483,896.50
1173 Transf <=50Kv & >5Mva		50		50	100,522,882.71	5,026,144,135.50
1175 Transf <=50Kv or <5Mva		50		50	78,846,950.43	3,942,347,521.50
1179 Transf Instal Cost		50		50	37,299,498.82	1,864,974,941.00
1181 Switching >=34.5Kv		50		40	22,121,457.78	884,858,311.20
1184 Sf6 Switchgear		35		40	2,246,947.24	89,877,889.60
1185 Reclosures		40		40	50,473,985.79	2,018,959,431.60
1186 Misc Switching		50		45	8,231,719.55	370,427,379.75
1187 Bus (Rigid & Strain)		50		45	7,587,069.84	341,418,142.80
1188 Cable		50		45	12,678,302.89	570,523,630.05
1192 Cct Breakers <115Kv		40		45	521,795.70	23,480,806.50
1193 Cct Breakers Install		40		45	197,089.97	8,869,048.65
1194 Encld Swgr (All Compnt)		40		40	3,298,832.47	131,953,298.80
Total USoA 1820	48 R2.5	29	48 R2.5	47.33	958,529,862.42	45,363,516,218.15
1825 - Distributed Energy Resources ("DER)"						
Batteries				20	9,054,010.26	181,080,205.20
				20.00	9,054,010.26	181,080,205.20
1830 Poles, Towers and Fixtures						
Unidentfied		47		60	2,787,242,333.16	167,234,539,989.60
1230 Steel Twr, Sup & Ftng		75		75	1,089,605.11	81,720,383.25
1240 Poles Incl Xarm, Guy, Anchr		60		60	672,523,665.71	40,351,419,942.60
1245 Steel Poles		75		75	4,756,792.70	356,759,452.50
1249 Composite Poles		80		80	17,610,989.72	1,408,879,177.60
1340 Rural supports-Wood,Concret		55		60	2,376,284,059.92	142,577,043,595.20
1349 Steel Poles Support		75		75	5,318,773.99	398,908,049.25
Total UsoA 1830	55 R2	55	60 R2	60.09	5,864,826,220.31	352,409,270,590.00
1835 Overhead Conductors and Devices						
Unidentfied		45		45	106,815,640.40	4,806,703,818.00
1220 Insulators		45		45	76,912,773.64	3,461,074,813.80
1232 Grounding System		45		45	2,371,020.16	106,695,907.20
1235 Opt Grnd Wire		50		50	2,905.80	145,290.00
1250 Overhd Conductor All		60		65	375,882,151.39	24,432,339,840.35
1252 Switches & Devce		40		40	80,336,609.35	3,213,464,374.00
1320 Rural Switches/Load Interptr		40		40	334,908,959.76	13,396,358,390.40
1321 Rural Oil Sectnizer & Reclsr Sw		40		40	36,033,103.76	1,441,324,150.40
1322 Rural Instasectnlr & Rclsr Sw		45		45	26,722,272.12	1,202,502,245.40
1330 Rural Conductor Prim & Sec Overh		60		65	1,128,389,876.87	73,345,341,996.55
1376 Rural Voltage Regulators		40		40	26,734,108.10	1,069,364,324.00
1377 Rural Instl Vltge Regulators		40		40	13,468,663.20	538,746,528.00
1378 Rural Capacitors		40		40	10,337,433.07	413,497,322.80
1379 Rural install Capacitors		40		40	4,794,638.96	191,785,558.40
Total USoA 1835	58 R2	55	58 R2	57.39	2,223,710,156.58	127,619,344,559.30
1840 Undergorund Conduit						
1261 Ugrd Conduit		50		60	32,762,341.47	1,965,740,488.20
Total USoA 1840	60 R1	50	60 R1	60.00	32,762,341.47	1,965,740,488.20
1845 Underground Conductors and Devices						
Unidentfied		30		30	46,970,973.89	1,409,129,216.70
1231 Condctr Submarine Cbl		30		20	1,890,787.70	37,815,754.00
1262 Ugrd Conductor		30		30	26,623,046.96	798,691,408.80
1293 Ugrd Conductor Primary		30		30	1,797,749.53	53,932,485.90
1331 Rural Condctr Submarine Cbl		30		20	157,916,115.86	3,158,322,317.20
1393 Rural U/grd Conductor-Prime		30		30	214,574,304.79	6,437,229,143.70
1394 Rural U/Grd Condr Sec Serv		30		40	479,431,199.10	19,177,247,964.00
1395 Rural U/Grd Fuse Housing		30		30	54,940,084.28	1,648,202,528.40
Total USoA 1845	33 R3	30	33 R3	33.25	984,144,262.11	32,720,570,818.70
1850 Line Transformers						
Unidentfied		40		40	66,228,434.44	2,649,137,377.60
1255 Dx - Subtx Transformers		40		40	5,712,888.34	228,515,533.60
1256 Dx - Subtx Trnsfmrs Install		40		40	3,875,380.26	155,015,210.40
1295 U/GRD Fuse Housing		40		40	2,610,797.95	104,431,918.00
1341 Rural OH Trfmrs <=25 Kva		40		40	372,314,141.55	14,892,565,662.00
1342 Rural OH Trfmrs >25 & <=50 Kva		40		40	130,844,024.44	5,233,760,977.60
1343 Rural OH Trfmrs >50 & <=75 Kva		40		40	43,844,959.46	1,753,798,378.40
1344 Rural OH Trfmr >75 & <=100 Kva		40		40	36,829,348.86	1,473,173,954.40
1345 Pole Top Trfs >100 & <=200 Kva		40		40	19,829,905.33	793,196,213.20
1346 Pole Top Trfs >200 & <=300 Kva		40		40	9,863,976.16	394,559,046.40
1347 Dx - Ptop Trfmrs >300 & <=500 Kva		40		40	1,072,943.35	42,917,734.00
1348 Dx - Pole Top Trfmrs >500 Kva		40		40	931,210.54	37,248,421.60
1351 Rural Trsf Instal		40		40	874,912,919.82	34,996,516,792.80
1385 Rural U/Grd Trsf 0-50Kva		40		40	110,313,463.03	4,412,538,521.20
1386 Rural U/Grd Trsf 51-75 Kva		40		40	49,920,018.44	1,996,800,737.60
1387 Rural U/Grd Trsf 76-100 Kva		40		40	45,403,335.05	1,816,133,402.00
1388 Rural U/Grd Trsf 101-200Kva		40		40	19,769,896.11	790,795,844.40
1389 Rural U/Grd Trsf 201-300Kva		40		40	20,006,880.56	800,275,222.40
1390 Rural U/Grd Trsf 301-500Kva		40		40	36,053,188.82	1,442,127,552.80
1391 Rural U/Grd Trsf 501-750Kva		40		40	13,339,218.65	533,568,746.00
1392 Rural U/Grd Trsf >750Kva		40		40	10,737,034.85	429,481,394.00
1396 Rural U/Grd Trfmrs Instal		40		40	292,721,583.17	11,708,863,326.80
Total USoA 1850	40 R2	40	40 R2	40.00	2,167,135,549.18	86,685,421,967.20

Hydro One 2024 Dx BU 220
P Life Analysis

	Current P-Life		Recommended P-Life		Plant		
	USA Composite	Category	USA Composite	Category	Total USA	Category $	$x Plife
1860 Meters							
All conventional meters are now 1 category		20		18		700,290,815.79	12,605,234,684.22
1356 Meters - Watthour, Single Ph		20		18		4,662,868.93	83,931,640.74
1358 Metering Polyphase		20		18		2,641,057.98	47,539,043.64
1360 PRIM M UNIT >=75 (MAT ONLY)		20		18		42,878.74	771,817.32
1361 Install - W/Hr & Dmd M S Ph		20		18		12,795,217.96	230,313,923.28
1362 Install - Meters Polyphase		20		18		2,070,148.51	37,262,673.18
1363 PRIM M UNIT<'75(MAT&INST)		20		18		8,881.31	159,863.58
1365 - Smart meters. See below		15		18		116,884,200.03	2,103,915,600.54
Total USoA 1860 excluding 1365	18 R3	20	18 R3	18.00		839,396,069.25	15,109,129,246.50
1555 Smart Meters (No additions since 2016)							
1365 Smart Mtr - Incl Cost & Inst		18		13		295,181,274.07	3,837,356,562.91
Total USoA 1555	18 R3	18	13 S1.5	13.00		295,181,274.07	3,837,356,562.91
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures							
Unidentfied		50		50		127,108,781.35	6,355,439,067.50
1612 Genrl - Adm & Serv-Landscaping		50		50		88,003.51	4,400,175.50
1621 Genrl - Adm & Serv Bld Frame & Mtl		50		50		51,623,437.29	2,581,171,864.50
1622 Genrl - Adm & Serv-Rds & Surfaces		50		25		16,190,101.96	404,752,549.00
1623 Genrl - Adm & Serv-Bld Frame		50		50		51,164,220.96	2,558,211,048.00
1628 Genrl - Adm - & Serv-Fence, Gate		30		30		1,924,207.00	57,726,210.00
1650 Genrl - Adm & Serv-Distn Sys		50		50		1,890,884.97	94,544,248.50
1663 Genrl - Adm & Serv Aux Eq Bld		50		50		14,332,208.34	716,610,417.00
1820-				50		2,744,366.48	137,218,324.00
1853 Communication building		50		50		134,622.20	6,731,110.00
Total USoA 1908	50 S4	49	48 S4	48.34		267,200,834.06	12,916,805,014.00
1910 Leasehold Improvements							
Unidentfied		10		10		9,990,295.48	99,902,954.80
1624 Genrl - Adm & Serv-Bldgs-Leased		10		10		7,965,651.36	79,656,513.60
Total USoA 1910	10 S6	10	10 S6	10.00		17,955,946.84	179,559,468.40
1922 Computer Hardware - Major							
1653 Genrl - Adm & Serv-Lan Elect Dev		10		10		2,035,010.44	20,350,104.40
1655 Genrl - Adm & Serv-Lan Cable		10		10		2,290,724.44	22,907,244.40
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10		161,333.44	1,613,334.40
1657 Genrl - Adm & Serv-Sys Software		10		10		246,062.79	2,460,627.90
Total USoA 1922	10 S6	10	10 S6	10.00		4,733,131.11	47,331,311.10
1955 Communication Equipment							
Communication equipment		10		20		1,810,035.37	36,200,707.40
1654 Genrl - Adm & Serv-Telcm Wire		7		7		7,108,308.21	49,758,157.47
1656 Genrl - Adm & Serv-Lan Fib Opt		10		10		117,949.00	1,179,490.00
1658 Genrl - Adm & Serv-Telcm Equip		7		7		11,664,068.44	81,648,479.08
1659 Genrl - Adm & Serv-Telcom Sw		7		7		186,059.32	1,302,415.24
1850 Genrl - Comm Radio Equipment		10		15		7,669,110.22	115,036,653.30
1854 Genrl - Admin Telcom Equip		7		7		668,746.14	4,681,222.98
1863 Genrl - Comm Optical Wire		25		40		222,028.51	8,881,140.40
1864 Genrl - Comm Optical Wire Terrntn		7		20		211,851.96	4,237,039.20
1870 Genrl - Comm Power Supply Equp		15		15		2,972.00	44,580.00
Total USoA 1955	7 S6	7	10 S6	10.21		29,661,129.17	302,969,885.07
1980 System Supervisory Equipment							
1840 Genrl - Comm Pwr Line Equip		15		15		138,912.18	2,083,682.70
1844 Genrl - Comm Sys Cntrl Comp Eq		6		6		7,276,797.18	43,660,783.08
1847 Genrl - Comm Dacs Sys S/Ware		6		6		126,720,242.73	760,321,456.38
1860 Genrl - Comm Pole Comm Cab Bths		25		25		66,364.33	1,659,108.25
Total USoA 1980	6 L2	6	6 L2	6.02		134,202,316.42	807,725,030.41
1985 Sentinel Lightning Rental Units							
Genrl - Dist Sentnal Lite Units		27		30		1,000.00	30,000.00
1374 Genrl - Dist Sentnal Lite Units		27		30		15,406,748.95	462,202,468.50
Total USoA 1985	27 R3	30	30 R3	30.00		15,407,748.95	462,232,468.50
Amortizable							
1925 Computer Software - Major							
Unclassified		6		6		2405503.17	14,433,019.02
1657 Genrl - Adm & Serv-Sys Software		6		6		0.00	0.00
Total USoA 1925	6 SQ	6	6 SQ	6.00		2,405,503.17	14,433,019.02

Hydro One 2024 Dx BU 300

Description	Current P-Life		Recommended P-Life		Plant		
	UsoA	Category	UsoA	Category	UsoA	Category	$x Plife
INTANGIBLE PLANT							
1610 Computer Software							
1656 Genrl- Adm & Serv- Lan Fib Opt		10			10	30,330,584.67	303,305,846.70
1657 Genrl - Adm & Serv-Sys Software		10			10	186,776,541.25	1,867,765,412.50
Computer Software		10			10	363,181,836.25	3,631,818,362.50
Total USoA 1610	12 SQ	10		10 SQ	10.00	580,288,962.17	5,802,889,621.70
GENERAL PLANT							
Depreciable							
1908 Buildings and Fixtures							
1621 Genrl - Adm & Serv-Bld Frame&Mtl		50			50	43,195,753.41	2,159,787,670.50
1622 Genrl - Adm & Serv-Rds&Surfaces		25			25	6,349,922.59	158,748,064.75
1623 Genrl - Adm & Serv-Bld Frame		50			50	42,180,486.42	2,109,024,321.00
1628 Genrl - Adm & Serv-Fence,Gate		30			30	1,419,856.06	42,595,681.80
1650 Genrl - Adm & Serv-Distn Sys		50			50	987,633.84	49,381,692.00
1663 Genrl - Adm & Serv-Aux Eq Bld		50			50	14,130,075.65	706,503,782.50
1812 Genrl- Comm-Road and Surface Areas		50			25	2,408.33	60,208.25
Buildings and Fixtures		50			50	201,373,856.70	10,068,692,835.00
Total USoA 1908	50 S4	47		50 S4	49.40	309,639,993.00	15,294,794,255.80
1910 Leasehold Improvements							
1624 Genrl - Adm & Serv-Bldgs-Leased		10			15	45,291,202.08	679,368,031.20
Leasehold Improvemetns		10			15	3,604,768.78	54,071,531.70
Total USoA 1910	10 S6	10		15 S6	15.00	48,895,970.86	733,439,562.90
1922 Computer Equipment - Hardware							
Unidentifed		10			10	40,722,084.58	407,220,845.80
1653 Genrl - Adm & Serv-Lan Elect Dev		10			10	11,836,022.83	118,360,228.30
1655 Genrl - Adm & Serv-Lan Cable		10			10	505,356.03	5,053,560.30
Total USoA 1922	10 S6	10		10 S6	10.00	53,063,463.44	530,634,634.40
1955 Communication Equipment							
1654 Genrl - Adm & Serv-Telcm Wire		7			7	2,396,025.54	16,772,178.78
1658 Genrl - Adm & Serv-Telcm Equip		7			7	15,285,792.87	107,000,550.09
1850 Genrl - Comm-Radio Equipment		10			15	11,318.00	169,770.00
1854 Genrl - Comm-Admin Telcom Equp		7			7	4,433,154.71	31,032,082.97
1870		?			7	313,718.27	2,196,027.89
Total USoA 1955	7 S6	7		7 S6	7.00	22,440,009.39	157,170,609.73
1980 System Supervisory Equipment							
1840 Genrl - Comm-Pwr Line Equip		15			15	389,016.66	5,835,249.90
1844 - Genrl - Comm-Sys Cntrl Comp Eq		6			6	3,705,164.00	22,230,984.00
1847 Genrl- Comm-DASC Sys S/Ware		6			6	3,240,917.71	19,445,506.26
System Supervisory Equipment		7			15	12,347,051.82	185,205,777.30
Total USoA 1980	7 S6	6		12 S6	11.82	19,682,150.19	232,717,517.46
Amortizable							
1915 Office Furniture and Equipment							
S007 Mfa - 7 Yr Sl		7			7	6,656,346.14	46,594,422.98
Total USoA 1915	7 SQ	7		7 SQ	7.00	6,656,346.14	46,594,422.98
1920 Computer Hardware - Minor							
S005 Computers - 40% Db (Default)		5			5	105,523,881.10	527,619,405.50
Total USoA 1920	5 SQ	5		5 SQ	5.00	105,523,881.10	527,619,405.50
1925 Computer Software - Major							
1657 Genrl - Adm & Serv-Sys Software		6			6	744,621.40	4,467,728.40
Computer Hardware - Major		6			6	13,010,919.51	78,065,517.06
Total USoA 1925	6 SQ	6		6 SQ	6.00	13,755,540.91	82,533,245.46
1935 Stores Equipment							
S008 Mfa - 8Yr Sl(Def)		8			8	357,652.50	2,861,220.00
Total USoA 1935	8 SQ	8		8 SQ	8.00	357,652.50	2,861,220.00
1940 Tools, Shop and Garage Equipment							
S006 Mfa - 6Yr Sl(Def)		8			6	12,002,871.22	72,017,227.32
Total USoA 1940	8 SQ	8		6 SQ	6.00	12,002,871.22	72,017,227.32
1945 Measurement and Testing Equipment							
S005 Mfa - 5Yr Sl(Def)		5			5	14,173,858.70	70,869,293.50
Total USoA 1945	5 SQ	5		5 SQ	5.00	14,173,858.70	70,869,293.50
1960 Miscellaneous Equipment							
S005 Mfa - 5Yr Sl(Def)		5			5	8,993,043.16	44,965,215.80
Total USoA 1960	5 SQ	5		5 SQ	5.00	8,993,043.16	44,965,215.80

APPENDIX F

Alliance Consulting Group –

Background and Qualifications

Company Profile

Alliance Consulting Group is an international consulting firm formed in 2004 by Dane Watson. In addition to the partner, Alliance also has four full-time Senior Consultants, Dr. Karen Ponder, Ms. Rhonda Watts, Ms. Rebecca Richards, and Mr. Rich Bennett, as well as other support staff. Alliance is dedicated to providing quality consulting and expert services to the utility industry. Our professionals have more than 190 years of combined experience around the utility industry, and we have been employed in the industry as utility employees and consultants.

The Alliance Consulting Group has performed over 400 depreciation studies for electric, gas, steam, water, wastewater, cable and communications utilities across the country since its founding by Mr. Watson in 2004. These utilities encompass regulated, non-regulated, municipal and federal agencies. The studies were provided in a timely manner with thorough analysis.

II: Personnel

PEOPLE

Dane Watson, project Manager

The project manager will be Dane Watson of Alliance. He was previously employed as a Property Accounting Services Manager for TXU and has twenty years of experience at a Fortune 100 utility in property accounting, depreciation and valuation. He has managed fixed asset accounting for regulated entities and non-regulated entities. He has an industry-wide reputation with significant experience as an expert witness in depreciation, valuation and rate base areas and has provided testimony and support in many state regulatory commission dockets. Mr. Watson has conducted depreciation studies for a variety of assets for both regulated and non-regulated companies. He has held a number of national industry roles related to depreciation and property accounting including twice chairing the Plant Accounting and Valuation Committee of the Edison Electric Institute. He has attended all the classes offered by the Depreciation Programs, Inc. (DPI) and continues to re-fresh his training by teaching various depreciation related seminars across the country. He developed the training materials for the Intermediate and Advanced Training sessions of the Society for Depreciation Professionals and teaches a number of courses. He twice served as general editor of the industry publication "Introduction to Depreciation and Net Salvage of Public Utility Plant and Plant of Other Industries", is contributing editor of other industry publications and is a frequent speaker at conferences on depreciation related issues. Mr. Watson led the industry adoption of SFAS 143 and was industry panelist before FERC (FERC Docket 02-0700) testifying on their implementation of SFAS 143. He also served as project lead (functional) in the development of both automated regulated group depreciation and fixed asset systems and item based fixed asset and depreciation systems while at TXU. Mr. Watson is a Licensed Professional Engineer in the State of Texas (PE) and a Certified Depreciation Professional (CDP).

Karen Ponder, Senior Consultant

Dr. Karen Ponder is a Senior Consultant at Alliance with over 48 years of experience in utility financial matters. Dr. Ponder is a Certified Depreciation Professional (CDP) and has a doctorate degree in engineering valuation from Iowa State University where her dissertation was entitled, "Some Aspects of Statistically Modeling the Simulated Plant Record Method." She is considered a subject matter expert in depreciation and capital recovery in the utility industry and has performed studies for regulated and non-regulated entities involving property of various types. Dr. Ponder has conducted statistical analysis of life and net salvage components and incorporated knowledge of equipment failure, new technological trends, and company practices to develop life and net salvage estimates. She has provided support during rate case litigation including study write-up, testimony, and responses to interrogatories. She was an instructor for many years at Depreciation Programs, Inc. in Kalamazoo, Michigan and serves as a faculty member for the Society of Depreciation Professional's Annual Training courses.

Rhonda Watts, Senior Consultant

Rhonda Watts is a Senior Consultant at Alliance who participates in the various activities related to the completion of the depreciation study and provides Expert Witness testimony if needed. Rhonda has over thirty years of experience in utility accounting, depreciation and regulatory matters. She is considered a subject matter expert in depreciation and capital recovery in the utility industry and has performed studies for regulated entities involving property of electric, gas, water and wastewater and communication utilities. She has conducted statistical analysis of life and net salvage components and incorporated knowledge of equipment failure, new technological trends, and company practices to develop life and net salvage estimates. She has provided support during rate case litigation including study write-up, testimony, and responses to interrogatories. Rhonda has also testified before three state regulatory bodies.

Rebecca Richards, Senior Consultant

Rebecca Richards is a Senior Consultant at Alliance and a Certified Depreciation Professional (CDP). She was previously employed as a Team Lead of Property Accounting at We Energies and has nine years of experience at a Fortune 500 company in utility property accounting, depreciation and areas of corporate finance. She has a vast working knowledge of fixed asset and finance systems including SAP, UI, and PowerPlan. Rebecca has managed fixed asset accounting for both regulated and non-regulated entities. She has coordinated depreciation studies for all types of utilities including electric, gas, water, and steam heating. In 2025, she is serving as Past-President of the Society of Depreciation Professionals (SDP). She has also served as an SDP Trainer Intern since 2024 and on the board of directors since 2022.

Richard (Rich) Bennett, Senior Consultant

Rich Bennett is a Senior Consultant with Alliance Consulting Group with over 42 years of experience in utility financial matters. He is a Certified Depreciation Professional, a designation sanctioned and issued by the Society of Depreciation Professionals (SDP). Prior to joining Alliance,

Rich was a Senior Manager with UCG Solutions, LLC., a Senior Solution Architect with PowerPlan, Inc., and a Principal Manager with Southern California Edison (SCE). He has filled various management and analytical roles in the Regulatory, Depreciation, Operational Finance, and Fixed Asset arenas. During his over 30-year tenure with SCE, Rich has performed numerous depreciation studies and has testified on depreciation and decommissioning matters at the California Public Utilities Commission (CPUC) and the Federal Energy Regulatory Commission (FERC). Rich has made presentations on depreciation related issues at the SDP annual conference and the Edison Electric Institute/American Gas Associations (EEI/AGA) Property Accounting & Valuation Committee. He continues to be an instructor on depreciation topics at the annual training offered by SDP. Rich contributed to the EEI/AGA publication Introduction to Depreciation for Public Utilities and Other Industries. Mr. Bennett holds a Bachelor of Science Degree in Business, with an emphasis in Management Science and Production, from the California State Polytechnic University, Pomona, and an M.B.A. from the University of La Verne. He completed the entire roster of courses offered by Depreciation Programs, Inc. (DPI), attended EEI/AGA courses on Ratemaking and Utility Accounting, and completed training on rate case preparation offered by Arthur Anderson. Rich has also been a member of the EEI/AGA Property Accounting & Valuation Committee and is currently the acting Secretary on the SDP Board of Directors.

RESUMES OF DEDICATED CONSULTANTS

DANE A. WATSON, PE, MBA, CDP

MANAGING PARTNER, ALLIANCE CONSULTING GROUP

Profile

- 41 years of experience in engineering, utility depreciation, valuation, and property accounting.
- Industry wide reputation with significant experience as Expert Witness, in depreciation, valuation, and rate base areas.
- Proven experience in effectively managing property systems and reengineering processes/ systems to achieve significant cost savings.
- Goal-Oriented, "outside the box" thinker with demonstrated strong leadership and communication capabilities.
- Professional Engineer (PE) and Certified Depreciation Professional (CDP) as recognized by the Society of Depreciation Professionals

Relevant Experience and Accomplishments

- Depreciation and Asset Accounting
  - Conducted over 365 depreciation studies for electric (generation, transmission, and distribution), gas (transmission, distribution, LNG and storage), water/wastewater, telecom and mining companies (regulated and non-regulated) and supported over 35 state regulatory bodies and FERC.
  - Ongoing teaching of depreciation (basic and advanced) in many industry venues (EEI/AGA, SDP, Michigan State, State Commissions).
  - Lead or served in numerous national industry roles related to depreciation and property accounting including twice chairing the Plant Accounting and Valuation Committee of the

    Edison Electric Institute and twice chairing the Society of Depreciation Professionals.

  - Served as gas and electric industry Project Manager for the implementation of SFAS 143.
  - Served as general editor for "Introduction to Depreciation and Net Salvage".
  - Managed fixed asset accounting, depreciation accounting and analysis, lease accounting, inventory accounting, transportation accounting and records management for one of the largest electric and gas utilities in the US.
- System/Process Reengineering
  - Reengineered fixed asset process and managed redesign of a Fixed Asset system to create a $1.5-$2.0 million savings per year.
  - Designed and implemented a new leased asset tracking and payment system that enabled reduction of errors in lease payments by $3-$4 million per year.
  - Designed and implemented an internal shared asset tracking and allocation system to meet stringent affiliate transaction rules.
  - Championed, designed and implemented imaging system to replace paper and microfilm document storage system saving over $1 million per year.

Employment History

- 2004-present
  - Partner Alliance Consulting Group, Plano, TX

- 1996-2004
  - Manager of Property Accounting Services TXU Business Services, Dallas, TX

    Testified in 15 rate or restructuring proceedings before various Commissions including the Texas Railroad Commission, the Texas Public Utilities Commission and the FERC. Lead Sarbanes-Oxley implementation for property processes. During tenure, increased scope to managing all fixed asset and construction accounting, inventory accounting, transportation accounting, and fixed asset accounting systems. Lead efforts to convert 14 companies to a new fixed asset system. Restructured valuation system to provide a 90% faster response time. Implemented new construction/fixed asset systems that facilitated a 12 FTE reduction in staff. Built state-of-the-art lease accounting system to handle reporting and payment of all TXU leases. Built highly automated imaging system to replace microfilm and paper document storage and retrieval system reducing costs and shortening response time.

- 1992-1996
  - Technical Support Manager Texas Utilities Generating Company, Dallas, TX

    Managed group responsible for depreciation and valuation analysis for TXU as well as special engineering projects. Responsible for teaching and running engineering economics analysis for large capital projects. Managed nuclear plant decommissioning studies and electrical line loss allocation studies.

- 1985-1992
  - Associate Engineer to Senior Engineer Texas Utilities Generating Company, Dallas, TX

    Given increasing responsibility related to depreciation and valuation program creation,

    valuation analysis, depreciation analysis, training TXU employees in engineering economics, report preparation, writing and supporting depreciation testimony before the Texas Public Utilities Commission.

Education

- M.B.A., General Business, Amberton University, Garland, TX
- B.S., Electrical Engineering, University of Arkansas

Certification

- Certified Depreciation Professional, since 2004 with certification renewals

Honors and Awards

- Professional Engineer (TX)
- Certified Depreciation Professional ("CDP")
- Senior Member of the Institute of Electronics and Electrical Engineers ("IEEE")
- IEEE 3rd Millennium Medal

- IEEE Region 5 Treasurer, Audit Committee Chair, IEEE-USA Secretary Treasurer, IEEE MGA Treasurer, IEEE Finance Committee Member
- American Association of Engineering Societies (AESS) Treasurer
- Twice Chair of the Edison Electric Institute ("EEI") Property Accounting and Valuation Committee
- Former Board member and twice President of the Society of Depreciation Professionals

KAREN HALLAMAN PONDER, PH.D., CDP

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- Recognized expert in the field, particularly with regard to historical analyses of life and net salvage.
- More than 48 years of experience in utility property accounting, depreciation, and valuation.
- Involved in dozens of depreciation studies through all facets of the process including regulatory support through information discovery and rate proceedings.
- Prepared depreciation studies for all types of utilities including electric, gas telecommunications, water, and wastewater.
- Taught courses on depreciation models and theory, actuarial analysis, and simulated plant record analysis for over 40 years in nationally recognized training venues.
- Certified Depreciation Professional (CDP) as recognized by the Society of Depreciation Professional

Professional Experience

- 2004-present
  - Senior Consultant - Alliance Consulting Group, Plano, TX
    Involved in all aspects of conducting depreciation studies from data gathering to analysis and supporting recommendations through testimony. 20 years of experience in using Power Plan stand alone depreciation studies software. Participated in more than 330 depreciation studies. Subject matter expert on depreciation theory and data analytics. Performed depreciation studies for various entities ranging from electric, gas, mining, telecommunications, water, and wastewater.
- 1993-2004
  - Capital Recovery Specialist - Texas Utilities, Dallas, TX.
    Responsible for studies and analysis of asset data in a variety of assignments ranging from the engineering department to property accounting.
- 1985-1997
  - Faculty Member - Depreciation Programs of Kalamazoo, Michigan
    Taught classes on Depreciation Models, Simulated Plant Record Method Analysis, and Actuarial Analysis. Participants included company representatives, staff of various state commissions and consultants from the United States and Canada.
- 1978-1984
  - Senior Engineer - Texas Utilities, Dallas, TX.
    Held positions of increasing responsibility in various utility departments including general office engineering, economic research, and budgets. Responsibilities included preparing depreciation studies and rate case support.

Education

- Ph.D., Industrial Engineering with specialty in Engineering Valuation, Iowa State University

- M.S., Statistics, Iowa State University
- B.S., Mathematical Statistics *summa cum laude*, McNeese State University, Lake Charles, LA

Certification

- Certified Depreciation Professional, since 2021

Memberships

- Society of Depreciation Professionals
- Society of Depreciation Professionals, Training Faculty, 2007 to present
- Society of Depreciation Professionals, Secretary, 2014 to 2015
- Society of Depreciation Professionals, Training Deputy Chair, 2018 to present
- Society of Depreciation Professionals, Website and Newsletter Chair, 2023
- Society of Depreciation Professionals, At Large Board Member, 2024 to 2025.

RHONDA WATTS

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- 36 years of experience in utility accounting, property accounting, depreciation, and regulatory processes. Participated in over 265 depreciation studies.
- Industry reputation with experience as Expert Witness in depreciation.
- Performed numerous depreciation studies through all facets of the process including regulatory support and testimony. Experienced focus on historical analyses of life and net salvage.
- Prepares depreciation studies for all types of utilities including electric, gas, telecommunication, water, and wastewater.

Professional Experience

- 2009-present
  - Senior Consultant - Alliance Consulting Group, Plano, TX

    Senior Consultant involved in all aspects of depreciation studies. Performs depreciation studies for electric, gas, communication, water, and wastewater utility clients. Provides study support during rate case litigation including drafting study narratives and testimony and responding to interrogatories. Provided testimony before state regulatory bodies.
- 1996-2009
  - Senior Manager - Deloitte & Touche LLP

    Senior Manager in the Energy and Resources Group with concentration in the areas of depreciation and fixed asset accounting systems. Areas of expertise include the principles and procedures of capital recovery, utility organization, accounting and information systems and regulatory practices.
- 1990-1996
  - Accountant - Nevada Power Company

    Accountant and Analyst positions of increasing responsibility. Areas of responsibility include plant and receivables accounting, depreciation study updating, rate case schedule preparation and support, regulatory compliance reporting, financial report preparation, and budget variance analysis.
- 1986-1990
  - Primary Accountant - UNLV Foundation

    Primary Accountant responsible for the proper processing and accounting of donations to the UNLV Foundation in support of academic excellence. Also compiled financial reports for the Board of Directors and Trustees.

Major Projects

- Conducted numerous depreciation studies and assisted in regulatory support through testimony, information discovery and rate proceedings for various electric, gas, water, and wastewater utility companies.

- Assisted various audit teams in the review of client's implementation of FASB 143 and Interpretation No. 47 (Asset Retirement Obligations). The review encompasses the Company's processes, assessments, calculations and supporting documentation.
- Managed teams in the conduct of Sarbanes Oxley Section 404 readiness testing for international advertising, marketing, and communication services companies in 2004 and 2005.

Education

- Bachelor of Science in Business Administration, Accounting and Finance emphasis, University of Nevada, Las Vegas

Certifications and Memberships

- Society of Depreciation Professionals
- Past President and other leadership positions for the Society of Depreciation Professionals

Other Professional Activities

- Review and content contributor for Hahne-Aliff "Accounting for Public Utilities", Chapter 6 Public Utility Depreciation during tenure at Deloitte
- Former Board member as well as Treasurer, Secretary, Vice President, and President of the Society of Depreciation Professionals
- Presenter at AGA/EEI Accounting Committee Meetings
- Taught client requested Depreciation Basics

REBECCA RICHARDS, CDP

SENIOR CONSULTANT, ALLIANCE CONSULTING GROUP

Profile

- 20 years of experience in utility property accounting, depreciation, and corporate finance.
- Coordinated several depreciation studies for all types of utilities including electric, gas, water, and steam heating.
- Certified Depreciation Professional (CDP) as recognized by the Society of Depreciation Professionals.

Professional Experience

- 2015-present
  - Senior Consultant - Alliance Consulting Group, Plano, TX
    Senior Consultant involved in all aspects of depreciation studies. Perform depreciation studies for electric, gas, communication, water and wastewater utility clients. Provide support during rate case litigation including drafting study narratives and responding to interrogatories.

- 2006-2015
  - Team Lead Property Accounting - We Energies, Milwaukee, WI
    Managed all fixed asset internal and external reporting and property accounting functions in compliance with state and federal regulatory requirements. Established and maintained the Company's capitalization and depreciation policies. Initiated and oversaw all process improvement initiatives related to fixed asset finance systems and processes. Coordinated depreciation studies and supported rate case and regulatory proceedings. Vast working knowledge of fixed asset and finance systems including SAP, UI, and PowerPlant.

- 1995-2006
  - Operations Manager - Courtyard by Marriott, Brookfield, WI
    Hired, trained, and developed all front desk associates and maintained Marriott's high quality customer service standards.

Education

- Bachelor of Science in Accounting, Marquette University, Milwaukee, WI
- Associate's degree in accounting, Milwaukee Area Technical College, Milwaukee, WI

Certification

- Certified Depreciation Professional, since 2020

Memberships

- Society of Depreciation Professionals
- Society of Depreciation Professionals, Associate Trainer, 2024 to present
- Society of Depreciation Professionals, Vice President, 2023
- Society of Depreciation Professionals, President 2024
- Society of Depreciation Professionals, Past President, 2025

Rich Bennett, MBA, CDP

Senior Consultant, Alliance Consulting Group

Profile

- Over 40 years of experience in utility fixed asset and regulatory consulting, including depreciation studies, accounting, and financial analysis.
- Recognized for expertise in utility accounting, depreciation, ratemaking, forecasting, and regulatory support across electric, gas, and water utilities.
- Proven leader with strong managerial, team building, and communication skills; adept at managing cross-functional teams and delivering presentations to diverse audiences.
- Certified Depreciation Professional (CDP) and active Board Member and Secretary of the Society of Depreciation Professionals.

Relevant Experience and Accomplishments

- Depreciation and Asset Accounting
  - Managed and sponsored book depreciation studies and regulatory filings for Southern California Edison (SCE), including CPUC and FERC rate cases.
  - Led SCE Rate Base and Depreciation Accounting and Analytics, responsible for rate base forecasts and regulatory support.
  - Directed SCE's ERP Fixed Asset Sub-Team, overseeing SAP ERP and PowerPlan solution implementation.
  - Functional Lead for multiple Depreciation Study Module and Lease Module implementations at PowerPlan, Inc. and client utilities.
  - Provided forensic accounting and FERC 898 compliance support for various utility clients.
  - Delivered regulatory and analytical support for general rate cases and regulatory proceedings at SCE, PG&E, and other major utilities.
- System/Process Reengineering
  - Managed regulatory analysis, accounting analytics, and plant accounting groups at SCE, overseeing monthly work order accounting, depreciation, AFUDC entries, and special projects.
  - Led teams in the design, testing, and implementation of accounting upgrades and merger projects, including SAP ERP and PowerPlan integrations.
  - Championed process improvements in financial analytics, budgeting, and quarterly business reviews for SCE's Transmission and Distribution Business Unit.

Employment History

- 2025-Present
  - Senior Consultant Alliance Consulting Group, Plano, TX
    Recent: Regulatory support, depreciation studies, and asset accounting for major utility clients.
- 2023-2025
  - Senior Manager Utility Consulting Group Solutions (UCG Solutions)
    Provided regulatory support and forensic accounting for utility clients.
- 2016-2023
  - Senior Solution Architect PowerPlan, Inc.
    Led solution design and implementation for Rate Case & ROE Management Suite, Lease Accounting, and Depreciation Study Modules.
- 1983-2015
  - Manager—Rate Base and Depreciation Accounting, Regulatory Analysis and Plant Accounting Southern California Edison (SCE)
    Directed accounting, analytics, and regulatory support for multiple rate cases and filings.
- Various Dates
  - Consulted for Pacific Gas & Electric (PG&E), Portland General Electric, San Jose Water Group, Sempra Energy, and others on regulatory support, depreciation studies, and accounting upgrades.

Education

- MBA, University of La Verne
- B.S., Business (Management Science and Production), California State Polytechnic University, Pomona
- Completed advanced courses in depreciation, utility accounting, and regulatory topics through Depreciation Programs, Inc., EEI/AGA, and the Society of Depreciation Professionals.

Certification

- Certified Depreciation Professional (CDP), Society of Depreciation Professionals

Honors and Awards

- Secretary and Board Member, Society of Depreciation Professionals
- Instructor for SDP classes in Life Analysis, Artificial Intelligence, and Depreciation Study preparation

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Nevada	Federal Energy Regulatory Commission	ER26-3479	DesertLink, LLC	2026	Electric Depreciation Study
Indiana	Federal Energy Regulatory Commission	ER26-2758	Republic Transmission, LLC	2026	Electric Depreciation Study
Missouri, Kansas, Arkansas, Oklahoma	Federal Energy Regulatory Commission	ER26-3348-000	Liberty TFR	2026	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-37969	Cleco	2026	Electric Depreciation Study
Alabama	Alabama Public Service Commission	33525	Alalabama Water Utilities	2026	Water/Wastewater Depreciation Study
Colorado	Colorado Public Utilities Commission	25AL-0538G	Public Service of Colorado	2026	Gas Depreciation Study
California	California Public Utilities Commission	A.26-06-xxx	Southern California Gas	2026	Gas Depreciation Study
California	California Public Utilities Commission	A.26-06-xxx	San Diego Gas and Electric	2026	Electric & Gas Depreciation Study
Texas	Public Utility Commission of Texas	59742	Rayburn Country Electric Cooperative, Inc.	2026	Electric Transmission Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	5-DU-104	WEPCO & WG	2026	Electric, Gas, Steam and Common Depreciation Studies
Texas	Railroad Commission of Texas	OS-26-00031317	SiEnergy	2026	Gas Depreciation Study
Texas	Public Utility Commission of Texas	59756	Pedermales Electric Coop	2026	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	26-020-U	Liberty Arkansas	2026	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	26-166 (D)	Allete Minnesota Power	2026	Electric Depreciation Study
Kansas	Kansas Corporation Commission	26-ATMG-026-RTS	Atmos Kansas	2026	Gas Depreciation Study
Multi State	FERC	ER26-827-000	American Transmission Company	2026	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR-25110627	South Jersey Gas	2025	Gas Depreciation Study
Texas	Public Utility Commission of Texas	59245	Lone Star Transmission	2026	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD25-000028	Summit Utilities Oklahoma	2025	Natural Gas Depreciation Study
Canada	Ontario Energy Board	EB-2025-0252	Alectra Utilities Corporation	2025	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	25-00079-UT	Southwestern Public Service Company	2025	Electric Depreciation Study
Multi State	FERC	ER26-408-000	Entergy Services	2025	Electric Depreciation Study
Multi State	FERC	ER26-263-000	Entergy Services	2025	Electric Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Colorado	Colorado Public Utilities Commission	25AL-0494E	Xcel PSCO Electric	2025	Electric Depreciation Study
Texas	Public Utility Commission of Texas	58964	Texas New Mexico Power	2025	Electric Depreciation Rate Study
Rhode Island	State of Rhode Island Utilities Commission	25-30-WW	Veolia Rhode Island Water	2025	Water Depreciation Study
Missouri	Public Service Commission of State of Missouri	ER-2024-0261	Liberty Empire Electric Missouri	2025	Electric Generation Accrual Rates
New Jersey	New Jersey Board of Public Utilities	WR25060372	Middlesex Water	2025	Water and Waste Water Depreciation Study
Texas	Public Utility Commission of Texas	58306	Oncor	2025	Depreciation Study
Mississippi	Mississippi Public Service Commission	2025-US-59	Atmos Energy	2025	Gas Depreciation Study
Delaware & New Jersey	FERC	ER25-6061	Silver Run Electric, LLC	2025	Electric Depreciation Study
Nevada & Idaho	FERC	ER25-2025	Great Basin Transmission, LLC	2025	Electric Depreciation Study
Texas	Public Utility Commission of Texas	Docket 57994	Sharyland Utilities	2025	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	25A-0165G	Public Service Company of Colorado	2025	Gas Depreciation Study
Texas	Public Utility Commission of Texas	57467	Cross Texas Transmission	2025	Electric Depreciation Study
Delaware	Delaware Public Service Commission	Docket 25-0037	Veolia Delaware	2024	Water Depreciation Study
Texas	Public Utility Commission of Texas	57299	Wind Energy Transmission Texas	2024	Wind Depreciation Rate Study
Tennessee	Tennessee Public Utility Commission	24-00085	Piedmont Natural Gas	2024	Gas Depreciation Study
Texas	Railroad Commission of Texas	No. 00019196	Atmos Mid-Tex	2024	Gas Depreciation Study
California	FERC	ER25-270-000	San Diego Gas and Electric	2024	TO6
Texas	Railroad Commission of Texas	No. 00018879	Atmos West Texas	2024	Natural Gas Depreciation Study
South Carolina	South Carolina Public Service Commission	2024-179-G	Piedmont Natural Gas	2024	Natural Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-21542	Upper Michigan Energy Resources Corporation	2024	Reciprocating Internal Combustion Engine (RICE) Units
California	California Public Utilities Commission	A2407003	California Water Service	2024	Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-24-017	Matanuska Electric Coop	2024	Electric Depreciation Study
New Mexico	Public Service of New Mexico	24-00089-UT	PNM Resources	2024	Electric Technical Update

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	17816	West Texas Gas	2024	Gas Depreciation Study
Texas	Public Utility Commission of Texas	56665	Texas Water Utilities	2024	Water Depreciation Study
Multi-state	FERC	EL24-60-000	Viridon Mid-Atlantic LLC	2024	Electric Depreciation Study
Multi-state	FERC	EL24-66-000	Viridon Southwest LLC	2024	Electric Depreciation Study
Multi-state	FERC	EL24-67-000	Viridon New York Inc.	2024	Electric Depreciation Study
Multi-state	FERC	EL24-69-000	Viridon Midcontinent LLC	2024	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	G-9, Sub 837	Piedmont Natural Gas	2024	Gas Depreciation Study
Mississippi	FERC	ER-24-1652-000	Mississippi Power Company	2024	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR24020158	Elizabethtown Gas Company	2024	Gas Depreciation Study
Texas New Mexico	FERC	ER24-1431-000	Southwestern Public Service Company	2024	Electric Technical Update
Missouri	Missouri Public Service Commission	WR-2024-0104	Liberty Utilities Missouri Water	2024	Water Depreciation Study
Missouri	Missouri Public Service Commission	SR-2024-0105	Liberty Utilities Missouri Waste Water	2024	Waste Water Depreciation Study
Texas	Public Utility Commission of Texas	56211	CenterPoint	2024	Electric Depreciation Study
California	California Public Utilities Commission	A.24-01-001	San Jose Water Co	2024	Water/Wastewater Depreciation Study
Missouri	Missouri Public Service Commission	GR-2024-0106	Liberty Utilities Mid States Gas	2024	Gas Depreciation Study
Pennsylvania	Pennsylvania Public Utility Commission	R-2024-3045193	Veolia Pennsylvania	2024	WasteWater Depreciation Study
Pennsylvania	Pennsylvania Public Utility Commission	R-2024-3045192	Veolia Pennsylvania	2024	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	23-079-U	Summit Utilities Arkansas	2024	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	23A-0632G	Atmos Energy	2023	Gas Clean Heat Plan
Illinois	Illinois Commerce Commission	24-0043	Liberty Mid States Gas-Illinois	2023	Gas Depreciation Study
Oklahoma	Oklahoma Corporation Commission	2023-00087	Oklahoma Gas & Electric	2023	Electric Depreciation Study
Michigan	Michigan Public Service Commission	21513	Upper Peninsula Power Company	2023	Electric Depreciation Study
Texas	Public Utility Commission of Texas	55867	Lower Colorado River Authority	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	Case No. OS-23-00015513	CenterPoint Texas Gas	2023	Gas Depreciation Study
Nevada	Public Utility Commission of Nevada	23-090-12	Southwest Gas	2023	Gas Depreciation Study - Nevada Division

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Louisiana	Public Service Commission of Louisiana	36959	Entergy Louisiana	2023	Electric Depreciation Study
Texas	Railroad Commission of Texas	13758	Atmos Energy - APT	2023	Gas Depreciation Study
Florida	Florida Public Service Commission	20230023	Peoples Gas System	2023	Gas Depreciation Study
Texas	Public Utility Commission of Texas	54565	Central States Water Resources (CSWR Texas)	2023	Water Depreciation Study
New York	New York State Public Service Commission	23-W-0111	Veolia New York	2023	Water Depreciation Study
Arkansas	Arkansas Public Service Commission	22-085-U	Empire District Electric Company	2023	Electric Depreciation Study
Texas	Public Utility Commission of Texas	54634	Southwestern Public Service Company	2023	Electric Technical Update
Louisiana	Louisiana Public Service Commission	U-36923	Cleco	2023	Electric Depreciation study
Arkansas	Arkansas Public Service Commission	22-085-U	Liberty Empire Electric Arkansas	2023	Electric Depreciation Study
Florida	Florida Public Service Commission	20220219	People Gas System	2022	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-21329	Michigan Gas Utilities Corporation	2022	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00270-UT	Public Service of New Mexico	2022	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	22-00286-UT	Southwestern Public Service Company	2022	Electric Technical Update
Michigan	Michigan Public Service Commission	U-21294	SEMCO Gas	2022	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	22-064-U	Liberty Pine Bluff Water	2022	Water Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0348G	Atmos Energy	2022	Gas Depreciation Study
New York	FERC	ER22-2581-000	New York Power Authority	2022	Electric Transmission and General Depreciation Study
South Carolina	South Carolina Public Service Commission	2022-89-G	Piedmont Natural Gas	2022	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-22-034	Chugach Electric Association	2022	Electric Depreciation Study
Georgia	Georgia Public Service Commission	44280	Georgia Power Company	2022	Electric Depreciation Study
Texas	Public Utility Commission of Texas	53719	Entergy Texas	2022	Electric Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
California	California Public Utilities Commission	A22-005-016	San Diego Gas and Electric	2022	Electric Gas and Common Depreciation Study
California	California Public Utilities Commission	A22-005-015	Southern California Gas	2022	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	22AL-0046G	Public Service of Colorado	2022	Gas Alternatives to Climate Goals
Texas	Public Utility Commission of Texas	53601	Oncor Electric Delivery	2022	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR2222040253	South Jersey Gas	2022	Gas Depreciation Study
Oklahoma	Corporation Commission of Oklahoma	PUD 202100163	Empire District Electric Company	2022	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-21176	Consumers Gas	2021	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR21121254	Elizabethtown Natural Gas	2021	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	TA116-118, TA115-97, TA160-37 and TA110-290	Fairbanks Water and Wastewater	2021	Water and Waste Water Depreciation Study
Alaska	Regulatory Commission of Alaska	U-21-025	Golden Valley Electric Association	2021	Electric Depreciation Study
Colorado	Public Utilities Commission of Colorado	21AL-0317E	Public Service of Colorado	2021	Electric and Common Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	5-DU-103	WE Energies	2021	Electric and Gas Depreciation Study
Kentucky	Public Service Commission of Kentucky	2021-00214	Atmos Kentucky	2021	Gas Depreciation Study
Missouri	Missouri Public Service Commission	ER-2021-0312	Empire District Electric Company	2021	Electric Depreciation Study
Louisiana	Louisiana Public Service Commission	U-35951	Atmos Louisiana	2021	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015-D-21-229	Allete Minnesota Power	2021	Intangible, Transmission, Distribution, and General Depreciation Study
Michigan	Michigan Public Service Commission	U-20849	Consumers Energy	2021	Electric and Common Depreciation Study
Texas	Public Utility Commission of Texas	51802	Southwestern Public Service Company	2021	Electric Technical Update
MultiState	FERC	RP21-441-000	Florida Gas Transmission	2021	Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	20-00238-UT	Southwestern Public Service Company	2021	Electric Technical Update

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
MultiState	FERC	ER21-709-000	American Transmission Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	51611	Sharyland Utilities	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	51536	Brownsville Public Utilities Board	2020	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	WR20110729	Suez Water New Jersey	2020	Water and Waste Water Depreciation Study
Idaho	Idaho Public Service Commission	SUZ-W-20-02	Suez Water Idaho	2020	Water Depreciation Study
Texas	Public Utility Commission of Texas	50944	Monarch Utilities	2020	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-20844	Consumers Energy/DTE Electric	2020	Ludington Pumped Storage Depreciation Study
Tennessee	Tennessee Public Utility Commission	20-00086	Piedmont Natural Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	OS-00005136	CoServ Gas	2020	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10988	EPCOR Gas Texas	2020	Gas Depreciation Study
Florida	Florida Public Service Commission	20200166-GU	People Gas System	2020	Gas Depreciation Study
Mississippi	Federal Energy Regulatory Commission	ER20-1660-000	Mississippi Power Company	2020	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50557	Corix Utilities	2020	Water and Waste Water Depreciation Study
Georgia	Georgia Public Service Commission	42959	Liberty Utilities Peach State Natural Gas	2020	Gas Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR20030243	South Jersey Gas	2020	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	20AL-0049G	Public Service of Colorado	2020	Gas Depreciation Study
New York	Federal Energy Regulatory Commission	ER20-716-000	LS Power Grid New York, Corp.	2019	Electric Transmission Depreciation Study
Mississippi	Mississippi Public Service Commission	2019-UN-219	Mississippi Power Company	2019	Electric Depreciation Study
Texas	Public Utility Commission of Texas	50288	Kerrville Public Utility District	2019	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10920	CenterPoint Gas	2019	Gas Depreciation Study and Propane Air Study
Texas, New Mexico	Federal Energy Regulatory Commission	ER20-277-000	Southwestern Public Service Company	2019	Electric Production and General Plant Depreciation Study
Alaska	Regulatory Commission of Alaska	U-19-086	Alaska Electric Light and Power	2019	Electric Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Delaware	Delaware Public Service Commission	19-0615	Suez Water Delaware	2019	Water Depreciation Study
Texas	Public Utility Commission of Texas	49831	Southwestern Public Service Company	2019	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	19-00170-UT	Southwestern Public Service Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42516	Georgia Power Company	2019	Electric Depreciation Study
Georgia	Georgia Public Service Commission	42315	Atlanta Gas Light	2019	Gas Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-19-0055	Southwest Gas Corporation	2019	Gas Removal Cost Study
New Hampshire	New Hampshire Public Service Commission	DE 19-064	Liberty Utilities	2019	Electric Distribution and General
New Jersey	New Jersey Board of Public Utilities	GR19040486	Elizabethtown Natural Gas	2019	Gas Depreciation Study
Texas	Public Utility Commission of Texas	49421	CenterPoint Houston Electric LLC	2019	Electric Depreciation Study
North Carolina	North Carolina Utilities Commission	Docket No. G-9, Sub 743	Piedmont Natural Gas	2019	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-121	Municipal Power and Light City of Anchorage	2018	Electric Depreciation Study
Various	FERC	RP19-352-000	Sea Robin	2018	Gas Depreciation Study
Texas New Mexico	Federal Energy Regulatory Commission	ER19-404-000	Southwestern Public Service Company	2018	Electric Transmission Depreciation Study
California	Federal Energy Regulatory Commission	ER19-221-000	San Diego Gas and Electric	2018	Electric Transmission Depreciation Study
Kentucky	Kentucky Public Service Commission	2018-00281	Atmos Kentucky	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-18-054	Matanuska Electric Coop	2018	Electric Generation Depreciation Study
California	California Public Utilities Commission	A17-10-007	San Diego Gas and Electric	2018	Electric and Gas Depreciation Study
Texas	Public Utility Commission of Texas	48401	Texas New Mexico Power	2018	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	18-05031	Southwest Gas	2018	Gas Depreciation Study
Texas	Public Utility Commission of Texas	48231	Oncor Electric Delivery	2018	Depreciation Rates
Texas	Public Utility Commission of Texas	48371	Entergy Texas	2018	Electric Depreciation Study
Kansas	Kansas Corporation Commission	18-KCPE-480-RTS	Kansas City Power and Light	2018	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	18-027-U	Liberty Pine Bluff Water	2018	Water Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kentucky	Kentucky Public Service Commission	2017-00349	Atmos KY	2018	Gas Depreciation Rates
Tennessee	Tennessee Public Utility Commission	18-00017	Chattanooga Gas	2018	Gas Depreciation Study
Texas	Railroad Commission of Texas	10679	Si Energy	2018	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-104	Anchorage Water and Wastewater	2017	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-18488	Michigan Gas Utilities Corporation	2017	Gas Depreciation Study
Texas	Railroad Commission of Texas	10669	CenterPoint South Texas	2017	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	17-061-U	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Kansas	Kansas Corporation Commission	18-EPDE-184-PRE	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Oklahoma	Oklahoma Corporation Commission	PUD 201700471	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Missouri	Missouri Public Service Commission	EO-2018-0092	Empire District Electric Company	2017	Depreciation Rates for New Wind Generation
Michigan	Michigan Public Service Commission	U-18457	Upper Peninsula Power Company	2017	Electric Depreciation Study
Florida	Florida Public Service Commission	20170179-GU	Florida City Gas	2017	Gas Depreciation Study
Michigan	FERC	ER18-56-000	Consumers Energy	2017	Electric Depreciation Study
Missouri	Missouri Public Service Commission	GR-2018-0013	Liberty Utilities	2017	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18452	SEMCO	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	47527	Southwestern Public Service Company	2017	Electric Production Depreciation Study
MultiState	FERC	ER17-1664	American Transmission Company	2017	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-17-008	Municipal Power and Light City of Anchorage	2017	Generating Unit Depreciation Study
Mississippi	Mississippi Public Service Commission	2017-UN-041	Atmos Energy	2017	Gas Depreciation Study
Texas	Public Utility Commission of Texas	46957	Oncor Electric Delivery	2017	Electric Depreciation Study
Oklahoma	Oklahoma Corporation Commission	PUD 201700078	CenterPoint Oklahoma	2017	Gas Depreciation Study
New York	FERC	ER17-1010-000	New York Power Authority	2017	Electric Depreciation Study
Texas	Railroad Commission of Texas	GUD 10580	Atmos Pipeline Texas	2017	Gas Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	GUD 10567	CenterPoint Texas	2016	Gas Depreciation Study
MultiState	FERC	ER17-191-000	American Transmission Company	2016	Electric Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR16090826	Elizabethtown Natural Gas	2016	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-18195	Consumers Energy/DTE Electric	2016	Ludington Pumped Storage Depreciation Study
Alabama	FERC	ER16-2313-000	SEGCO	2016	Electric Depreciation Study
Alabama	FERC	ER16-2312-000	Alabama Power Company	2016	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-18127	Consumers Energy	2016	Natural Gas Depreciation Study
Mississippi	Mississippi Public Service Commission	2016 UN 267	Willmut Natural Gas	2016	Natural Gas Depreciation Study
Iowa	Iowa Utilities Board	RPU-2016-0003	Liberty-Iowa	2016	Natural Gas Depreciation Study
Illinois	Illinois Commerce Commission	GRM #16-208	Liberty-Illinois	2016	Natural Gas Depreciation Study
Kentucky	FERC	RP16-097-000	KOT	2016	Natural Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-16-067	Alaska Electric Light and Power	2016	Generating Unit Depreciation Study
Florida	Florida Public Service Commission	160170-EI	Gulf Power	2016	Electric Depreciation Study
California	California Public Utilities Commission	A 16-07-002	California American Water	2016	Water and Waste Water Depreciation Study
Arizona	Arizona Corporation Commission	G-01551A-16-0107	Southwest Gas	2016	Gas Depreciation Study
Texas	Public Utility Commission of Texas	45414	Sharyland	2016	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	16A-0231E	Public Service Company of Colorado	2016	Electric Depreciation Study
Multi-State NE US	FERC	16-453-000	Northeast Transmission Development, LLC	2015	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	15-098-U	CenterPoint Arkansas	2015	Gas Depreciation Study and Cost of Removal Study
New Mexico	New Mexico Public Regulation Commission	15-00296-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Atmos Energy Corporation	Tennessee Regulatory Authority	14-00146	Atmos Tennessee	2015	Natural Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00261-UT	Public Service Company of New Mexico	2015	Electric Depreciation Study
Hawaii	NA	NA	Hawaii American Water	2015	Water/Wastewater Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Kansas	Kansas Corporation Commission	16-ATMG-079-RTS	Atmos Kansas	2015	Gas Depreciation Study
Texas	Public Utility Commission of Texas	44704	Entergy Texas	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-15-089	Fairbanks Water and Wastewater	2015	Water and Waste Water Depreciation Study
Arkansas	Arkansas Public Service Commission	15-031-U	Source Gas Arkansas	2015	Underground Storage Gas Depreciation Study
New Mexico	New Mexico Public Regulation Commission	15-00139-UT	Southwestern Public Service Company	2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	44746	Wind Energy Transmission Texas	2015	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	15-AL-0299G	Atmos Colorado	2015	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	15-011-U	Source Gas Arkansas	2015	Gas Depreciation Study
Texas	Railroad Commission of Texas	GUD 10432	CenterPoint- Texas Coast Division	2015	Gas Depreciation Study
Kansas	Kansas Corporation Commission	15-KCPE-116-RTS	Kansas City Power and Light	2015	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-120	Alaska Electric Light and Power	2014-2015	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43950	Cross Texas Transmission	2014	Electric Depreciation Study
New Mexico	New Mexico Public Regulation Commission	14-00332-UT	Public Service of New Mexico	2014	Electric Depreciation Study
Texas	Public Utility Commission of Texas	43695	Xcel Energy	2014	Electric Depreciation Study
Multi State – SE US	FERC	RP15-101	Florida Gas Transmission	2014	Gas Transmission Depreciation Study
California	California Public Utilities Commission	A.14-07-006	Golden State Water	2014	Water and Waste Water Depreciation Study
Michigan	Michigan Public Service Commission	U-17653	Consumers Energy Company	2014	Electric and Common Depreciation Study
Alabama	Alabama Public Service Commission	U-5115	Mobile Gas	2014	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	14AL-0660E	Public Service of Colorado	2014	Electric Depreciation Study
Wisconsin	Wisconsin	05-DU-102	WE Energies	2014	Electric, Gas, Steam and Common Depreciation Studies
Texas	Public Utility Commission of Texas	42469	Lone Star Transmission	2014	Electric Depreciation Study
Nebraska	Nebraska Public Service Commission	NG-0079	Source Gas Nebraska	2014	Gas Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-14-055	TDX North Slope Generating	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-054	Sand Point Generating LLC	2014	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-14-045	Matanuska Electric Coop	2014	Electric Generation Depreciation Study
Texas, New Mexico	Public Utility Commission of Texas	42004	Southwestern Public Service Company	2013-2014	Electric Production, Transmission, Distribution and General Plant Depreciation Study
New Jersey	New Jersey Board of Public Utilities	GR13111137	South Jersey Gas	2013	Gas Depreciation Study
Various	FERC	RP14-247-000	Sea Robin	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-078-U	Arkansas Oklahoma Gas	2013	Gas Depreciation Study
Arkansas	Arkansas Public Service Commission	13-079-U	Source Gas Arkansas	2013	Gas Depreciation Study
California	California Public Utilities Commission	Proceeding No.: A.13-11-003	Southern California Edison	2013	Electric Depreciation Study
North Carolina/South Carolina	FERC	ER13-1313	Progress Energy Carolina	2013	Electric Depreciation Study
Wisconsin	Public Service Commission of Wisconsin	4220-DU-108	Northern States Power Company - Wisconsin	2013	Electric, Gas and Common Transmission, Distribution and General
Texas	Public Utility Commission of Texas	41474	Sharyland	2013	Electric Depreciation Study
Kentucky	Kentucky Public Service Commission	2013-00148	Atmos Energy Corporation	2013	Gas Depreciation Study
Minnesota	Minnesota Public Utilities Commission	13-252	Allete Minnesota Power	2013	Electric Depreciation Study
New Hampshire	New Hampshire Public Service Commission	DE 13-063	Liberty Utilities	2013	Electric Distribution and General
Texas	Railroad Commission of Texas	10235	West Texas Gas	2013	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-154	Alaska Telephone Company	2012	Telecommunications Utility
New Mexico	New Mexico Public Regulation Commission	12-00350-UT	Southwestern Public Service Company	2012	Electric Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1269ST	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study
Colorado	Colorado Public Utilities Commission	12AL-1268G	Public Service Company of Colorado	2012	Gas and Steam Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Alaska	Regulatory Commission of Alaska	U-12-149	Municipal Power and Light City of Anchorage	2012	Electric Depreciation Study
Texas	Public Utility Commission of Texas	40824	Xcel Energy	2012	Electric Depreciation Study
South Carolina	Public Service Commission of South Carolina	Docket 2012-384-E	Progress Energy Carolina	2012	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-12-141	Interior Telephone Company	2012	Telecommunications Utility
Michigan	Michigan Public Service Commission	U-17104	Michigan Gas Utilities Corporation	2012	Gas Depreciation Study
North Carolina	North Carolina Utilities Commission	E-2 Sub 1025	Progress Energy Carolina	2012	Electric Depreciation Study
Texas	Public Utility Commission of Texas	40606	Wind Energy Transmission Texas	2012	Electric Depreciation Study
Texas	Public Utility Commission of Texas	40604	Cross Texas Transmission	2012	Electric Depreciation Study
Minnesota	Minnesota Public Utilities Commission	12-858	Northern States Power Company - Minnesota	2012	Electric, Gas and Common Transmission, Distribution and General
Texas	Railroad Commission of Texas	10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10174	Atmos West Texas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10182	CenterPoint Beaumont/ East Texas	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-KCPE-764-RTS	Kansas City Power and Light	2012	Electric Depreciation Study
Nevada	Public Utility Commission of Nevada	12-04005	Southwest Gas	2012	Gas Depreciation Study
Texas	Railroad Commission of Texas	10147, 10170	Atmos Mid-Tex	2012	Gas Depreciation Study
Kansas	Kansas Corporation Commission	12-ATMG-564-RTS	Atmos Kansas	2012	Gas Depreciation Study
Texas	Public Utility Commission of Texas	40020	Lone Star Transmission	2012	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-16938	Consumers Energy Company	2011	Gas Depreciation Study
Colorado	Public Utilities Commission of Colorado	11AL-947E	Public Service of Colorado	2011	Electric Depreciation Study
Texas	Public Utility Commission of Texas	39896	Entergy Texas	2011	Electric Depreciation Study
MultiState	FERC	ER12-212	American Transmission Company	2011	Electric Depreciation Study
California	California Public Utilities Commission	A1011015	Southern California Edison	2011	Electric Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Mississippi	Mississippi Public Service Commission	2011-UN-184	Atmos Energy	2011	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-16536	Consumers Energy Company	2011	Wind Depreciation Rate Study
Texas	Public Utility Commission of Texas	38929	Oncor	2011	Electric Depreciation Study
Texas	Railroad Commission of Texas	10038	CenterPoint South TX	2010	Gas Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-070	Inside Passage Electric Cooperative	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	36633	City Public Service of San Antonio	2010	Electric Depreciation Study
Texas	Railroad Commission of Texas	10000	Atmos Pipeline Texas	2010	Gas Depreciation Study
Multi State – SE US	FERC	RP10-21-000	Florida Gas Transmission	2010	Gas Depreciation Study
Maine/ New Hampshire	FERC	10-896	Granite State Gas Transmission	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38480	Texas New Mexico Power	2010	Electric Depreciation Study
Texas	Public Utility Commission of Texas	38339	CenterPoint Electric	2010	Electric Depreciation Study
Texas	Railroad Commission of Texas	10041	Atmos Amarillo	2010	Gas Depreciation Study
Georgia	Georgia Public Service Commission	31647	Atlanta Gas Light	2010	Gas Depreciation Study
Texas	Public Utility Commission of Texas	38147	Southwestern Public Service	2010	Electric Technical Update
Alaska	Regulatory Commission of Alaska	U-09-015	Alaska Electric Light and Power	2009-2010	Electric Depreciation Study
Alaska	Regulatory Commission of Alaska	U-10-043	Utility Services of Alaska	2009-2010	Water Depreciation Study
Michigan	Michigan Public Service Commission	U-16055	Consumers Energy/DTE Energy	2009-2010	Ludington Pumped Storage Depreciation Study
Michigan	Michigan Public Service Commission	U-16054	Consumers Energy	2009-2010	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15963	Michigan Gas Utilities Corporation	2009	Gas Depreciation Study
Michigan	Michigan Public Service Commission	U-15989	Upper Peninsula Power Company	2009	Electric Depreciation Study
Texas	Railroad Commission of Texas	9869	Atmos Energy	2009	Shared Services Depreciation Study
Mississippi	Mississippi Public Service Commission	09-UN-334	CenterPoint Energy Mississippi	2009	Gas Depreciation Study
Texas	Railroad Commission of Texas	9902	CenterPoint Energy Houston	2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	09AL-299E	Public Service Company of Colorado	2009	Electric Depreciation Study

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Louisiana	Louisiana Public Service Commission	U-30689	Cleco	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35763	Southwestern Public Service Company	2008	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Wisconsin	Wisconsin	05-DU-101	WE Energies	2008	Electric, Gas, Steam and Common Depreciation Studies
North Dakota	North Dakota Public Service Commission	PU-07-776	Northern States Power Company - Minnesota	2008	Net Salvage
New Mexico	New Mexico Public Regulation Commission	07-00319-UT	Southwestern Public Service Company	2008	Testimony – Depreciation
Multiple States	Railroad Commission of Texas	9762	Atmos Energy	2007-2008	Shared Services Depreciation Study
Minnesota	Minnesota Public Utilities Commission	E015/D-08-422	Minnesota Power	2007-2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	35717	Oncor	2008	Electric Depreciation Study
Texas	Public Utility Commission of Texas	34040	Oncor	2007	Electric Depreciation Study
Michigan	Michigan Public Service Commission	U-15629	Consumers Energy	2006-2009	Gas Depreciation Study
Colorado	Colorado Public Utilities Commission	06-234-EG	Public Service Company of Colorado	2006	Electric Depreciation Study
Arkansas	Arkansas Public Service Commission	06-161-U	CenterPoint Energy – Arkla Gas	2006	Gas Distribution Depreciation Study and Removal Cost Study
Texas, New Mexico	Public Utility Commission of Texas	32766	Southwestern Public Service Company	2005-2006	Electric Production, Transmission, Distribution and General Plant Depreciation Study
Texas	Railroad Commission of Texas	9670/9676	Atmos Energy Corp	2005-2006	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9400	TXU Gas	2003-2004	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9313	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Railroad Commission of Texas	9225	TXU Gas	2002	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	24060	TXU	2001	Line Losses
Texas	Public Utility Commission of Texas	23640	TXU	2001	Line Losses
Texas	Railroad Commission of Texas	9145-9148	TXU Gas	2000-2001	Gas Distribution Depreciation Study
Texas	Public Utility Commission of Texas	22350	TXU	2000-2001	Electric Depreciation Study, Unbundling

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Alliance Consulting Group Testimony Appearances

Asset Location	Commission	Docket (If Applicable	Company	Year	Description
Texas	Railroad Commission of Texas	8976	TXU Pipeline	1999	Pipeline Depreciation Study
Texas	Public Utility Commission of Texas	20285	TXU	1999	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	18490	TXU	1998	Transition to Competition
Texas	Public Utility Commission of Texas	16650	TXU	1997	Customer Complaint
Texas	Public Utility Commission of Texas	15195	TXU	1996	Mining Company Depreciation Study
Texas	Public Utility Commission of Texas	12160	TXU	1993	Fuel Company Depreciation Study
Texas	Public Utility Commission of Texas	11735	TXU	1993	Electric Depreciation Study

DEPRECIATION AND AMORTIZATION EXPENSES SCHEDULE

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CHAPTER 2 APPENDIX 2-BB - TRANSMISSION AND DISTRIBUTION

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DEPRECIATION AND AMORTIZATION EXPENSES – HOSSM

1.0 INTRODUCTION

The purpose of this evidence is to describe Hydro One Sault Ste. Marie LP's (HOSSM) depreciation and amortization expenses for the 2027 to 2032 test years, and outline the methodology used to determine those amounts historically and for purposes of this Application.

1.1 HOSSM BACKGROUND

HOSSM operates as a separate regulated entity within the Hydro One group and maintains its own accounting and regulatory framework, which supports the use of distinct asset and depreciation treatments. Consistent with its standalone financial reporting under IFRS and established historical practices, HOSSM applies an asset-level depreciation approach that differs from HONI's group-based methodology under U.S. GAAP. These differences in accounting framework and underlying asset data support the continued use of separate depreciation methodologies and reporting for HOSSM within the current rate Application.

1.2 APPROACH TO 2027-2032 DEPRECIATION AND AMORTIZATION EXPENSES

A dedicated depreciation study was not undertaken specifically for HOSSM as part of the current Application. Although HOSSM is rebasing, it continues to do so under its own distinct revenue requirement rather than as part of HONI's consolidated framework. Given this continued regulatory separation, HOSSM's assets were not included in the depreciation study undertaken for HONI. Instead, depreciation rates and service lives have been maintained based on established legacy parameters, which remain appropriate for its standalone asset base. Maintaining these legacy assumptions ensures consistency with HOSSM's historical regulatory treatment and avoids introducing unsupported changes to depreciation in advance of any future consolidation, at which time a comprehensive, combined assessment of asset lives and depreciation rates would be more appropriate.

2.0 DEPRECIATION EXPENSE

Table 1 and 2, below, present each of the elements required to determine the proposed depreciation expenses for HOSSM's assets over the 2016 to 2032 period, which include the 2016 to 2025 historical period, the 2026[1] bridge year, and the 2027 to 2032 test years.

These elements include (a) Depreciation on Fixed Assets, (b) Capitalized Depreciation, (c) Asset Removal Costs, and (d) Losses/Gains on Asset Disposition. Each of these elements is discussed below.

Detailed depreciation schedules are filed at Attachments 1 and 2 to this exhibit.

[1] 2026 is provided on a forecast basis.

1

Table 1 - HOSSM Depreciation Expense Historical Actuals 2016-2022 ($M)[2]

	Historical Actuals																				
	2016			2017			2018			2019			2020			2021			2022		
Transmission	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**
Depreciation On Fixed Assets	9.3	N/A	N/A	9.1	N/A	N/A	8.9	N/A	N/A	8.4	N/A	N/A	8.3	N/A	N/A	8.3	N/A	N/A	8.6	N/A	N/A
Less Capitalized Depreciation	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A
Asset Removal Costs	0.0	N/A	N/A	0.0	N/A	N/A	0.2	N/A	N/A	0.1	N/A	N/A	0.2	N/A	N/A	0.4	N/A	N/A	0.4	N/A	N/A
Losses/(Gains) On Asset Disposition	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	(1.2)	N/A	N/A	(0.1)	N/A	N/A
Total	**9.3**	**9.8**	**(0.5)**	**9.1**	**N/A**	**N/A**	**9.1**	**N/A**	**N/A**	**8.5**	**N/A**	**N/A**	**8.4**	**N/A**	**N/A**	**7.6**	**N/A**	**N/A**	**8.9**	**N/A**	**N/A**

**Note: Depreciation expense includes amortization of intangible assets (captured in asset class 1610) and amortization of deferred revenue of capital contributions in aid of construction (captured in asset class 2440), as these amounts are not material.*
***Note: OEB-approved amounts are not applicable for HOSSM for 2017–2026, as the revenue requirement was established in 2016 and subject to deferred rebasing through 2026 (EB-2016-0050).*

[2] Figures presented in the tables may not sum to the totals shown due to rounding.

Table 2 - HOSSM Depreciation Expense Historical Actuals (2023-2025), Bridge and Test Years (2026-2032) ($M)[3]

	Historical Actuals									Bridge			Test Years							
	2023			2024			2025			2026			2027			2028	2029	2030	2031	2032
Transmission	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Actual***	**OEB-App.****	**Diff.**	**Fcst.***	**OEB-App.****	**Diff.**	**Fcst.***	**OEB-App.****	**Diff.**	**Fcst.***	**Fcst.***	**Fcst.***	**Fcst.***	**Fcst.***
Depreciation On Fixed Assets	8.7	N/A	N/A	9.0	N/A	N/A	9.0	N/A	N/A	11.0	N/A	N/A	12.1	N/A	N/A	12.9	13.9	14.9	15.2	15.9
Less Capitalized Depreciation	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0
Asset Removal Costs	0.0	N/A	N/A	0.4	N/A	N/A	2.6	N/A	N/A	1.5	N/A	N/A	1.0	N/A	N/A	1.4	0.9	0.7	0.7	0.7
Losses/(Gains) On Asset Disposition	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	N/A	N/A	0.0	0.0	0.0	0.0	0.0
Total	**8.7**	**N/A**	**N/A**	**9.5**	**N/A**	**N/A**	**11.7**	**N/A**	**N/A**	**12.5**	**N/A**	**N/A**	**13.0**	**N/A**	**N/A**	**14.3**	**14.7**	**15.5**	**15.9**	**16.6**

**Note: Depreciation expense includes amortization of intangible assets (captured in asset class 1610) and amortization of deferred revenue of capital contributions in aid of construction (captured in asset class 2440), as these amounts are not material.*
***Note: OEB-approved amounts are not applicable for HOSSM for 2017–2026, as the revenue requirement was established in 2016 and subject to deferred rebasing through 2026 (EB-2016-0050).*

[3] Figures presented in the tables may not sum to the totals shown due to rounding

2.1 DEPRECIATION ON FIXED ASSETS

HOSSM has historically employed the half-year rule in calculating its depreciation expense for in-service additions and has continued this practice for the test years. Upon consolidation, HOSSM will be incorporated into HONI's standard process, under which depreciation rates are periodically reviewed by an external, independent fixed asset actuary. Any resulting changes will be reflected for accounting purposes prospectively, consistent with their inclusion in electricity rates and subject to approval by the OEB.

For costs relating to common assets, which are not directly attributable to HOSSM, Hydro One has consistently applied the OEB-approved Shared Asset allocation methodology detailed in Exhibit C-03-01. Depreciation and amortization expenses are calculated for HOSSM based on asset allocations using the Shared Asset methodology.

The increase in 2028 depreciation expense on HOSSM fixed assets compared to 2027 is primarily attributable to a higher level of assets placed in service, resulting in a larger depreciable asset base.

2.2 CAPITALIZED DEPRECIATION

HOSSM does not currently have any existing or proposed capitalized depreciation to consider in this Application.

2.3 ASSET REMOVAL COSTS

Fixed asset removal costs are grouped with depreciation expense and are recorded on an "as incurred" basis. These consist of the costs associated with removing old assets, such as the costs of digging up old foundations or removing old equipment.

Asset removal costs are included as a component of HOSSM's depreciation expense because, in an income statement, components are either classified by their nature or by their function. To report expenses by function means to report them according to the activity for which the expenses were incurred. The income statement will report expenses according to the following functional classifications: cost of power; operations,

maintenance and administration; depreciation and amortization; and financing. This requires grouping similar expenses. Accordingly, asset removal costs are grouped with depreciation and amortization due to their similar characteristics.

Most fixed asset removal costs are labour and equipment costs, rather than costs for materials, and are driven by the nature and timing of work. System Renewal work, which is driven by asset needs and customer outcomes, drives most of these expenditures.

2.4 LOSSES/GAINS ON ASSET DISPOSITION

Losses/gains on asset disposition relate to the sale of assets. Losses/gains on asset disposition are based on historical actuals and are not forecasted for the bridge or test years. HOSSM has not historically recognized significant gains or losses as the company does not focus substantial efforts on selling assets as part of its normal course of business.

DEPRECIATION AND AMORTIZATION EXPENSES SCHEDULE - HOSSM

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CHAPTER 2 APPENDIX 2-BB AND 2-C – HOSSM

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CORPORATE INCOME TAXES – TRANSMISSION AND DISTRIBUTION

1.0 INTRODUCTION

This Exhibit explains how Hydro One calculates its income tax expenses for the purposes of rate recovery (Regulatory Taxes) and is organized as follows:

- Section 2.0 provides an overview of tax;
- Section 3.0 provides a general overview of Regulatory Taxes as a component of revenue requirement;
- Section 4.0 details the applicable income tax rates used in determining Regulatory Taxes;
- Section 5.0 explains the different bases for computation of accounting and taxable income;
- Section 6.0 addresses the general adjustments made in computing taxable income and categorizes the types of adjustments commonly observed;
- Section 7.0 discusses the tax treatment of regulatory assets and regulatory liabilities;
- Section 8.0 reconciles regulatory net income and taxable income; and
- Section 9.0 summarizes steps taken by Hydro One to ensure data integrity.

Hydro One also provides detailed calculations of its income tax expenses for the historical, bridge and test years, along with supporting schedules and reconciliations, tax credit calculations, and other supporting schedules in Exhibit E-09-02, as well as a copy of its most recent tax return provided in Exhibit E-09-05.

The information provided in these schedules is responsive to Section 2.6.2.1 of the Distribution Filing Requirements and Section 2.8.10 of the Transmission Filing Requirements.

2.0 OVERVIEW OF TAX

Effective October 31, 2015, upon the Initial Public Offering (IPO) of its shares, Hydro One ceased to be tax exempt under the Income Tax Act (ITA) and was therefore required to exit the Payment in Lieu of Taxes (PILs) regime. Following the 2015 IPO, Hydro One exited the PILs regime and became fully subject to the federal and provincial corporate income tax system under the Income Tax Act.

3.0 REGULATORY TAXES – A COMPONENT OF REVENUE REQUIREMENT

Regulatory Taxes recoverable from ratepayers form part of the revenue requirement and are computed based on enacted tax legislation. Regulatory Taxes in a particular year represent the estimated current tax liability associated with regulatory net income before tax (NIBT) based on the applicable statutory tax rates for the year. Regulatory Taxes exclude future taxes arising from timing differences between when an amount is deductible or taxable for financial accounting and income tax purposes. Since regulatory taxes are included in the revenue requirement, fluctuations in regulatory tax amounts, whether higher or lower, are expected to result in corresponding changes in the revenue requirement, all else being equal.

The income tax expenses for which Hydro One seeks recovery in this proceeding exclude tax impacts in respect of items for which the OEB has explicitly prohibited recovery (i.e. donation credits), as well as in respect of items that do not relate to Hydro One's regulated Transmission and Distribution businesses, consistent with the stand-alone principle.[1]

4.0 REGULATORY TAXES – APPLICABLE INCOME TAX RATES (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the test years 2028 to 2032, as set out in Table 1 below, based on a federal rate of 15% and a provincial rate of 11.5%. Any variance between actual taxes payable and forecast taxes, as a result of changes in tax policy, tax legislation, income tax rates or capital cost allowance rates will be captured

[1] Chapter 2 Distribution Filing Requirements, Section 2.6.2, December 16, 2025

in a variance account for tax rate changes, Account 1592 – PILs and Taxes Variances, in accordance with Section 7.1 of the Electricity Distribution Rate (EDR) Handbook.

Table 1 - Combined Income Tax Rates

	Historical				Bridge	Test				
	2023	**2024**	**2025**	**2026-Forecast**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**
Federal Tax Rate (%)	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
Provincial Rate (%)	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**	**26.50**

5.0 CALCULATING TAXABLE INCOME

Regulatory Taxes are determined by applying the combined statutory tax rate to taxable income, which is derived from Hydro One's Transmission and Distribution regulated earnings before tax (EBT). Hydro One's EBT is prepared in accordance with U.S. Generally Accepted Accounting Principles (US GAAP), but taxable income is computed based on the applicable tax legislation, interpretations and Canadian Revenue Agency (CRA) assessment practices. As such, adjustments are typically made to EBT to arrive at taxable income. Generally, to arrive at taxable income EBT is increased by amounts that are temporarily or permanently not deductible for tax purposes and reduced by amounts that are deductible for tax purposes, but which have not been deducted in computing EBT.

6.0 TIMING/TEMPORARY DIFFERENCES

There are a number of adjustments made to EBT to arrive at taxable income and most of these adjustments are made to account for timing differences. Adjustments for timing differences are temporary in nature and are necessary in circumstances where the treatment for financial accounting purposes differs from the treatment for tax purposes, but ultimately both treatments lead to the same result over time. The need for adjustments to EBT due to timing differences can arise when:

1. Expenditures are both capitalized and depreciated over time under both financial accounting and tax requirements, but the depreciation rates and depreciation methodology differ;
2. accrued costs are expensed for financial accounting purposes, but tax deductions are allowed only when cash payments are made (i.e., Other Post-Employment Benefits (OPEB) and contingent liabilities); or
3. Costs are expensed for financial accounting purposes but are capitalized for tax purposes, or vice versa (i.e., capitalized overheads).

Common items that increase EBT (i.e., are added back to EBT for tax purposes) include accounting depreciation, contingent liabilities, accounting losses, accrued expenditures related to OPEB and revenue that has been received but not recognized for accounting purposes.[2]

Common items that reduce EBT (i.e., they are deducted from EBT for tax purposes) include capital cost allowance, the deductible portion of capitalized overhead costs, accounting gains, OPEB payments, and expenses incurred for which a deferral and variance account has been set up on the balance sheet, rather than shown as deductions through the income statement.

Sections 6.1 to 6.3 below provide more detailed descriptions of the key timing differences and how they have historically impacted and will continue to impact Hydro One's Regulatory Tax for the test years.

6.1 ACCOUNTING DEPRECIATION VS. TAX CAPIAL COST ALLOWANCE (CCA)

Accounting depreciation is based upon US GAAP while tax depreciation is based upon tax legislation. This leads to differences in the calculation methods, asset classifications and the applicable depreciation rates. Accounting depreciation is generally computed on a straight-line basis while tax depreciation, also known as capital cost allowance (CCA),

[2] For example, income received with respect to a deferral account that has been set-up on the balance sheet rather than shown as additional income on the income statement.

is generally determined on a declining balance basis. Over the life of a particular asset, the tax CCA deductions will be higher in the earlier years and decline over time while the accounting depreciation will remain constant. This difference gives rise to one of the most significant timing differences, which must be reflected through adjustments to EBT. Regulatory Taxes will generally be lower in years where CCA tax deductions are greater than accounting depreciation but higher in years where CCA tax deductions are lower than accounting depreciation.

The government introduced the Reaccelerated Investment Incentive (RII) for accelerated capital cost allowance in March 2026. RII increases the first-year tax deductions but reduces the UCC pool, resulting in smaller deductions later. The new legislation allows 3 times normal CCA for assets in-serviced between 2025 to 2029, 2 times normal CCA for assets in-serviced 2030 to 2033 and expires in 2034. The tax impacts from the re-introduction of accelerated CCA rules are reflected in the tax calculation for test years.[3]

6.2 ACCRUAL VS CASH DISBURSEMENT

Net income determined under US GAAP generally allows a deduction for expenditures that have been incurred but not necessarily paid (i.e. on an accrual basis). For tax purposes, certain expenditures can be similarly deducted on an accrual basis, but some expenditures are explicitly limited to situations where there is an associated cash payment. Two examples that highlight this different treatment are OPEB costs and contingent liability accruals, which are discussed in Sections 6.2.1 and 6.2.2 below.

6.2.1 OTHER POST EMPLOYMENT BENEFITS

Annual OPEB costs accrued for financial accounting purposes are comprised of amounts that are capitalized into fixed assets as well as amounts that are expensed as operations, maintenance and administration (OM&A) costs. However, for tax purposes, only the

[3] This is in accordance with Ontario Energy Board guidance “Accounting and Rates Direction Regarding Bill C-15 for the Reaccelerated Investment Incentive for Capital Cost Allowance “issued May 06, 2026, the impact of reaccelerated investment incentive (RII) is reflected in the tax calculations for the test years. Tax benefits from RII for 2025 to 2027 are included in the 1592 variance account.

portion of annual OPEB costs that is actually paid for in the year can be deducted. OPEB payments are generally paid many years after they are accrued and, as a result, can give rise to significant timing differences between when the OPEB costs are accrued for financial accounting purposes and when the OPEB costs may be deducted for tax purposes.

Regulatory Taxes will generally be higher in years where OPEB expenditures are accrued without offsetting cash disbursements. Conversely, Regulatory Taxes will generally be lower in years where OPEB related cash disbursements are in excess of those accrued. The total available OPEB tax deduction over time does not change based on whether OPEB charges are recognized as OM&A costs or capitalized into fixed assets. However, revenue requirement is directly impacted by the method through which OPEB costs are recognized and recovered.

If OPEB amounts are capitalized into fixed assets, their recovery occurs over the life of the capital assets, as part of annual accounting depreciation. If OPEB amounts are expensed as OM&A costs, their recovery is immediate. Regulatory Taxes will be higher when OPEB amounts are expensed (as the immediate recovery of OMA is higher) as compared to when capitalized. Even though the total tax deductions from annual OPEB costs remains unchanged, irrespective of the capital or expense treatment, Regulatory Taxes would be lower in years where more OPEB costs are capitalized and higher in years where more OPEB costs are expensed, all other things being equal.

6.2.2 CONTINGENT LIABILITIES

Contingent liabilities (costs), which are recognized on Hydro One's financial statements, represent liabilities that may be incurred depending on the outcome of uncertain events, and are also known as accounting reserves. Where an accounting provision is recognized for certain contingent costs that the utility may have to incur in the future, the accrued expenditure will reduce the EBT of the utility. In each subsequent year, the balance for the contingent liability/accounting reserve is reviewed and may be adjusted by the utility to

reflect new information available at that time. The balance may be adjusted upward or downward, with EBT either decreasing or increasing, respectively, as a result.

For tax purposes, the costs and deductions associated with a contingent liability or accounting reserve are not reflected until the obligation is settled. Therefore, to the extent that NIBT has been increased (or decreased) by the contingent liability or accounting reserve accrual, the NIBT impact must be reversed in computing taxable income.

6.3 CAPITALIZED OVERHEAD COSTS FOR ACCOUNTING VS. FOR TAX

Annually, for financial accounting purposes and in accordance with US GAAP, Hydro One capitalizes a certain portion of overhead costs to fixed assets. That ability to capitalize overhead costs for financial accounting purposes is distinct from the ability to capitalize overhead costs for tax purposes. For the purpose of determining taxable income, capitalized overhead costs can be deducted immediately on the basis that they are not directly related to the acquisition or construction of capital assets and are considered to be recurring costs incurred as part of the day-to-day expenses of operating the business (Tax Deductible Capitalized Overheads). Tax Deductible Capitalized Overheads are based on tax legislation, jurisprudence, interpretation and principles accepted by the CRA and are not dependent on accounting treatments established under applicable accounting standards (US GAAP or IFRS). In light of this contrasting treatment, overhead costs being capitalized under US GAAP, but expensed for tax purposes, are another significant source of deductible timing differences, which have the effect of reducing Hydro One's taxable income, the related Regulatory Taxes, and ultimately its revenue requirement.

6.4 CAPITALIZED OVERHEAD UPDATED APPROACH

In its 2023–2027 rebasing application, Hydro One adopted a revised tax approach that included additional deductions for capitalized overheads when forecasting for regulatory taxes. Concurrently, tax returns for the 2016–2022 period were updated to reflect this new approach for capitalized overheads.

To address uncertainty around CRA acceptance of this revised approach, a regulatory variance account was established in EB-2021-0110 to: (i) capture incremental tax savings arising from the amended 2016–2022 tax returns once those years are finalized (i.e., audited or statute-barred, whichever occurs later) and (ii) capture any additional tax costs for the 2023–2027 period if the CRA ultimately rejects the updated approach.

As of December 31, 2025, the CRA has not challenged Hydro One's current approach to deduct capital overheads. As such, the balance recorded in the regulatory account reflects that tax savings from 2016 to 2020 to be returned to rate payers. Tax Savings from 2021 and 2022 have not been statute barred or audited, and therefore not reflected in the regulatory account. The Capitalized Overheads Tax Variance Account, as further described in Exhibit G-01-03, section 4.5, is proposed for discontinuance. While the required journal entries are currently expected to be substantially recorded by the end of 2027, additional entries may be required beyond 2027 as a result of CRA audits, reassessments, or other determinations relating to the 2023-2027 taxation years.

7.0 TAX TREATMENT OF REGULATORY ASSETS AND LIABILITIES

Regulatory Assets and Regulatory Liabilities are typically recognized on utilities' balance sheets for foregone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of Regulatory Account balances is determined by the OEB.

Regulatory Assets and Regulatory Liabilities have not been included in computing Regulatory Taxes for purposes of calculating revenue requirement in accordance with Section 2.8.10 of the Transmission Filing Requirements issued October 30, 2025 and Section 2.6.2.1 the Distribution Filing Requirements issued December 16, 2025.

8.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between Hydro One's regulatory NIBT and taxable income for the test years 2028 to 2032 is provided in Exhibit E-09-02, Attachment 1. This Schedule contains the

income tax computation. It also shows how taxable income is computed by making adjustments to the regulatory EBT for items such as depreciation and CCA. The calculation of CCA is provided in Exhibit E-09-02, Attachment 2. Reconciliation between accounting fixed asset additions and net tax additions is provided in Exhibit E-09-02, Attachments 7 and 8. Reconciliation between Hydro One's accounting NIBT and taxable income for the historical years 2022, 2023 and 2024 is provided in Exhibit E-09-02, Attachment 3. The calculation of CCA for the historical years is provided in Exhibit E-09-02, Attachment 4.

In order to make it easier to follow these reconciliations, Hydro One has placed these adjustments into the following five categories:

1. Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, accounting depreciation versus CCA);
2. Deferral accounts not included in the revenue requirement;
3. Reversal of accounting adjustments not included in the revenue requirement;
4. Recurring items not in the revenue requirement; and
5. Items whose impact is immaterial in total, and as such, have not been included in Hydro One's business plan.

9.0 INTEGRITY CHECKS

Hydro One has performed the integrity checks described in Section 2.6.2.1 of the Distribution Filing Requirements and Section 2.8.10.2 of the Transmission Filing Requirements, with exceptions noted below:

- The capital additions in the undepreciated capital cost (UCC) schedule do not agree with the rate base in the historical, bridge and test years in Exhibit E-09-02, Attachment 2. This is primarily due to capitalized costs that are deductible (and not capitalized) for tax. Please see reconciliation provided in Exhibit E-0902, Attachments 7 and 8.

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CALCULATION OF UTILITY INCOME TAXES

Attachment 1: Calculation of Utility Income Taxes – Bridge and Test Years

Attachment 2: Calculation of Capital Cost Allowance – Bridge and Test Years

Attachment 3: Calculation of Utility Income Taxes – Historical Years

Attachment 4: Calculation of Capital Cost Allowance – Historical Years

Attachment 5: Calculation of Tax Credits – Bridge and Test Years

Attachment 6: Calculation of Tax Credits – Historical Years

Attachment 7: Reconciliation of Accounting to Tax Additions – Historical Years

Attachment 8: Reconciliation of Accounting to Tax Additions – Bridge and Test Years

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CALCULATION OF UTILITY INCOME TAXES – BRIDGE AND TEST YEARS

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CALCULATION OF CAPITAL COST ALLOWANCE – BRIDGE AND TEST YEARS

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CALCULATION OF INCOME TAX - HISTORICAL YEARS

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CALCULATION OF CAPITAL COST ALLOWANCE – HISTORICAL YEARS

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CALCULATION OF TAX CREDITS – BRIDGE AND TEST YEARS

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CALCULATION OF TAX CREDITS – HISTORICAL YEARS

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ACCOUNTING TO TAX ADDITIONS – HISTORICAL YEARS

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ACCOUNTING TO TAX ADDITIONS – TEST YEARS

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CORPORATE INCOME TAXES – HOSSM

1.0 OVERVIEW

This Exhibit explains how HOSSM calculates its income tax expenses for the purposes of rate recovery. Exhibit E-09-04, Attachments 1 to 4 contain detailed calculations of income tax for the historical, bridge and test years, including supporting schedules and reconciliations, as needed. The information provided in this Application is consistent with Section 2.8.10 of the Transmission Filing Requirements.

2.0 OVERVIEW OF INCOME TAXES

2.1 INTRODUCTION

HOSSM is a limited partnership pursuant to the *Limited Partnerships Act* (Ontario). A partnership is generally not taxable under the *Income Tax Act*. A partnership is required to compute its taxable income, which is then allocated to its partners. HOSSM is engaged in the transmission of electricity in the Sault Ste. Marie area.

On October 31, 2016, Hydro One Inc. and 1937672 Ontario Inc. completed the share purchase of the HOSSM entities (formerly Great Lakes Power Transmission LP). As part of the transaction, the partnership changed its name to Hydro One Sault Ste. Marie LP on January 16, 2017.

HOSSM is effectively 99.99% indirectly owned by Hydro One Networks Inc. (HONI) through a series of limited partnerships. The remaining nominal interests are held by Hydro One group entities acting as general partners of the partnerships.

The partners of HOSSM on June 30, 2026, are as follows:

Members	Description
Hydro One Networks Inc. (“HONI”)	Holds effectively 99.99% of HOSSM LP though a tired partnership structure.
Hydro One Sault Ste. Marie Holdings Inc.	A corporation owned directly by Hydro One Inc., and the .01% Hydro One Sault Ste. Marie Holdings LP

2.2 REGULATORY INCOME TAX EXPENSE

Regulatory Income Taxes for HOSSM are determined by applying the statutory tax rate to the regulatory taxable income allocated to HONI and HOSSM Inc., the taxable corporate partners of HOSSM.

2.3 INCOME TAX RATE (FEDERAL AND ONTARIO)

A combined income tax rate of 26.5% has been used for the 2027 and 2028 Test Years, as set out in Table 1 below, comprising a federal rate of 15% and a provincial rate of 11.5%. Any variance between actual taxes payable and forecast taxes, because of tax policy and legislation changes, will be captured in a variance account for tax rate changes as per Section 7.1 of the Electricity Distribution Rate Handbook.

Table 1 - Combined Income Tax Rates

	Historical	**Test**	**Test**
	2016-2026	**2027**	**2028**
Federal Tax Rate (%)	15.00	15.00	15.00
Provincial Rate (%)	11.50	11.50	11.50
Total Statutory Tax Rate (%)	**26.50**	**26.50**	**26.50**

3.0 RECONCILIATION BETWEEN REGULATORY NET INCOME BEFORE TAX AND TAXABLE INCOME

Reconciliation between the regulatory net income before tax (NIBT) and taxable income for the 2027 and 2028 Test year is provided in Exhibit E-09-04, Attachment 1. This schedule contains the income tax computation and shows how the taxable income is computed by making adjustments to the regulatory NIBT for items such as depreciation and CCA. The calculation of CCA is provided in Exhibit E-09-04, Attachment 2.

Reconciliation between the accounting NIBT and taxable income for the historical years 2016-2025 is provided in Exhibit E-09-04, Attachment 3. The calculation of CCA for the historical years is provided in in Exhibit E-09-04, Attachment 4.

To make it easier to follow these reconciliations, HOSSM has separated the tax adjustments into the following categories:

1. Recurring items that must be added (deducted) because they have been included in the OM&A expenses in arriving at the revenue requirement, or for which appropriate tax adjustments are made (for example, depreciation versus CCA); and
2. Recurring items not in the revenue requirement.

4.0 OVERVIEW OF PROCESS TO ARRIVE AT TAXABLE INCOME

The starting point for the computation of HOSSM taxable income is the NIBT as shown on the utility's income statement for the year. The NIBT is prepared by using U.S. Generally Accepted Accounting Principles, but taxable income is computed using the relevant tax legislation, interpretations and assessing practices. Therefore, there are a number of adjustments that are typically made to the NIBT to arrive at taxable income and most of these adjustments are made to account for timing differences. Adjustment for timing differences can arise when: (1) expenditures are both capitalized and depreciated over time for both financial accounting and tax requirements, but the depreciation rates and depreciation methodology are different; or (2) costs that are expensed for financial accounting purposes but not for tax purposes or vice versa. Common item that increases NIBT (i.e., it is added back to NIBT for tax purposes) is financial accounting depreciation and amortization with CCA being the common item that reduces NIBT (i.e., it is deducted from NIBT for tax purposes). Consequently, it is imperative that the NIBT be adjusted for amounts that have been included (or deducted) for accounting purposes that are not income (or deductible) for tax return purposes.

5.0 TAXABLE TREATMENT OF REGULATORY ASSETS AND REGULATORY LIABILITIES

Regulatory assets and regulatory liabilities are typically recognized by the utilities' balance sheets for forgone revenue or for expenses that have been incurred, for which recovery will be sought from ratepayers through future rates. Disposition of the deferral accounts is determined by the OEB.

For example, in the illustrative example shown in Table 2, assuming that a 26.5% tax rate and a $100 expense is incurred, the utility will record a regulatory asset for the expense to be recovered in the future while tax will be allowed a deduction of the $100 the year in which the expense is incurred in computing taxable income. If the OEB subsequently approves recovery of this expense over a two-year period, the utility will include the approved recovery amounts in computing taxable income for the year in which it is billed to ratepayers. The net result is that the utility has recovered the $100 cost although the income or expense has been taxed or deducted in different years.

Table 2 - Example of the Income Tax Treatment of Regulatory Assets and Regulatory Liabilities Disposition

	Year 1	Year 2	Year 3	Total
Income (deduction)	(100)	50	50	Nil
Tax Refund (payable)	26.5	(13.25)	(13.25)	Nil
Cash Inflow (outflow)	(73.5)	36.75	36.75	Nil

Therefore, regulatory assets and regulatory liabilities have not been included in computing tax payable for purposes of the revenue requirement since the associated tax benefit has or will be obtained through the tax system, generally within a reasonable time horizon (i.e., the application period).

6.0 INTEGRITY CHECKS

HOSSM has performed the integrity checks set described in Section 2.8.10.2 of the Transmission Filing Requirements.

CALCULATION OF UTILITY INCOME TAXES – HOSSM

Attachment 1: Calculation of Utility Income Taxes – Bridge and Test Years

Attachment 2: Calculation of Capital Cost Allowance – Bridge and Test Years

Attachment 3: Calculation of Utility Income Taxes – Historical Years

Attachment 4: Calculation of Capital Cost Allowance – Historical Years

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CALCULATION OF HOSSM UTILITY INCOME TAXES – BRIDGE AND TEST YEARS

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CALCULATION OF HOSSM CAPITAL COST ALLOWANCE – BRIDGE AND TEST YEARS

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HOSSM HISTORICAL TAXABLE INCOME CALCULATION

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HOSSM CALCULATION OF CAPITAL COST ALLOWANCE – HISTORICAL YEARS

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HYDRO ONE NETWORKS INC. INCOME TAX RETURN

Attachment 1: Hydro One Networks Inc. 2025 Income Tax Return

Attachment 2: Hydro One Networks Inc. 2025 Taxable Income – Allocation by Segment

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Federal Tax Instalments

Federal tax instalments

For the taxation year ended 2026-12-31

Business number

The following is a list of instalments payable for the current taxation year, and the last column indicates the instalments payable to the Canada Revenue Agency (CRA). The instalments must be paid on each of the dates indicated below, otherwise non-deductible interest might be charged.

You can pay using one of the methods listed at **canada.ca/payments**. However, when a remittance must mandatorily be made using electronic means, use one of the following electronic payment methods:

- a Canadian financial institution's services;
- the CRA's *My Payment* service, at **canada.ca/cra-my-payment**;
- a pre-authorized debit agreement set up in the CRA's *My Business Account* service, at **canada.ca/my-cra-business-account**;
- a wire transfer.

Monthly instalment workchart

Date	Monthly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2026-01-31	9,710,243	9,710,243			
2026-02-28	9,710,243	9,710,243			
2026-03-31	9,710,243	8,233,748			1,476,495
2026-04-30	9,710,243				9,710,243
2026-05-31	9,710,243				9,710,243
2026-06-30	9,710,243				9,710,243
2026-07-31	9,710,243				9,710,243
2026-08-31	9,710,243				9,710,243
2026-09-30	9,710,243				9,710,243
2026-10-31	9,710,243				9,710,243
2026-11-30	9,710,243				9,710,243
2026-12-31	9,710,232				9,710,232
Totals	116,522,905	27,654,234			88,868,671

Quarterly instalment workchart

Date	Quarterly tax instalments	Refund transferred to instalments	Instalments paid	Cumulative difference	Instalments payable
2026-03-31					
2026-06-30					
2026-09-30					
2026-12-31					
Totals					

Instalment method

Indicate instalment method chosen [1-3] 1

1st Instalment base method

If payment of instalments other than quarterly instalments is delayed, indicate the MONTH in which you want them to begin (1=January, 2=February, etc.). 1

Select this box if you want the instalments to be calculated without taking the applicable threshold into account ☐

Quarterly instalments calculation

The corporation must meet requirements 1 to 5 to be eligible for quarterly instalments for a tax year.

1 –	Is the corporation a Canadian-controlled private corporation (CCPC)?	☐ Yes	☒ No
2 –	Did the corporation claim any deduction under the section 125, during either the current or previous year?	☐ Yes	☒ No
3 –	Is the corporation's, or any of its associated corporations', taxable income for the current or previous year less than or equal to $500,000?	☐ Yes	☒ No
4 –	Is the corporation and any associated corporations' taxable capital employed in Canada for the current or previous year less than or equal to $10,000,000?	☐ Yes	☒ No
5 –	Does the corporation have a perfect compliance history in the last 12 months?	☒ Yes	☐ No

If you do not want to use the quarterly instalments option, select this box to go back to monthly instalments. ☐

1 – 1st Instalment base method

1st Instalment base amount (amount N below)	116,522,905	÷ 12	=	9,710,243
	Monthly instalments required			9,710,243
Quarterly tax instalments required	116,522,905	÷ 4	=	

2 – Combined 1st and 2nd instalment base method

Select this box if you want the first 2 payments* to be calculated without taking the applicable threshold into account? ☐

2nd Monthly instalment base amount

Indicate:	Part I tax		200			
	Parts VI, VI.1 and XIII.1 tax	+				
	Federal adjustment for amalgamation, winding up or transfer	+				
	Provincial tax, other than Alberta, Québec and Ontario	+				
	Ontario tax	+	34,214,186			
	Provincial adjustment for amalgamation, winding up or transfer	+				
	Total	=	34,214,386	÷ 12	= 2,851,199	A
1/12 of estimated current year credits (M below /12)					– 77,750	
	Each of the first two instalment payments				= 2,773,449	B
Total tax from N below			116,522,905			
Amount B above x 2		–	5,546,898			
		=	110,976,007	÷ 10	= 11,097,601	
	Each of the remaining ten instalment payments				= 11,097,601	

2nd Quarterly instalment base amount

Indicate:	Part I tax		200			
	Parts VI, VI.1 and XIII.1 tax	+				
	Federal adjustment for amalgamation, winding up or transfer	+				
	Provincial tax, other than Alberta, Québec and Ontario	+				
	Ontario tax	+	34,214,186			
	Provincial adjustment for amalgamation, winding up or transfer	+				
	Total	=	34,214,386	÷ 4	= 8,553,597	A
1/4 of estimated current year credits (M below /4)					– 233,250	
	The first instalment payment				=	B
Total tax from N below			116,522,905			
Amount B above		–				
		=	116,522,905	÷ 3	= 38,840,969	
	Each of the remaining three instalment payments				=	

* It is the first payment if the quarterly instalments are applicable.

3 – Estimated tax method

Instalment base amount (amount N below)		÷ 12	=	
		Monthly instalments required		
Quarterly tax instalments required		÷ 4	=	

Instalment base calculation

Federal tax		1st instalment base method		Estimated tax method	
Taxable income		525,677,432			
Calculation of tax payable					
Federal part I tax		199,757,424			
Additional tax on personal services business income	+		+		
Additional tax on banks and life insurers	+		+		
Total labour requirements addition to tax	+		+		
Recapture of investment tax credit	+		+		
Refundable tax on a CCPC's investment income	+		+		
Subtotal	=	199,757,424	=		A
Deduction					
Small business deduction					
Investment corporation deduction	+		+		
Federal tax abatement	+	52,567,743	+		
Manufacturing and processing profits deductions	+		+		
Non-business foreign tax credit	+		+		
Business foreign tax credit	+		+		
General tax reduction	+	68,338,066	+		
Logging tax credit	+		+		
Investment tax credit per Schedule 31	+	580,560	+		
Eligible Canadian bank deduction	+		+		
Qualifying environmental trust tax credit	+		+		
Subtotal	=	121,486,369	=		B
Federal tax summary					
Total part I tax payable (A minus B)		78,271,055			C
Part VI tax	+		+		D
Part VI.1 tax	+		+		E1
Part XIII.1 tax	+		+		E2
Parts I, VI, VI.1 and XIII.1 **Total**	=	78,271,055	=		F
Federal adjustments					
Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	78,271,055	=		
Federal adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total federal tax after adjustments	=	78,271,055	=		G
Provincial tax					
Provincial/territorial tax other than Alberta, Québec and Ontario before provincial refundable tax credits	+		+		H
Ontario tax					
Income tax		60,452,905			
Corporate minimum tax paid (credited)	+	-21,268,055			
Special additional tax on life insurance corporations	+				
Total Ontario tax	=	39,184,850 ▶	+ 39,184,850	+	I
Harmonized provincial tax (H + I)					
Provincial/territorial tax other than Alberta and Québec before provincial refundable tax credits	=		39,184,850	=	J

Instalment base calculation (continued)

Provincial adjustments

Adjustment for short taxation years multiplied by 365 and divided by the number of days in the year if less than 365	x	365 / 365	x	365 / 365	
Subtotal	=	39,184,850	=		
Provincial adjustment for amalgamation, winding up or transfer	+		+	N/A	
Total provincial tax after adjustments	=	39,184,850	=		**K**
Total of tax before refundable credits**	=	117,455,905	=		**L**

Estimated current year credits

Investment tax credit refund					
Dividend refund	+		+		
Federal capital gains refund	+		+		
Provincial and territorial capital gains refund	+		+		
Tax withheld at source	+		+		
Canadian journalism labour tax credit	+		+		
Other estimated credits	+		+		
Provincial/territorial refundable tax credits other than Alberta, Québec and Ontario*	+		+		
Ontario refundable tax credits*	+	933,000	+		
Total estimated current year credits	=	933,000	=		**M**
Instalment base amount (L – M)		116,522,905			**N**

* For more details with regards to the impact of the refundable tax credits in the instalment base calculation, consult the Help.

** For instalments payable, the amount on line G will only be included in the amount of line L when it exceeds $3,000. The same rule applies to line K.

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

200

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) 001

Corporation's name
002 HYDRO ONE NETWORKS INC.

Address of head office
Has this address changed since the last time the CRA was notified? . . . . . 010 Yes ☐ No ☒
If **yes**, complete lines 011 to 018.
011 483 BAY STREET, 8TH FLOOR
012 SOUTH TOWER
City: 015 TORONTO
Province, territory, or state: 016 ON
Country (other than Canada): 017 CA
Postal or ZIP code: 018 M5G 2P5

Mailing address (if different from head office address)
Has this address changed since the last time the CRA was notified? . . . . . 020 Yes ☐ No ☒
If **yes**, complete lines 021 to 028.
021 c/o TAX DEPARTMENT
022 483 BAY STREET 8TH FLOOR
023 SOUTH TOWER
City: 025 TORONTO
Province, territory, or state: 026 ON
Country (other than Canada): 027
Postal or ZIP code: 028 M5G 2P5

Location of books and records (if different from head office address)
Has this address changed since the last time the CRA was notified? . . . . . 030 Yes ☐ No ☒
If **yes**, complete lines 031 to 038.
031 483 BAY STREET 8TH FLOOR
032 SOUTH TOWER
City: 035 TORONTO
Province, territory, or state: 036 ON
Country (other than Canada): 037
Postal or ZIP code: 038 M5G 2P5

040 **Type of corporation at the end of the tax year** (tick one)
- ☐ 1 Canadian-controlled private corporation (CCPC)
- ☐ 2 Other private corporation
- ☐ 3 Public corporation
- ☒ 4 Corporation controlled by a public corporation
- ☐ 5 Other corporation (specify)

If the type of corporation changed during the tax year, provide the effective date of the change . . . . . 043 Year Month Day

To which tax year does this return apply?
Tax year start: 060 Year Month Day 2025-01-01
Tax year-end: 061 Year Month Day 2025-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . . 063 Yes ☐ No ☒
If **yes**, provide the date control was acquired . . . . . 065 Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . . 066 Yes ☐ No ☒

Is the corporation a professional corporation that is a member of a partnership? . . . . . 067 Yes ☐ No ☒

Is this the first year of filing after:
Incorporation? . . . . . 070 Yes ☐ No ☒
Amalgamation? . . . . . 071 Yes ☐ No ☒
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . . 072 Yes ☐ No ☒
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . . 076 Yes ☐ No ☒

Is this the final return up to dissolution? . . . . . 078 Yes ☐ No ☒

If an election was made under section 261, state the functional currency used 079

Is the corporation a resident of Canada? 080 Yes ☒ No ☐
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . . 082 Yes ☐ No ☒
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- ☐ 1 Exempt under paragraph 149(1)(e) or (l)
- ☐ 2 Exempt under paragraph 149(1)(j)
- ☐ 4 Exempt under other paragraphs of section 149

Do not use this area
095 096 898

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.
Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160		23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164	X	14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165	X	15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167	X	T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170	X	29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173		50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		———
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202	X	2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206	X	6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213	X	13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits or zero-emission technology manufacturing profits?	227		27
Is the corporation claiming an investment tax credit?	231	X	31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232	X	T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	———
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
If the corporation is a resident of Canada, did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269	X	54
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273		63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274		59
Is the corporation subject to the additional 1.5% tax on banks and life insurers?	276		68
Is the corporation a covered entity that redeemed, acquired or cancelled equity of the corporation in the tax year?	277		56
Is the corporation subject to the excessive interest and financing expenses limitation (EIFEL) rules contained primarily in sections 18.2 and 18.21, or is it a party to any election under the EIFEL rules?	278		130

Additional information

Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	Yes	No X
Is the corporation inactive?	280	Yes	No X
Did the corporation meet the definition of substantive CCPC under subsection 248(1) at any time during the tax year?	290	Yes	No X

What is the corporation's main revenue-generating business activity? 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electricity	285	100.000 %
286		287	%
288		289	%

Did the corporation immigrate to Canada during the tax year?	291	Yes	No X
Did the corporation emigrate from Canada during the tax year?	292	Yes	No X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293	Yes	No
If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible	294	Year Month Day	
If the corporation's major business activity is construction, did you have any subcontractors during the tax year?	295	Yes	No

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300 613,168,945	A
Deduct:				
Charitable donations from Schedule 2	311	1,679,294		
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331	85,812,219		
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Restricted interest and financing expenses from Schedule 4	336			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities	352			
Subtotal		87,491,513 ▶	87,491,513	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")			525,677,432	C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360 525,677,432	

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . . . **400** _____ A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** _____ B

Business limit (see notes 1 and 2 below) . . . . . **410** _____ C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C _____ x **415** *** _____ D = ... _____ E
90,000

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** _____ – 50,000 = . . _____ F

Amount C _____ x Amount F _____ = ... _____ G
100,000

The greater of amount E and amount G **422** _____ H

Reduced business limit (amount C **minus** amount H) (if negative, enter "0") . . . . . **426** _____ I

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . _____ J

Reduced business limit after assignment (amount I **minus** amount J) . . . . . **428** _____ K

Small business deduction – Amount A, B, C, or K, whichever is the least . . . . _____ x 19 % = **430** _____

Enter amount from line 430 at amount L on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. This amount is reported at line 745 of the corresponding Schedule 7. Each corporation with such income has to file a Schedule 7.

Small business deduction (continued)

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount 490	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] 500	N Business limit assigned to corporation identified in column L [4] 505
1.				

Total 510 _____ Total 515 _____

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Taxable income from line 360 on page 3			A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B	
Amount 13K from Part 13 of Schedule 27		C	
Personal services business income	432	D	
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*		E	
Aggregate investment income from line 440 on page 6**		F	
Subtotal (**add** amounts B to F)		▶	G
Amount A **minus** amount G (if negative, enter "0")			H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %			I

Enter amount I on line 638 on page 8.

* This is not applicable to substantive CCPCs.

** Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, a substantive CCPC, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3			525,677,432 J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		K	
Amount 13K from Part 13 of Schedule 27		L	
Personal services business income	434	M	
Subtotal (**add** amounts K to M)		▶	N
Amount J **minus** amount N (if negative, enter "0")			525,677,432 O
General tax reduction – Amount O **multiplied** by 13 %			68,338,066 P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year or substantive CCPCs at any time in the tax year

Aggregate investment income from Schedule 7 . . . . . **440** _____ x 30 2 / 3 % = ... _____ A

Foreign non-business income tax credit from line 632 on page 8 . . . . . _____ B

Foreign investment income from Schedule 7 . . . . . **445** _____ x 8 % = _____ C

Subtotal (amount B **minus** amount C) (if negative, enter "0") _____ ▶ _____ D

Amount A **minus** amount D (if negative, enter "0") . . . . . _____ E

Taxable income from line 360 on page 3 . . . . . _____ F

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least* . . . . . _____ G

Foreign non-business income tax credit from line 632 on page 8 . . . . _____ x 75 / 29 = _____ H

Foreign business income tax credit from line 636 on page 8 . . _____ x 4 = _____ I

Subtotal (**add** amounts G to I) _____ ▶ _____ J

Subtotal (amount F **minus** amount J) _____ K x 30 2 / 3 % = _____ L

Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9) . . . . . _____ M

Refundable portion of Part I tax – Amount E, L, or M, whichever is the least . . . . . **450** _____ N

* This is not applicable to substantive CCPCs. . . . . .

Refundable dividend tax on hand

Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (line 530 of the preceding tax year)		520	A
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (line 545 of the preceding tax year) (if negative, enter "0")		535	B
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)	C		
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)	D		
Subtotal (amount C **plus** amount D)	▶		E
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary		525	F
ERDTOH dividend refund for the previous tax year		570	G
Refundable portion of Part I tax (from line 450 on page 6)			H
Part IV tax before deductions (amount 2A from Schedule 3)	I		
Part IV tax allocated to ERDTOH (amount E)	J		
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)	K		
Subtotal (amount I **minus** total of amounts J and K)	▶		L
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary		540	M
NERDTOH dividend refund for the previous tax year		575	N
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)			O
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount L **minus** amount O) (if negative enter "0")			P
NERDTOH at the end of the tax year (total of amounts B, H, M, and P **minus** amount N) (if negative, enter "0")		545	
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount E **minus** the amount, if any, by which amount O exceeds amount L) (if negative, enter "0")			Q
ERDTOH at the end of the tax year (total of amounts A, F, and Q **minus** amount G) (if negative, enter "0")		530	

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)	303,485,186	AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)		DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")		GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 %	550	199,757,424	A
Additional tax on personal services business income (section 123.5)			
Taxable income from a personal services business 555 _____ x 5 % =	560		B
Additional tax on banks and life insurers from Schedule 68	565		C
Total labour requirements addition to tax	580		D
Recapture of investment tax credit from Schedule 31	602		E

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) or substantive CCPC's investment income (if it was a CCPC throughout the tax year or a substantive CCPC at any time in the tax year)

Aggregate investment income from line 440 on page 6		F
Taxable income from line 360 on page 3		G
Deduct:		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least*		H
Net amount (amount G **minus** amount H)		I
Refundable tax on CCPC's or substantive CCPC's investment income – 10 2 / 3 % of whichever is less: amount F or amount I	604	J
Subtotal (**add** amounts A to E and J)	199,757,424	K

Deduct:			
Small business deduction from line 430 on page 4			L
Federal tax abatement	608	52,567,743	
Manufacturing and processing profits deduction and zero-emission technology manufacturing deduction from Schedule 27	616		
Investment corporation deduction	620		
Taxed capital gains 624			
Federal foreign non-business income tax credit from Schedule 21	632		
Federal foreign business income tax credit from Schedule 21	636		
General tax reduction for CCPCs from amount I on page 5	638		
General tax reduction from amount P on page 5	639	68,338,066	
Federal logging tax credit from Schedule 21	640		
Eligible Canadian bank deduction under section 125.21	641		
Federal qualifying environmental trust tax credit	648		
Investment tax credit from Schedule 31	652	580,560	
Subtotal		121,486,369	M
Part I tax payable – Amount K **minus** amount M		78,271,055	N

Enter amount N on line 700 on page 9.

* This is not applicable to substantive CCPCs.

Privacy notice

Personal information (including the SIN) is collected and used to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be disclosed to other federal, provincial, territorial, aboriginal or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, and to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount N on page 8	700	78,271,055
Part II.2 tax payable from Schedule 56	705	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part VI.2 tax payable from Schedule 67	725	
Part XII.7 tax payable from Schedule 78	726	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		78,271,055

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	38,251,850
Total tax payable	770	116,522,905 A

Deduct other credits:

Investment tax credit refund from Schedule 31	780		
Dividend refund from amount JJ on page 7	784		
Federal capital gains refund from Schedule 18	788		
Federal qualifying environmental trust tax credit refund	792		
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795		
Canadian film or video production tax credit (Form T1131)	796		
Film or video production services tax credit (Form T1177)	797		
Canadian journalism labour tax credit from Schedule 58	798		
Tax withheld at source	800		
Total payments on which tax has been withheld 801			
Provincial and territorial capital gains refund from Schedule 18	808		
Provincial and territorial refundable tax credits from Schedule 5	812		
Tax instalments paid	840	144,177,139	
Total credits	890	144,177,139 ▶	144,177,139 B

Balance (amount A **minus** amount B) -27,654,234

If the result is negative, you have **a refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, the CRA does not charge or refund a difference of $2 or less.

Refund code 894 2 Refund 27,654,234 Balance owing

For information on how to enrol for direct deposit, go to **canada.ca/cra-direct-deposit**.

For information on how to make your payment, go to **canada.ca/payments**.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☐

If this return was prepared by a tax preparer for a fee, provide their:
EFILE number 920
RepID 925

Certification

I, 950 Yam (Last name) 951 Selma (First name) 954 Director of Tax (Position, office, or rank),
am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2026-06-22 (Date (yyyy/mm/dd)) Signature of the authorized signing officer of the corporation 956 mber

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☒ No ☐

958 Name of other authorized person 959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

T2 E (26)

Schedule of Instalment Remittances

Name of corporation contact Selma Yam

Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Total 2025 instalments	144,177,139

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 144,177,139 **A**

Total instalments credited to the taxation year per T9 144,177,139 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 100

Form identifier 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Balance sheet information

Account	Description	GIFI		Current year	Prior year
	Assets				
	Total current assets	1599	+	2,349,000,000	2,028,000,000
	Total tangible capital assets	2008	+	44,859,000,000	41,912,000,000
	Total accumulated amortization of tangible capital assets	2009	–	14,770,000,000	14,100,000,000
	Total intangible capital assets	2178	+	1,829,000,000	1,748,000,000
	Total accumulated amortization of intangible capital assets	2179	–	963,000,000	875,000,000
	Total long-term assets	2589	+	4,618,000,000	4,011,000,000
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	37,922,000,000	34,724,000,000
	Liabilities				
	Total current liabilities	3139	+	3,662,772,926	3,341,109,622
	Total long-term liabilities	3450	+	21,524,000,000	19,178,000,000
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	25,186,772,926	22,519,109,622
	Shareholder equity				
	Total shareholder equity (mandatory field)	3620	+	12,735,227,074	12,204,890,378
	Total liabilities and shareholder equity	3640	=	37,922,000,000	34,724,000,000
	Retained earnings				
	Retained earnings/deficit – end (mandatory field)	3849	=	9,815,227,074	9,288,890,378

* Generic item

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Income statement information

Description	GIFI

Operating name	0001	
Description of the operation	0002	
Sequence number	0003	01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	8,762,128,544	8,249,233,295
	Cost of sales	8518	–	4,340,672,336	4,014,988,561
	Gross profit/loss	8519	=	4,421,456,208	4,234,244,734
	Cost of sales	8518	+	4,340,672,336	4,014,988,561
	Total operating expenses	9367	+	2,953,223,181	2,937,695,525
	Total expenses (mandatory field)	9368	=	7,293,895,517	6,952,684,086
	Total revenue (mandatory field)	8299	+	8,823,254,777	8,278,400,709
	Total expenses (mandatory field)	9368	–	7,293,895,517	6,952,684,086
	Net non-farming income	9369	=	1,529,359,260	1,325,716,623
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before taxes and extraordinary items	9970	=	1,529,359,260	1,325,716,623
	Total – other comprehensive income	9998	=	3,709,572	-2,590,557
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–	133,059,361	32,779,668
	Future (deferred) income tax provision	9995	–	77,963,203	149,341,361
	Total – Other comprehensive income	9998	+	3,709,572	-2,590,557
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	1,322,046,268	1,141,005,037

Canada Revenue Agency / Agence du revenu du Canada

Schedule 141

General Index of Financial Information (GIFI) – Additional Information

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Corporations need to complete all parts of this schedule that apply and include it with their T2 return along with their other GIFI schedules.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI), and Guide T4012, T2 Corporation – Income Tax Guide.

Part 1 – Information on the person primarily involved with the financial information

Can you identify the person* specified in the heading of Part 1? . . . . . **111** Yes [X] No [ ]

If you answered **no**, go to Part 2.

Does that person have a professional designation in accounting? . . . . . **095** Yes [X] No [ ]

Is that person connected** with the corporation? . . . . . **097** Yes [X] No [ ]

* A person primarily involved with the financial information is a person who has more than a 50% involvement in preparing the financial information that the T2 return is based on. For example, if three persons prepared the financial information by doing respectively 30%, 30%, and 40% of the work, answer **no** at line 111. If they did respectively 10%, 20%, and 70% of the work, answer **yes** at line 111 and complete Part 1 by referring only to the third person.

** A person connected with a corporation can be: (i) a shareholder of the corporation who owns more than 10% of the common shares; (ii) a director, an officer, or an employee of the corporation; or (iii) a person not dealing at arm's length with the corporation.

Part 2 – Type of involvement

Choose one or more of the following options that represent your involvement and that of the person referred to in Part 1:

Completed an auditor's report . . . . . **300** [ ]

Completed a review engagement report . . . . . **301** [ ]

Conducted a compilation engagement . . . . . **302** [ ]

Provided accounting services . . . . . **303** [X]

Provided bookkeeping services . . . . . **304** [ ]

Other (please specify) **305**

Part 3 – Reservations

If you selected option **1** (300) or **2** (301) in Part 2 above, answer the following question:

Has the person referred to in Part 1 expressed a reservation? . . . . . **099** Yes [ ] No [ ]

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . **101** Yes [X] No [ ]

Did the corporation have any subsequent events? . . . . . **104** Yes [ ] No [X]

Did the corporation re-evaluate its assets during the tax year? . . . . . **105** Yes [X] No [ ]

Did the corporation have any contingent liabilities during the tax year? . . . . . **106** Yes [X] No [ ]

Did the corporation have any commitments during the tax year? . . . . . **107** Yes [X] No [ ]

Does the corporation have investments in joint venture(s) or partnership(s)? . . . . . **108** Yes [X] No [ ]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income (OCI) as a result of an impairment loss in the tax year, a reversal of an impairment loss recognized in a previous tax year, or a change in fair value during the tax year? . . . . . **200** Yes [X] No [ ]

If **yes**, enter the amount recognized:

		In net income Increase (decrease)		**In OCI** Increase (decrease)
Property, plant, and equipment	**210**		**211**	
Intangible assets	**215**		**216**	
Investment property	**220**			
Biological assets	**225**			
Financial instruments	**230**		**231**	3,041,341
Other	**235**		**236**	

Financial instruments

Did the corporation derecognize any financial instrument(s) during the tax year (other than trade receivables)? . . . . . **250** Yes [ ] No [X]

Did the corporation apply hedge accounting during the tax year? . . . . . **255** Yes [X] No [ ]

Did the corporation discontinue hedge accounting during the tax year? . . . . . **260** Yes [ ] No [X]

Adjustments to opening equity

Was an amount included in the opening balance of retained earnings or equity, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current tax year? . . . . . **265** Yes [ ] No [X]

If **yes**, you have to maintain a separate reconciliation.

Part 5 – Information on the person who prepared the T2 return

If the person who prepared the T2 return has a professional designation in accounting but is not the person identified in Part 1, choose all of the following options that apply:

Prepared the T2 return and the financial information contained therein . . . . . **310** [ ]

The client provided the financial statements . . . . . **311** [ ]

The client provided a trial balance . . . . . **312** [ ]

The client provided a general ledger . . . . . **313** [ ]

Other (please specify) **314**

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

13(7.4) ELECTION:
The Taxpayer is electing under subsection 13(7.4) of the Income Tax Act with r
espect to amounts that would normally be included in income under paragraph 12
(1)(x). The amount elected to reduce the cost of depreciable property instead
of being included in income is $535,762,900.

1. DESCRIPTION OF THE BUSINESS

Hydro One Networks Inc. (Hydro One Networks or the Company) was incorporated
on March 4, 1999 under the Business
Corporations Act (Ontario) and is a wholly-owned subsidiary of Hydro One Inc.
(Hydro One). The Company owns and operates
regulated transmission and distribution businesses. The regulated
transmission business (Transmission Business) operates a
high-voltage electrical transmission network that represents substantially
all of the licensed transmission capacity in Ontario. The
regulated distribution business (Distribution Business) operates a
low-voltage electrical distribution network that distributes
electricity from the transmission system, or directly from generators, to
customers within Ontario. These businesses are
regulated by the Ontario Energy Board (OEB).

Rate Setting

Transmission

On August 5, 2021 Hydro One Networks filed a custom Joint Rate Application
(JRAP) for distribution and transmission revenue
requirements for the 2023 to 2027 period. On November 29, 2022, the OEB
issued a Decision and Order (JRAP Decision)
approving Hydro One Networks' transmission revenue requirement of $1,952
million for 2023, $2,073 million for 2024,
$2,168 million for 2025, $2,277 million for 2026 and $2,362 million for 2027.
Revenue requirements presented for 2024 to 2027
do not reflect the actual or expected updates resulting from the annual
application process with the regulator to reflect OEB inflation factors.

Distribution

On November 29, 2022, the OEB issued its JRAP Decision approving Hydro One
Networks' distribution revenue requirement of
$1,727 million for 2023, $1,813 million for 2024, $1,886 million for 2025,
$1,985 million for 2026 and $2,071 million for 2027.
Revenue requirements presented for 2024 to 2027 do not reflect the actual or
expected updates resulting from the annual
application process with the regulator to reflect the latest OEB inflation
factors.

2. SIGNIFICANT ACCOUNTING POLICIES

Basis of Accounting

These unconsolidated financial statements (Financial Statements) are prepared
and presented in accordance with United States
(U.S.) generally accepted accounting principles (GAAP) and in Canadian
dollars.
The Financial Statements have been prepared solely for the purpose of filing
the Company's income tax return. Since these
Financial Statements have not been prepared for general purposes, some users
may require additional information.
Consolidated financial statements of Hydro One for the year ended December
31, 2025 have been prepared and are publicly available.

3. DEPRECIATION, AMORTIZATION AND ASSET REMOVAL COSTS

Year ended December 31 (millions of dollars)	2025	2024
Depreciation of property, plant and equipment	838	794
Amortization of intangible assets	88	81

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

Amortization of regulatory assets 2 10
Depreciation and amortization 928 885
Asset removal costs 142 145
1,070 1,030
4. FINANCING CHARGES
Year ended December 31 (millions of dollars) 2025 2024
Interest on long-term debt (Note 20) 741 682
Interest on regulatory accounts 23 25
Interest (income) on inter-company demand facility (Note 20) 7 (1)
Other 23 19
Less: Interest capitalized on construction and development in progress (104)
(85)690 640
5. ACCOUNTS RECEIVABLE
As at December 31 (millions of dollars) 2025 2024
Accounts receivable - billed 455 428
Accounts receivable - unbilled 664 536
Accounts receivable, gross 1,119 964
Allowance for doubtful accounts (57) (61)
Accounts receivable, net 1,062 903
The following table shows the movements in the allowance for doubtful
accounts for the years ended December 31, 2025 and2024:
Year ended December 31 (millions of dollars) 2025 2024
Allowance for doubtful accounts - beginning (61) (57)
Write-offs 23 18
Additions to allowance for doubtful accounts (19) (22)
Allowance for doubtful accounts - ending (57) (61)
6. OTHER CURRENT ASSETS
As at December 31 (millions of dollars) 2025 2024
Prepaid expenses and other assets 82 84
Regulatory assets (Note 9) 5 50
Materials and supplies 26 26
113 160
7. PROPERTY, PLANT AND EQUIPMENT
As at December 31, 2025 (millions of dollars)
Property, Plant
and Equipment1 Accumulated
Depreciation
Construction
in Progress Total
Transmission 22,595 7,290 2,098 17,403
Distribution 15,237 5,020 289 10,506
Administration and service 2,560 1,095 46 1,511
Other 1,990 1,365 44 669
42,382 14,770 2,477 30,089
1 Includes future use assets totaling $530 million.
As at December 31, 2024 (millions of dollars)
Property, Plant
and Equipment1 Accumulated
Depreciation
Construction
in Progress Total
Transmission 21,235 6,959 1,534 15,810
Distribution 14,239 4,786 308 9,761
Administration and service 2,366 1,051 134 1,449
Other 2,063 1,304 33 792
39,903 14,100 2,009 27,812

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

1 Includes future use assets totaling $542 million.
On December 17, 2024, transmission assets related to Chatham to Lakeshore Transmission Line Project totalling $203 million were transferred from Hydro One Networks to Chatham x Lakeshore Limited Partnership (CLLP), a subsidiary of Hydro One.
See Note 10 - Investment in Subsidiaries.
Financing charges capitalized on property, plant and equipment under construction were $101 million in 2025 (2024 -$81 million).

8. INTANGIBLE ASSETS

As at December 31, 2025 (millions of dollars)

	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	1,578	958	29	649
Other 5	5	-	-	
	1,583	963	29	649

As at December 31, 2024 (millions of dollars)

	Intangible Assets	Accumulated Amortization	Development in Progress	Total
Computer applications software	1,475	870	51	656
Other 5	5	-	-	
	1,480	875	51	656

Financing charges capitalized to intangible assets under development were $3 million in 2025 (2024 - $4 million). The estimated annual amortization expense for intangible assets are as follows: 2026 - $90 million; 2027 - $88 million; 2028 - $83 million; 2029 - $74 million; and 2030 - $65 million.

9. REGULATORY ASSETS AND LIABILITIES

Regulatory assets and liabilities arise as a result of the rate-setting process. Hydro One Networks has recorded the following regulatory assets and liabilities:

As at December 31 (millions of dollars)	2025	2024
Regulatory assets:		
Deferred income tax regulatory asset	3,549	3,263
Broadband deferral	73	48
Post-retirement and post-employment benefits - non-service cost	49	72
Getting Ontario Connected Act variance	39	24
Distribution rate riders	26	-
Incremental cloud computing implementation costs deferral	20	10
Stock-based compensation	18	24
Excess export service revenue variance	-	18
Other	51	44
Total regulatory assets	3,825	3,503
Less: current portion	(5)	(50)
	3,820	3,453
Regulatory liabilities:		
Post-retirement and post-employment benefits	333	373
Earnings sharing mechanism (ESM) deferral	297	136
Retail settlement variance account (RSVA)	242	157

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

External revenue variance 73 49
Capitalized overhead tax variance 50 38
OPEB asymmetrical carrying charge variance 49 33
Asset removal costs cumulative variance 48 26
Tax rule changes variance 34 33
Pension cost differential 30 21
Advanced Metering Infrastructure (AMI) 2.0 variance 29 7
Distribution rate riders - 45
Other 24 28
Total regulatory liabilities 1,209 946
Less: current portion (224) (132)
985 814

Deferred Income Tax Regulatory Asset

Deferred income taxes are recognized on temporary differences between the carrying amount of assets and liabilities in the financial statements and the corresponding tax bases used in the computation of taxable income. The Company has recognized regulatory assets that correspond to deferred income taxes that flow through the rate-setting process. In the absence of rateregulated accounting, the Company's income tax expense would have been recognized using the liability method and there would be no regulatory accounts established for income taxes to be recovered through future rates.

Broadband Deferral

The Company recognizes the incremental costs and incremental revenues attributable to carrying out activities pertaining to designated broadband projects as defined under the Building Broadband Faster Act (Ontario) in this generic deferral account.

Post-Retirement and Post-Employment Benefits - Non-Service Cost

Hydro One Networks has recorded a regulatory asset relating to the future recovery of its post-retirement and post-employment benefits other than service costs. The regulatory asset includes the applicable tax impact to reflect taxes payable. Prior to adoption of ASU 2017-07 in 2018, these amounts were capitalized to property, plant and equipment and intangible assets. In 2018 and 2019, the OEB approved the regulatory asset for Hydro One Networks' transmission business and distribution business, respectively. As part of Hydro One Networks' 2020-2022 Transmission Decision, the OEB concluded that the nonservice cost component of Hydro One Network's OPEB costs shall be recognized as OM&A for both its transmission and distribution businesses. Furthermore, Hydro One Networks distribution continued to record the non-service cost component of OPEBs in this account until the end of 2022. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were recovered from ratepayers over a one-year period that ended December 31, 2023 and a three-year period that ended December 31, 2025, respectively.

Getting Ontario Connected Act Variance

On October 31, 2023, the OEB issued its Decision and Order approving the establishment of a generic sector-wide variance account, effective April 1, 2023. The account was established to record incremental costs of locating underground infrastructure resulting from the implementation of Provincial legislation: Bill 93, Getting

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

Ontario Connected Act, 2022.

Distribution Rate Riders

As part of the JRAP Decision, the OEB approved the disposition of certain deferral and variance account balances as at December 31, 2020, including accrued interest, which were accumulated in distribution rate riders. The amounts were disposed of over a three-year period that ended December 31, 2025. The balance in the account is mostly comprised of excess returns to be collected from ratepayers in a future rate application.

Incremental Cloud Computing Implementation Costs Deferral

On November 2, 2023, the OEB issued an Accounting Order approving the establishment of a generic sector-wide deferral account, effective December 1, 2023. The account was established to record incremental cloud computing implementation costs.

Stock-based Compensation

The Company recognizes costs associated with share grant plans as a regulatory asset as management considers it probable that share grant plans' costs will be recovered in the future through the rate-setting process. Share grant costs are transferred to labour costs at the time they vest and are issued, and are recovered in rates in accordance with recovery of these labour costs.

Excess Export Service Revenue Variance

The excess export service revenue variance account balance reflects the difference between Hydro One Networks' transmission business' actual export service revenue, and the OEB-approved amounts. As part of the OEB's Decision and Order in the Generic Hearing on Uniform Transmission Rates-Related Issues and the Export Transmission Service Rate, the OEB stated that it considered it appropriate for Hydro One Networks' transmission business to dispose of the balance on an annual basis starting with the 2023 final balance until the effective date of the next transmission rebasing. As a result of this decision, the regulatory asset relating to the excess export service revenues was separately presented from the External Revenue Variance Account for the prior year. On December 11, 2024, as part of the Decision and Order on 2025 transmission rates, the OEB approved the disposition of Hydro One Networks' transmission business' account balance as at December 31, 2023, including accrued interest, over a one-year period that ended December 31, 2025. The regulatory liability balance as at December 31, 2025 was $1million.

Post-Retirement and Post-Employment Benefits

In accordance with OEB rate orders, post-retirement and post-employment benefits costs are recovered on an accrual basis. The Company recognizes the net unfunded or funded status of post-retirement and post-employment obligations on the consolidated balance sheets with an incremental offset to the associated regulatory asset or regulatory liability, as the case may be. A regulatory asset or regulatory liability is recognized because management considers it to be probable that post-retirement and post-employment benefit costs will be recovered or returned in the future through the rate-setting process. The post-retirement and post-employment benefit obligation is remeasured to the present value of the actuarially determined benefit obligation at each year end based on an annual actuarial report, with an offset to the associated regulatory asset or regulatory liability, as the case may be, to the extent of the remeasurement adjustment.

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

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Notes to the financial statements

ESM Deferral
In March 2019, the OEB approved the establishment of an ESM deferral account for Hydro One Networks' distribution segment to record over-earnings including tax impacts. Under this mechanism, Hydro One shares 50% of regulated earnings that exceed the OEB-approved regulatory return-on-equity (ROE) by more than 100 basis points with distribution ratepayers. A similar account was approved for Hydro One Networks' transmission segment in April 2020. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' distribution business' balance as at December 31, 2020, including accrued interest, over a three-year period that ended December 31, 2025. The OEB also approved the disposition of the ESM account balances as at December 31, 2024 in Hydro One Networks' distribution and transmission businesses' 2026 rates application on a final basis, including accrued interest, over a one-year period ending December 31,2026.
RSVA
Hydro One has deferred certain retail settlement variance amounts under the provisions of Article 490 of the OEB's Accounting Procedures Handbook. The RSVA account tracks the difference between the cost of power purchased from the IESO and the cost of power recovered from ratepayers. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' distribution business' balance as at December 31, 2020, including accrued interest, over a three-year period that ended December 31, 2025. In December 2024, as part of the Decision and Order on 2025 distribution rates, the OEB approved, on an interim basis, the disposition of certain RSVA balances as at December 31, 2023, including accrued interest, over a one-year period that ended December 31, 2025. This disposition became final upon receipt of the Decision and Order on 2026 distribution rates issued in December 2025. The OEB also approved disposition of certain RSVA balances as at December 31, 2024, including accrued interest, over a one-year period ending December 31, 2026 on both aninterim and final basis.
External Revenue Variance
The external revenue variance account balance reflects the difference between Hydro One Networks' transmission business' actual external revenues from secondary land use and the OEB-approved amounts. The account also records the difference between actual net external station maintenance, engineering and construction services revenue, and other external revenue,and the OEB-approved amounts.
Capitalized Overhead Tax Variance
As part of the JRAP Decision, the OEB approved the establishment of a capitalized overhead tax variance account to capture the difference between the capitalized overheads deducted in calculating the regulatory tax expense included in rates and the actual capitalized overhead costs deducted in Hydro One's tax returns for Hydro One Networks' transmission and distribution businesses for the 2016 to 2027 period. Variance amounts are recognized at the earlier of (i) when the tax year has been audited by the Canada Revenue Agency or (ii) when the taxation year is statute barred.
OPEB Asymmetrical Carrying Charge Variance
On September 14, 2017, the OEB issued its Report of the Board: Regulatory Treatment of Pension and OPEB Costs that

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

allowed rate-regulated utilities to track the difference between their pension and OPEB costs calculated under the accrual method and the cash payment method, effective January 1, 2018, and record the carrying charges associated with the balance on an asymmetrical basis. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a one-year period that ended December 31, 2023, and a three-year period that ended December 31, 2025, respectively. As part of the same decision, the OEB approved the modification of this account for both Hydro One Networks' transmission and distribution businesses for 2023 to 2027.

Asset Removal Costs Cumulative Variance

In April 2020, the OEB approved the establishment of an asset removal costs cumulative variance account for Hydro One Networks' transmission business to record the difference between the revenue requirement associated with forecast asset removal costs included in depreciation expense and actual asset removal costs. This account is asymmetrical to the benefit of ratepayers on a cumulative basis over the approved rate term. As part of the JRAP Decision received in November 2022, the OEB approved the continuance of this account for Hydro One Networks' transmission business and the establishment of this account for Hydro One Networks' distribution business for 2023 to 2027.

Tax Rule Changes Variance

The 2019 federal and Ontario budgets (Budgets) provided certain time-limited investment incentives permitting Hydro One Networks to deduct accelerated capital cost allowance of up to three times the first-year rate for capital investments acquired after November 20, 2018 and placed in-service before January 1, 2028 (Accelerated Depreciation). Following the enactment of the Budget measures in the second quarter of 2019, the OEB directed all Ontario regulated utilities including Hydro One Networks to track the full revenue impact of the tax benefits related to the Accelerated Depreciation rules to ratepayers. The tax benefit to be returned to ratepayers in the future gave rise to a regulatory liability and resulted in a decrease in revenues as current rates do not include the benefit of the Accelerated Depreciation; therefore, the revenue subject to refund cannot be recognized. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a one-year period that ended December 31, 2023 and a three-year period that ended December 31,2025, respectively.

Pension Cost Differential

Variances between the OM&A pension cost recognized, and the cost embedded in rates as part of the rate-setting process for Hydro One Networks' transmission and distribution businesses are recognized as a regulatory asset or regulatory liability, as the case may be. As part of the JRAP Decision received in November 2022, the OEB approved the disposition of Hydro One Networks' transmission and distribution account balances as at December 31, 2020, including accrued interest, which were returned to ratepayers over a one-year period that ended December 31, 2023

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and a three-year period that ended December 31,2025, respectively.
AMI 2.0 Variance
As part of the JRAP Decision, the OEB approved the establishment of the AMI 2.0 variance account. The account records the
difference in revenue requirement impact including tax, if any, between the planned in-service additions included in the
forecasted costs of the AMI 2.0 program over the 2023-2027 period and the actual in-service additions achieved as part of the
AMI 2.0 program over the 2023-2027 period. The account is asymmetrical to the benefit of ratepayers.
10. INVESTMENTS IN SUBSIDIARIES

As at December 31 (millions of dollars)	2025	2024
Investment in HOSSM	225	225
Investment in B2M Limited Partnership (B2M LP)	138	138
Investment in CLLP	65	81
Investment in Niagara Reinforcement Limited Partnership (NRLP)	27	27
	455	471

Investment in CLLP
On December 17, 2024, assets related to the Chatham x Lakeshare Transmission Line were transferred from Hydro One
Networks to CLLP for $203 million in return for cash consideration of $122 million and CLLP partnership units totalling $81million.
Effective June 1, 2025, Hydro One Networks sold 10% equity interest to Deshkan Ziibiing Chippewas of the Thames First Nation
for cash consideration of $8 million. Effective July 1, 2025, Hydro One Networks sold an additional 10% equity interest to
Southwest Indigenous Transmission Limited Partnership, owned by the Caldwell First Nation, for cash consideration of
$8 million. The total consideration of $16 million represents the fair value of the equity interest acquired. Following these
transactions, Hydro One's interest in the equity portion of CLLP partnership units was reduced to 80%.
11. OTHER LONG-TERM ASSETS

As at December 31 (millions of dollars)	2025	2024
Right-of-Use assets	34	43
Cloud Computing Implementation Cost	43	35
Investments in associates[1]	261	-
Other long-term assets	5	9
	343	87

1 On March 4, 2025, Hydro One Networks completed the acquisition of an approximate 48% interest in the EWT LP for approximately $261 million in cash, includingclosing adjustments.
12. ACCOUNTS PAYABLE AND OTHER CURRENT LIABILITIES

As at December 31 (millions of dollars)	2025	2024
Accrued liabilities	901	716
Accounts payable	351	329
Unearned revenue	312	335
Regulatory liabilities (Note 9)	224	132
Accrued interest (Note 20)	209	185
Lease obligations	11	12
Derivative liability	4	4
Environmental liabilities (Note 16)	2	7
	2,014	1,720

13. OTHER LONG-TERM LIABILITIES

As at December 31 (millions of dollars)	2025	2024
Post-retirement and post-employment benefit liability (Note 15)	1,633	1,556

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Lease obligations 23 32
Long-term accounts payable and other liabilities 23 27
Asset retirement obligations (Note 17) 23 19
Long-term inter-company payable (Note 20) 14 21
Environmental liabilities (Note 16) 1 2
Derivative liability - 3
1,717 1,660
14. DEBT
Hydro One issues notes for long-term financing under its Medium-Term Note (MTN) Program. The terms of certain issuances are mirrored down to Hydro One Networks through the issuance of inter-company debt. In addition, long-term debt includes $229 million payable to Hydro One transferred to Hydro One Networks from Hydro One in 2018, maturing on December 31, 2026. The following table presents long-term debt outstanding at December 31, 2025 and 2024:As at December 31 (millions of dollars) 2025 2024
Long-term debt 18,193 16,517
Add: Net unamortized debt premiums 34 37
Add: Realized mark-to-market gain1 - 3
Less: Deferred debt issuance costs (64) (57)
Less: Long-term debt payable within one year (1,144) (1,253)
Long-term debt 17,019 15,247
1 In October 2023, Hydro One entered into $400 million fixed-to-floating interest-rate swap agreement to convert the $400 million Medium Term Note (MTN) Series 57 notes matured October 20, 2025, into a variable rate debt. This swap was accounted for as a fair value hedge. In December 2023, this swap was terminated with a payment received of $6 million on settlement, which is being amortized over the term of the related note, and the same amount is mirrored down to Hydro One Networks.
In 2025, Hydro One issued $2,700 million long-term debt under its MTN Program (2024 - $2,750 million), of which $2,700 million was mirrored down to Hydro One Networks.
In 2025, Hydro One repaid $1,150 million (2024 - $700 million) of maturing long-term debt under its MTN Program. Hydro One Networks repaid inter-company debt of $1,024 million (2024 - $700 million) to Hydro One.
Inter-company Demand Loan
On June 1, 2021, Hydro One Networks issued a $29 million non-interest bearing demand promissory note to Orillia Power Distribution Corporation (Orillia Power) in exchange for the assets of Orillia Power. In 2024, the note was reduced by $2 million through an offset of the inter-company demand facility. As at December 31, 2025 and 2024, $27 million of the promissory note was outstanding. During the years ended December 31, 2025 and 2024, no promissory notes were issued.
15. PENSION AND POST-RETIREMENT AND POST-EMPLOYMENT BENEFITS
Hydro One has a Pension Plan, a supplementary pension plan (Supplementary Plan), and post-retirement and post-employment benefit plans (Benefit Plans), and a DC Plan.
Pension Plan and Supplementary Plan
The Pension Plan is a defined benefit contributory plan which covers eligible regular employees of Hydro One and its subsidiaries. The Pension Plan provides benefits based on highest three-year average pensionable earnings up to March 31,

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2025. Beginning April 1, 2025, all service for all groups on a go-forward basis will be calculated using the highest five-year average pensionable earnings. For management employees who commenced employment on or after January 1, 2004, and for the Society of United Professionals (Society)-represented staff hired after November 17, 2005, benefits are based on the highest five-year average pensionable earnings for all their service. After retirement, pensions are indexed to inflation. Membership in the Pension Plan was closed to management employees who were not eligible to join the Pension Plan as of September 30, 2015.
These employees are eligible to join the DC Plan.
Company and employee contributions to the Pension Plan are based on actuarial reports, including valuations performed at least every three years, and actual or projected levels of pensionable earnings, as applicable. The most recent actuarial valuation was performed effective December 31, 2024 and filed on September 23, 2025. Total annual cash Pension Plan employer contributions for 2025 were $68 million (2024 - $75 million). Estimated annual Pension Plan employer contributions for the years 2026, 2027, 2028, 2029, and 2030 are approximately $70 million, $73 million, $77 million, $81 million, and $85 million,respectively.
The Supplementary Plan provides members of the Pension Plan with benefits that would have been earned and payable under the Pension Plan beyond the limitations imposed by the Income Tax Act (Canada). The Supplementary Plan obligation is included with other post-retirement and post-employment benefit obligations on the balance sheets.
At December 31, 2025, the present value of Hydro One's projected pension benefit obligation was estimated to be $8,907 million (2024 - $8,686 million). The fair value of pension plan assets available for these benefits was $9,517 million (2024 - $9,333million).
Post-Retirement and Post-Employment Plans
The Company accounts for post-retirement and post-employment costs consistent with their inclusion in OEB-approved rates.
During the year ended December 31, 2025, $124 million (2024 - $109 million) were attributable to labour, of which $83 million (2024 - $70 million) were charged to operations, and $41 million (2024 - $39 million) was capitalized as part of the cost of property, plant and equipment and intangible assets. Benefits paid in 2025 were $73 million (2024 - $71 million).
The Company presents its post-retirement and post-employment benefit liabilities on its balance sheets as follows:

As at December 31 (millions of dollars)	2025	2024
Accrued liabilities	76	74
Post-retirement and post-employment benefit liability	1,633	1,556
Net unfunded status	1,709	1,630

DC Plan
Hydro One established a DC Plan effective January 1, 2016. The DC Plan covers eligible management employees hired on or after January 1, 2016, as well as management employees hired before January 1, 2016 who were not eligible to join the Pension Plan as of September 30, 2015. Members of the DC Plan have an option to contribute 4%, 5% or 6% of their pensionable earnings, with matching contributions by Hydro One up to an annual contribution limit. There is also a Supplementary Notional Plan that provides members of the DC Plan with employer contributions beyond

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the limitations imposed by the Income Tax Act
(Canada) in the form of credits to a notional account. Hydro One Networks
contributions to the DC Plan for the year ended
December 31, 2025 were $5 million (2024 - $4 million).
16. ENVIRONMENTAL LIABILITIES
The following tables show the movements in environmental liabilities for the
years ended December 31, 2025 and 2024:
Year ended December 31, 2025 (millions of dollars) PCB LAR Total
Environmental liabilities - beginning 6 3 9
Expenditures (4) (1) (5)
Revaluation adjustment (1) - (1)
Environmental liabilities - ending 1 2 3
Less: current portion (1) (1) (2)
- 1 1
Year ended December 31, 2024 (millions of dollars) PCB LAR Total
Environmental liabilities - beginning 39 4 43
Expenditures (34) (1) (35)
Revaluation adjustment 1 - 1
Environmental liabilities - ending 6 3 9
Less: current portion (6) (1) (7)
- 2 2
At December 31, 2025, the estimated future environmental expenditures were as
follows:(millions of dollars)
2026 2
2027 1
Thereafter -
3
There are uncertainties in estimating future environmental costs due to
potential external events such as changes in legislation
or regulations, and advances in remediation technologies. In determining the
amounts to be recorded as environmental liabilities,
the Company estimates the current cost of completing required work and makes
assumptions as to when the future expenditures
will actually be incurred, in order to generate future cash flow information.
All factors used in estimating the Company's
environmental liabilities represent management's best estimates of the
present value of costs required to meet existing
legislation or regulations. However, it is reasonably possible that numbers
or volumes of contaminated assets, cost estimates to
perform work, inflation assumptions and the assumed pattern of annual cash
flows may differ significantly from the Company's
current assumptions. In addition, with respect to the PCB environmental
liability, the availability of critical resources such as
skilled labour and replacement assets and the ability to take maintenance
outages in critical facilities may influence the timing ofexpenditures.
PCBs
Environment and Climate Change Canada regulations, enacted under the Canadian
Environmental Protection Act, 1999, govern
the management, storage and disposal of PCBs based on certain criteria,
including type of equipment, in-use status, and PCBcontamination
thresholds. Under previous regulations, the Company's PCBs were to be
disposed of by the end of 2025, with the
exception of specifically exempted equipment. On December 31st, 2025,
regulations amending the Canadian Environmental
Protection Act, 1999 were published in the Canada Gazette, Part II. The
amendments include deferring the end-of-use deadline

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for certain PCB-containing electrical equipment from December 31, 2025 to December 31, 2026. Contaminated equipment will generally be replaced, or will be decontaminated by removing PCB-contaminated insulating oil and retro filling with replacement oil that contains PCBs in concentrations of less than two parts per million. As at December 31, 2025, the Company's best estimate of the total future expenditures to comply with current PCB regulations was $1 million (2024 - $6 million). These expenditures are expected to be incurred in 2026. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment in 2025 to decrease the PCB environmental liability by $1 million (2024 - increase of $1 million).

LAR

As at December 31, 2025, the Company's best estimate of the total future expenditures to complete its LAR program was $2 million (2024 - $3 million). These expenditures are expected to be incurred over the period from 2026 to 2028. As a result of its annual review of environmental liabilities, the Company recorded a revaluation adjustment that was less than $1 million in 2025 to the LAR environmental liability (2024 - $nil).

17. ASSET RETIREMENT OBLIGATIONS

Hydro One Networks records a liability for the estimated future expenditures for the removal and disposal of asbestos-containing materials installed in some of its facilities. Asset retirement obligations, which represent legal obligations associated with the retirement of certain tangible long-lived assets, are computed as the present value of the projected expenditures for the future retirement of specific assets and are recognized in the period in which the liability is incurred, if a reasonable estimate can be made. If the asset remains in service at the recognition date, the present value of the liability is added to the carrying amount of the associated asset in the period the liability is incurred and this additional carrying amount is depreciated over the remaining life of the asset. If an asset retirement obligation is recorded in respect of an out-of-service asset, the asset retirement cost is charged to results of operations. Subsequent to the initial recognition, the liability is adjusted for any revisions to the estimated future cash flows associated with the asset retirement obligation, which can occur due to a number of factors including, but not limited to, cost escalation, changes in technology applicable to the assets to be retired, changes in legislation or regulations, as well as for accretion of the liability due to the passage of time until the obligation is settled. Depreciation expense is adjusted prospectively for any increases or decreases to the carrying amount of the associated asset.

Some of the Company's transmission and distribution assets, particularly those located on unowned easements and rights-ofway, may have asset retirement obligations, conditional or otherwise. The majority of the Company's easements and rights-ofway are either of perpetual duration or are automatically renewed annually. Land rights with finite terms are generally subject to extension or renewal. As the Company expects to use the majority of its facilities in perpetuity, no asset retirement obligations have been recorded for these assets. If, at some future date, a particular facility is shown not to meet the perpetuity assumption, it will be reviewed to determine whether an estimable asset retirement

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obligation exists. In such a case, an asset retirement
obligation would be recorded at that time.
In determining the amounts to be recorded as asset retirement obligations,
the Company estimates the current fair value for
completing required work and makes assumptions as to when the future
expenditures will actually be incurred, in order to
generate future cash flow information. A long-term inflation assumption of
approximately 2% has been used to express these
current cost estimates as estimated future expenditures. Future expenditures
have been discounted using factors ranging from
approximately 1.0% to 3.0% (2024 - 1.0% to 3.0%), depending on the
appropriate rate for the period when expenditures are
expected to be incurred. All factors used in estimating the Company's asset
retirement obligations represent management's best
estimates of the cost required to meet existing legislation or regulations.
However, it is reasonably possible that numbers or
volumes of contaminated assets, cost estimates to perform work, inflation
assumptions and the assumed pattern of annual cash
flows may differ significantly from the Company's current assumptions. Asset
retirement obligations are reviewed annually or
more frequently if significant changes in regulations or other relevant
factors occur. Estimate changes are accounted for
prospectively. As a result of its annual review of asset retirement
obligations, there was an increase of $3 million to the asset
retirement obligations recorded in 2025 (2024 - $nil).
As at December 31, 2025, Hydro One Networks had recorded total asset
retirement obligations of $23 million (2024 - $19
million), primarily consisting of the estimated future expenditures
associated with the removal and disposal of asbestoscontaining
materials installed in some of its facilities.
18. SHARE CAPITAL
Common Shares
Hydro One Networks is authorized to issue an unlimited number of common and
preferred shares. At December 31, 2025 and
2024, Hydro One Networks had 209,401,290 common shares issued and outstanding
and no preferred shares issued andoutstanding.
During 2025, Hydro One Networks declared common share dividends in the amount
of $792 million (2024 - $753 million) toHydro One.
19. STOCK-BASED COMPENSATION
The following compensation plans were established by Hydro One Limited,
however they represent components of
compensation costs of Hydro One and its subsidiaries, including Hydro One
Networks, in current and future periods.Share Grant Plans
Hydro One Limited has two share grant plans (Share Grant Plans), one for the
benefit of certain members of the Power Workers'
Union (PWU) (PWU Share Grant Plan) and one for the benefit of certain members
of the Society (Society Share Grant Plan).
Hydro One and Hydro One Limited entered into an intercompany agreement, such
that Hydro One will pay Hydro One Limited for
the compensation costs associated with these plans. The agreement requires
Hydro One Networks to reimburse Hydro One for
the value of shares granted to the Company's eligible employees relating to
these plans.
The PWU Share Grant Plan provides for the issuance of common shares of Hydro
One Limited from treasury to certain eligible
members of the PWU annually, commencing on April 1, 2017 and continuing until

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the earlier of April 1, 2028 or the date an
eligible employee no longer meets the eligibility criteria of the PWU Share
Grant Plan. To be eligible, an employee must be a
member of the Pension Plan on April 1, 2015, be employed on the date annual
share issuance occurs and continue to have
under 35 years of service. The requisite service period for the PWU Share
Grant Plan began on July 3, 2015, which is the date
the share grant plan was ratified by the PWU. The number of common shares
issued annually to each eligible employee will be
equal to 2.7% of such eligible employee's salary as at April 1, 2015, divided
by $20.50, being the price of the common shares of
Hydro One Limited in the Initial Public Offering (IPO). The aggregate number
of Hydro One Limited common shares issuable
under the PWU Share Grant Plan shall not exceed 3,981,763 common shares. In
2015, 3,913,671 Hydro One Limited common
shares were granted under the PWU Share Grant Plan relevant to the total
stock-based compensation recognized by Hydro OneNetworks.
The Society Share Grant Plan provides for the issuance of common shares of
Hydro One Limited from treasury to certain eligible
members of the Society annually, commencing on April 1, 2018 and continuing
until the earlier of April 1, 2029 or the date an
eligible employee no longer meets the eligibility criteria of the Society
Share Grant Plan. To be eligible, an employee must be a
member of the Pension Plan on September 1, 2015, be employed on the date
annual share issuance occurs and continue to
have under 35 years of service. Therefore the requisite service period for
the Society Share Grant Plan began on September 1,
2015. The number of common shares issued annually to each eligible employee
will be equal to 2.0% of such eligible employee's
salary as at September 1, 2015, divided by $20.50, being the price of the
common shares of Hydro One Limited in the IPO. The
aggregate number of Hydro One Limited common shares issuable under the
Society Share Grant Plan shall not exceed
1,434,686 common shares. In 2015, 1,352,503 Hydro One Limited common shares
were granted under the Society Share Grant
Plan relevant to the total stock-based compensation recognized by Hydro One
Networks.
The fair value of the Hydro One Limited 2015 share grants to employees of
Hydro One Networks was $108 million. The fair value
was estimated based on the grant date Hydro One Limited share price of $20.50
and is recognized using the graded-vesting
attribution method as the share grant plans have both a performance condition
and a service condition. In 2025, 326,300
common shares of Hydro One Limited were issued under the Share Grant Plans
(2024 - 339,117) to eligible employees of Hydro
One Networks. Total stock-based compensation recognized by Hydro One Networks
during 2025 was $1 million (2024 - $2
million) and was recorded as a regulatory asset.
A summary of Hydro One Networks' share grant activity under the Share Grant
Plans during the years ended December 31,2025 and 2024 is presented below:
Year ended December 31, 2025
Share Grants
(number of common shares)
Weighted-Average
Price
Share grants outstanding - beginning 1,366,281 $20.50

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Vested and issued1 (326,300) -
Forfeited (44,977) $20.50
Share grants outstanding - ending 995,004 $20.50
1 In 2025, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.
Year ended December 31, 2024
Share Grants
(number of common shares)
Weighted-Average
Price
Share grants outstanding - beginning 1,731,758 $20.50
Granted 1,092 -
Vested and issued1 (339,117) -
Forfeited (27,452) $20.50
Share grants outstanding - ending 1,366,281 $20.50
1 In 2024, Hydro One Limited issued common shares from treasury to eligible Hydro One Networks employees in accordance with provisions of the Share Grant Plans. In accordance with the intercompany agreement between Hydro One and Hydro One Limited, Hydro One Networks made payments to Hydro One for the common shares issued.
Directors' DSU Plan
Under the Directors' DSU Plan, directors can elect to receive credit for their annual cash retainer in a notional account of DSUs in lieu of cash. Hydro One Limited Board of Directors may also determine from time to time that special circumstances exist that would reasonably justify the grant of DSUs to a director as compensation in addition to any regular retainer or fee to which the director is entitled. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue Hydro One Limited common share dividend equivalents in the form of additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.
During 2025 and 2024, Directors' DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks were asfollows:
Year ended December 31 (number of DSUs) 2025 2024
DSUs outstanding - beginning 67,271 58,866
Granted 13,951 14,787
Settled (17,294) (6,382)
DSUs outstanding - ending 63,928 67,271
For the years ended December 31, 2025 and 2024, an expense recognized in earnings with respect to the Directors' DSU Plan was $1 million. At December 31, 2025, a liability of $4 million (2024 - $3 million) related to Directors' DSUs has been recorded at the closing price of Hydro One Limited common shares of $54.64. This liability is included in other long-term liabilities on thebalance sheets.
Management DSU Plan
Under the Management DSU Plan, eligible executive employees can elect to receive a specified proportion of their annual shortterm incentive in a notional account of DSUs in lieu of cash. Each DSU represents a unit with an underlying value equivalent to the value of one common share of Hydro One Limited and is entitled to accrue common share dividend equivalents in the form of

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additional DSUs at the time dividends are paid, subsequent to declaration by Hydro One Limited Board of Directors.

During 2025 and 2024, Management DSU Plan awards granted by Hydro One Limited that related to Hydro One Networks wereas follows:

Year ended December 31 (number of DSUs)	2025	2024
DSUs outstanding - beginning	47,757	51,102
Granted	7,751	8,812
Paid	(4,118)	(12,157)
DSUs outstanding - ending	51,390	47,757

For the year ended December 31, 2025 and 2024, an expense recognized in earnings with respect to the Management DSU Plan was less than $1 million. At December 31, 2025, a liability of $3 million (2024 - $2 million) related to Management DSUs has been recorded at the closing price of Hydro One Limited common shares of $54.64. This liability is included in other long-term liabilities on the balance sheets.

Employee Share Ownership Plan

In 2015, Hydro One Limited established Employee Share Ownership Plans (ESOP) for certain eligible management and nonrepresented employees (Management ESOP) and for certain eligible Society-represented staff (Society ESOP). Under the Management ESOP, the eligible management and non-represented employees may contribute between 1% and 6% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 50% of their contributions, up to a maximum Company contribution of $25,000 per calendar year. Under the Society ESOP, the eligible Society-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One Limited. The Company matches 25% of their contributions, with no maximum Company contribution per calendar year.

In 2024, Hydro One established ESOP for certain eligible PWU represented staff (PWU ESOP). Under the PWU ESOP, the eligible PWU-represented staff may contribute between 1% and 4% of their base salary towards purchasing common shares of Hydro One. The Company matches 33% of their contribution, with no maximum Company contribution per calendar year. In 2025, Company contributions made under the ESOP were $9 million (2024 - $5 million).

LTIP

Effective August 31, 2015, the Board of Directors of Hydro One adopted an LTIP. Under the LTIP, long-term incentives were granted to certain executive and management employees of Hydro One and its subsidiaries, and all equity-based awards would either be settled in newly issued shares of Hydro One from treasury or cash, subject to Hydro One's discretion, consistent with the provisions of the plan which also permit the participants to surrender a portion of their awards to satisfy related withholding taxes requirements. The aggregate number of shares issuable under the LTIP shall not exceed 11,900,000 shares of Hydro One.

The LTIP provides flexibility to award a range of vehicles, including Performance Share Units (PSUs), RSUs, stock options, share appreciation rights, restricted shares, DSUs, and other share-based awards. The mix of vehicles is intended to vary by role to recognize the level of executive accountability for overall business performance.

PSUs and RSUs

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A summary of PSU and RSU awards activity under the LTIP during the years ended December 31, 2025 and 2024 is presentedbelow:

PSUs RSUs

Year ended December 31 (number of units) 2025 2024 2025 2024

Units outstanding - beginning 127,592 64,387 260,547 151,142

Granted 75,440 69,189 126,051 126,034

Forfeited (27,792) (4,380) (43,008) (14,208)

Vested and issued (16,877) (1,604) (20,493) (2,421)

Units outstanding - ending 158,363 127,592 323,097 260,547

To comply with the Accountability Act and the OEB Act, in 2019 Hydro One Limited removed all executive-related compensation from the labour costs of its regulated subsidiaries. During the years ended December 31, 2025 and 2024, no executive-related stock-based compensation was allocated to the regulated businesses of Hydro One Networks.

The grant date total fair value of the awards granted during the year ended December 31, 2025 was $10 million (2024 - $8 million). The compensation expense related to the PSU and RSU awards recognized by the Company during 2025 was $7 million (2024 - $7 million). At December 31, 2025, $3 million (2024 - $1 million) payable relating to PSU awards was included in due to related parties on the balance sheets.

20. RELATED PARTY TRANSACTIONS

The Company is indirectly owned by Hydro One Limited. The Province of Ontario is a shareholder of Hydro One Limited with approximately 47.1% ownership at December 31, 2025. The Ministry of Energy and Mines (Ministry) and the Ministry of Infrastructure (MOI) are related parties to Hydro One because they are controlled by the Province. The IESO, Ontario Power Generation Inc. (OPG), Ontario Electricity Financial Corporation (OEFC), and the OEB are related parties to Hydro One Networks because they are controlled or significantly influenced by the Ministry. B2M LP, NRLP and CLLP are subsidiaries of Hydro One Networks, HOSSM is a subsidiary of Hydro One, and Acronym Solutions Inc. (Acronym) is a subsidiary of Hydro One Limited. The following is a summary of the Company's related party transactions during the years ended December 31, 2025 and 2024:

Year ended December 31 (millions of dollars)

Related Party Transaction 2025 2024

Ministry Broadband subsidy1 27 -

MOI Broadband subsidy1 19 43

IESO

Power purchased 2,999 2,677

Revenues for transmission services2 2,271 2,162

Amounts related to electricity rebates 1,104 1,164

Distribution revenues related to rural rate protection 256 255

Funding received related to CDM programs - 1

OPG

Power purchased 23 18

Revenues related to provision of services and supply of electricity 10 7

Capital contribution received from OPG 20 3

Costs related to the purchase of services 1 1

OEFC Power purchased from power contracts administered by the OEFC 2 1

OEB OEB fees 14 12

Hydro One

Dividends paid 792 753

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Notes to the financial statements

Interest expense on long-term debt 741 682
Interest (income) expense on inter-company demand facility 7 (1)
Stock-based compensation costs 8 9
Services received - costs expensed 7 6
B2M LP Revenues for services provided 2 1
Distributions and cash advances received 20 16
HOSSM Revenues for services provided 79 72
Distributions received 14 10
Acronym Services received - costs expensed 32 33
Revenues for services provided 6 3
NRLP Distributions and cash advances received 3 3
Revenues for services provided 1 1
CLLP Transfer of assets - 203
Receipt of partnership units - 81
Cash received from sale of assets - 122
Distributions and cash advances received 8 -
Revenues for services provided 4 -
Hydro One Limited and its other
subsidiaries
Revenues for services provided 2 3
Services received - costs expensed (recovered) - 1
1 On October 31, 2024, the MOI announced that it has developed a program to deliver up to $400 million in subsidies to internet service providers (ISPs) for work
associated with designated broadband projects. The program is intended to enable ISPs to successfully and safely attach their material and equipment to theCompany's poles to bring connectivity to rural communities as part of a designated broadband project as defined under Building Broadband Faster Act (Ontario). A
portion of these subsidies is used to reimburse Hydro One Networks on behalf of ISPs for their share of enablement costs incurred to facilitate the program to date.
During 2025, Ministry replaced MOI in making broadband subsidy payments to Hydro One.
2 Consistent with the Company's revenue recognition policy, the Company recognized revenues of $2,273 million in 2025 (2024 - $2,145 million).
Sales to and purchases from related parties are based on the requirements of the OEB's Affiliate Relationships Code.
Outstanding balances at period end are interest-free and settled in cash.
Invoices are issued monthly, and amounts are due andpaid on a monthly basis.
The amounts due to and from related parties at December 31, 2025 and 2024 are as follows:As at December 31 (millions of dollars) 2025 2024
Due from related parties 385 302
Long-term inter-company payable (14) (21)
Accrued interest (209) (185)
Due to related parties (478) (341)
Inter-company demand promissory note (27) (27)
Inter-company demand facility 789 663
Long-term debt, including current portion (18,163) (16,500)
21. STATEMENTS OF CASH FLOWS
The changes in non-cash balances related to operations consist of the following:Year ended December 31 (millions of dollars) 2025 2024
Accounts receivable (159) (91)
Due from related parties (83) (5)
Materials and supplies - 5
Other assets (2) (53)

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

General Index of Financial Information

Notes to the financial statements

Accounts payable 22 93
Accrued liabilities 130 32
Unearned revenue (23) 123
Due to related parties 136 43
Accrued interest 24 34
Long-term accounts payable and other liabilities (4) 2
Post-retirement and post-employment benefit liability 60 46
101 229
Capital Expenditures
The following tables reconcile investments in property, plant and equipment and intangible assets and the amounts presented in the statements of cash flows for the years ended December 31, 2025 and 2024. The reconciling items include net change in accruals and capitalized depreciation.
Year ended December 31, 2025 (millions of dollars)
Property,
Plant and
Equipment
Intangible
Assets Total
Capital investments (3,183) (77) (3,260)
Reconciling items 317 (3) 314
Cash outflow for capital expenditures (2,866) (80) (2,946)
Year ended December 31, 2024 (millions of dollars)
Property,
Plant and
Equipment
Intangible
Assets Total
Capital investments (2,872) (92) (2,964)
Reconciling items 247 7 254
Cash outflow for capital expenditures (2,625) (85) (2,710)
Capital Contributions
Hydro One Networks enters into contracts governed by the OEB Transmission System Code when a transmission customer requests a new or upgraded transmission connection. The customer is required to make a capital contribution to Hydro One Networks based on the shortfall between the present value of the costs of the connection facility and the present value of revenues. The present value of revenues is based on an estimate of load forecast for the period of the contract with Hydro One Networks. Once the connection facility is commissioned, in accordance with the OEB Transmission System Code, Hydro One Networks will periodically reassess the estimated load forecast which will lead to a decrease, or an increase in the capital contributions from the customer. The increase or decrease in capital contributions is recorded directly to property, plant and equipment in service. In 2025, there were $3 million capital contributions from these assessments (2024 - $2 million).
Supplementary Information
Year ended December 31 (millions of dollars) 2025 2024
Net interest paid 717 648
Income taxes paid 36 27

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Assets – lines 1000 to 2599

1060	1,119,000,000	1061	-57,000,000	1120	26,000,000
1400	385,000,000	1401	789,000,000	1480	87,000,000
1599	2,349,000,000	1900	42,382,000,000	1901	-14,770,000,000
1920	2,477,000,000	2008	44,859,000,000	2009	-14,770,000,000
2010	1,612,000,000	2011	-963,000,000	2012	217,000,000
2178	1,829,000,000	2179	-963,000,000	2241	455,000,000
2300	261,000,000	2420	3,902,000,000	2589	4,618,000,000
2599	37,922,000,000				

Liabilities – lines 2600 to 3499

2620	2,013,772,926	2700	1,144,000,000	2860	478,000,000
2861	27,000,000	3139	3,662,772,926	3140	17,019,000,000
3240	1,803,000,000	3320	2,702,000,000	3450	21,524,000,000
3499	25,186,772,926				

Shareholder equity – lines 3500 to 3640

3500	2,934,000,000	3541	5,000,000	3580	-19,000,000
3600	9,815,227,074	3620	12,735,227,074	3640	37,922,000,000

Retained earnings – lines 3660 to 3849

3660	9,288,890,378	3680	1,318,336,696	3701	-792,000,000
3849	9,815,227,074				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Description

Sequence number **0003** 01

Other comprehensive income – lines 7000 to 7020

7020	3,709,572

Revenue – lines 8000 to 8299

8000	8,762,128,544	**8089**	8,762,128,544	**8210**	250,000
8235	60,876,233	**8299**	8,823,254,777		

Cost of sales – lines 8300 to 8519

8320	4,340,672,336	**8518**	4,340,672,336	**8519**	4,421,456,208

Operating expenses – lines 8520 to 9369

8523	21,259,369	**8570**	88,062,452	**8623**	24,612,992
8670	837,714,750	**8710**	689,993,502	**9270**	143,229,935
9284	1,148,350,181	**9367**	2,953,223,181	**9368**	7,293,895,517
9369	1,529,359,260				

Extraordinary items and taxes – lines 9970 to 9999

9970	1,529,359,260	**9990**	133,059,361	**9995**	77,963,203
9998	3,709,572	**9999**	1,322,046,268		

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Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see Guide T4012, T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.
- If you need more space, attach additional schedules.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125			1,322,046,268	A1
Net income (loss) after extraordinary items from line 110 of Schedule 150			0	A2
Total			1,322,046,268	A
Add:				
Provision for income taxes – current	101	133,059,361		
Provision for income taxes – deferred	102	77,963,203		
Interest and penalties on taxes	103	16,347		
Amortization of tangible assets	104	837,714,750		
Amortization of intangible assets	106	88,062,452		
Charitable donations and gifts from Schedule 2	112	1,679,294		
Taxable capital gains from Schedule 6	113	2,547,477		
Non-deductible meals and entertainment expenses	121	10,629,685		
Other reserves on lines 270 and 275 from Schedule 13	125	63,317,591		
Reserves from financial statements – balance at the end of the year	126	2,789,141,221		
Income or loss for tax purposes – partnerships	129	33,341,344		
Subtotal of additions		4,037,472,725 ▶	4,037,472,725	
Add:				
Capital items expensed	206	10,193,080		
Financing fees deducted in books	216	4,908,674		
Recapture of SR&ED expenditures from Form T661	231	2,322,235		

Other additions:

	1 Description 605	2 Amount 295
1	OITC/ORDTC/BCRDTC/ABRDTC/ABIEG from prior year 12(1)(x) ITA	0
2	CCRA true up	3,612,071
3	LTIP not cash settled	601,633
4	Union share grant expenses	1,916,161
5	Asset removal costs	158,969,864
6	Regulatory depreciation	1,527,197
7	Current year Coop underaccrual	283,200
8	Apprenticeship tax credits utilized in prior year	727,063
9	Cloud computing amortization	12,140,312
10	Landscaping cost for land	8,611
	Total of column 2	179,786,112 ▶ 296 179,786,112

Subtotal of other additions	199	197,210,101 ▶	197,210,101	D
Total additions	500	4,234,682,826 ▶	4,234,682,826	
Amount A **plus** line 500			5,556,729,094	B

Deduct:

Gain on disposal of assets per financial statements	401	250,000	
Capital cost allowance from Schedule 8	403	1,861,501,813	
Other reserves on line 280 from Schedule 13	413	76,161,994	
Reserves from financial statements – balance at the beginning of the year	414	2,530,835,954	
Contributions to deferred income plans from Schedule 15	417	41,285,579	
Subtotal of deductions		4,510,035,340 ▶	4,510,035,340

Deduct:

Non-taxable/deductible other comprehensive income items	347	1,815,781	
Book income of partnership	349	60,876,233	

Other deductions:

	1 Description 705	2 Amount 395
1	Deduction under 20(1)(e) ITA	7,770,581
2	Capitalized interest expenses	104,436,929
3	Capitalized overhead (OM&A)	171,850,115
4	Capitalized OPEB expenses	41,133,651
5	Capitalized removal costs - Deducted for tax	18,288,164
6	Prior year Ontario ITC underaccrual	336,188
7	Bond premium amortization (2015 & prior)	511,461
8	S. 18(9.1) ded - debt prepay penalty amort	93,366
9	ARO balance sheet movement	3,199,045
10	Reg asset adjustment	18,051,717
11	Current year OBRI accrual	20,000
12	IRU conversion	2,600,000
13	Reverse hedge gain amortization	2,541,578
	Total of column 2	370,832,795 ▶ 396 370,832,795

Subtotal of other deductions	499	433,524,809 ▶	433,524,809 E
Total deductions	510	4,943,560,149 ▶	4,943,560,149

Net income (loss) for income tax purposes (amount B **minus** line 510) . . . . . 613,168,945 C

Enter amount C on line 300 of the T2 return.

Attached Schedule with Total

Line 206 – Capital items expensed

Title Line 206 – Capital items expensed

Description	Operator (Note)	Amount
Project Cancellation Costs (GL 670000)		10,193,080 00
	+	
	Total	10,193,080 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 216 – Financing fees deducted in books

Title Line 216 – Financing fees deducted in books

Description	Operator (Note)	Amount
Amortization of Underwriting fee (GL #761780)		4,506,791 00
Amortization of Prospectus fee (GL #761790)	+	401,883 00
	Total	4,908,674 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 129 – Income or loss for tax purposes – partnerships

Title Line 129 – Income or loss for tax purposes – partnerships

Explanatory note

Partnership Name: Hydro One Sault Ste Marie Holdings II LP
Partnership Business Number:

Partnership Name: Niagara Reinforcement Limited Partnership
Partnership Business Number:

Partnership Name: B2M Limited Partnership
Partnership Business Number:

Partnership Name: Chatham x Lakeshore Limited Partnership
Partnership Business Number:

Description	Operator (Note)	Amount
HOSSMH II LP Taxable Income - Box 104		18,925,878 00
NRLP LP Taxable Income - Box 104	+	210,158 00
B2M Limited Partnership - Box 104	+	13,403,051 00
Chatham x Lakeshore Limited Partnership - Box 104	+	802,257 00
	+	
	Total	33,341,344 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 347 – Non-taxable/deductible other comprehensive income items

Title Line 347 – Non-taxable/deductible other comprehensive income items

Description	Operator (Note)	Amount
MTN OCI		2,698,379 00
OCI Tax	-	882,598 00
	Total	1,815,781 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 228 – Non-deductible legal and accounting fees

Title Line 228 – Non-deductible legal and accounting fees

Explanatory note

TM {c2}

Description	Operator (Note)	Amount
Non-deductible legal costs		
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Line 239 – Taxable/non-deductible other comprehensive income items

Title Line 239 – Taxable/non-deductible other comprehensive income items

Deduction summary as per paragraph 20(1)(e) of the ITA

Federal

Deduction summary as per paragraph 20(1)(e) of the ITA

Description	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	E Annual deduction (This amount is posted to one of the lines 395 of Schedule 1)	F Balance at the end of the year
1. 2021 Prospectus Fees	2021-06-30	79,953	64,007	15,946	
2. 2021 Underwriting Fees	2021-06-30	4,050,000	3,242,219	807,781	
3. 2022 Prospectus Fees	2022-06-30	166,614	100,060	33,323	33,231
4. 2022 Underwriting Fees	2022-06-30	2,625,000	1,576,438	525,000	523,562
5. 2023 Prospectus Fees	2023-06-30	246,126	98,585	49,225	98,316
6. 2023 Underwriting Fees	2023-06-30	8,712,500	3,489,774	1,742,500	3,480,226
7. 2024 Prospectus Fees	2024-06-30	332,929	66,768	66,586	199,575
8. 2024 Underwriting Fees	2024-06-30	10,818,575	2,169,643	2,163,715	6,485,217
9. 2025 Prospectus Fees	2025-06-30	417,524		83,505	334,019
10. 2025 Underwriting Fees	2025-06-30	11,415,000		2,283,000	9,132,000
	Totals	38,864,221	10,807,494	7,770,581	20,286,146

Deduction as per paragraph 20(1)(e) of the ITA

This workchart allows you to determine the tax deduction as per paragraph 20(1)(e) of the Income Tax Act (ITA). It relates to the expenses of issuing or selling shares, units or interests and expenses of borrowing money.

Ensure that any of these expenses deducted in the financial statements have been added back on line 216, "Financing fees deducted in books," and/or on line 235, "Share issue expense" to Schedule 1, if applicable.

* If the check box was selected, the annual deduction will be equal to the amount in column C.

1 Description: 2021 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2021-06-30	79,953	64,007	15,946	15,991	15,946	

2 Description: 2021 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2021-06-30	4,050,000	3,242,219	807,781	810,000	807,781	

3 Description: 2022 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2022-06-30	166,614	100,060	66,554	33,323	33,323	33,231

4 Description: 2022 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2022-06-30	2,625,000	1,576,438	1,048,562	525,000	525,000	523,562

5 Description: 2023 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2023-06-30	246,126	98,585	147,541	49,225	49,225	98,316

6 Description: 2023 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2023-06-30	8,712,500	3,489,774	5,222,726	1,742,500	1,742,500	3,480,226

7 Description: 2024 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2024-06-30	332,929	66,768	266,161	66,586	66,586	199,575

8 Description: 2024 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2024-06-30	10,818,575	2,169,643	8,648,932	2,163,715	2,163,715	6,485,217

9 Description: 2025 Prospectus Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2025-06-30	417,524		417,524	83,505	83,505	334,019

10 Description: 2025 Underwriting Fees

Subparagraph 20(1)(e)(v) is applicable in the taxation year*	Date of expense	A Expense amount	B Amounts deductible in the preceding taxation years	C Balance before the annual expense (column A minus column B)	D 20 % of amount A x number of days in the taxation year 365 / **365**	E Annual deduction (C or D, whichever is less)*	F Balance at the end of the year (column C minus column E)
☐	2025-06-30	11,415,000		11,415,000	2,283,000	2,283,000	9,132,000

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Schedule 2

Charitable Donations and Gifts

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- For use by corporations to claim any of the following:
  - the eligible amount of charitable donations to qualified donees
  - the Ontario, Nova Scotia, and British Columbia food donation tax credits for farmers
  - the eligible amount of gifts of certified cultural property
  - the eligible amount of gifts of certified ecologically sensitive land or
  - the additional deduction for gifts of medicine made before March 22, 2017
- All legislative references are to the federal Income Tax Act, unless stated otherwise.
- The eligible amount of a gift is the amount by which the fair market value of the gifted property exceeds the amount of an advantage, if any, for the gift.
- The donations and gifts can be carried forward for 5 years except for gifts of certified ecologically sensitive land made after February 10, 2014, which can be carried forward for 10 years.
- Use this schedule to show a transfer of unused amounts from previous years following an amalgamation or the wind-up of a subsidiary as described under subsections 87(1) and 88(1).
- Subsection 110.1(1.2) provides as follows:
  - Where a particular corporation has undergone an acquisition of control, for tax years that end on or after the acquisition of control, no corporation can claim a deduction for a gift made by the particular corporation to a qualified donee before the acquisition of control.
  - If a particular corporation makes a gift to a qualified donee pursuant to an arrangement under which both the gift and the acquisition of control is expected, no corporation can claim a deduction for the gift unless the person acquiring control of the particular corporation is the qualified donee.
- An eligible medical gift made before March 22, 2017, to a qualifying organization for activities outside of Canada may be eligible for an additional deduction. Calculate the additional deduction in Part 5.
- File this schedule with your T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation – Income Tax Guide.

Part 1 – Charitable donations

Charity/Recipient	Amount ($100 or more only)
-	1,404,294
-	100,000
-	75,000
-	100,000
Subtotal	1,679,294
Add: Total donations of less than $100 each	
Total donations in current tax year	1,679,294

Part 1 – Charitable donations

		Federal		Québec	Alberta
Charitable donations at the end of the previous tax year			1A		
Charitable donations expired after five tax years*	239				
Charitable donations at the beginning of the current tax year (amount 1A **minus** line 239)	240				
Charitable donations transferred on an amalgamation or the wind-up of a subsidiary	250				
Total charitable donations made in the current year (include this amount on line 112 of Schedule 1, Net Income (Loss) for Income Tax Purposes)	210	1,679,294		1,679,294	1,679,294
Subtotal (line 250 **plus** line 210)		1,679,294	1B	1,679,294	1,679,294
Subtotal (line 240 **plus** amount 1B)		1,679,294	1C	1,679,294	1,679,294
Adjustment for an acquisition of control	255				
Total charitable donations available (amount 1C **minus** line 255)		1,679,294	1D	1,679,294	1,679,294
Amount applied in the current year against taxable income (cannot be more than amount 2H in Part 2) (enter this amount on line 311 of the T2 return)	260	1,679,294		1,679,294	1,679,294
Charitable donations closing balance (amount 1D **minus** line 260)	280				

The amount of qualifying donations for the Ontario community food program donation tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2013) . . . . . **262** _____

Ontario community food program donation tax credit for farmers (amount on line 262 **multiplied** by 25 %) . . . . . _____ 1

Enter amount 1 on line 420 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Ontario income tax otherwise payable or amount 1. For more information, see section 103.1.2 of the Taxation Act, 2007 (Ontario).

The amount of qualifying donations for the Nova Scotia food bank tax credit for farmers included in the amount on line 260 (for donations made after December 31, 2015) . . . . . **263** _____

Nova Scotia food bank tax credit for farmers (amount on line 263 **multiplied** by 25 %) . . . . . _____ 2

Enter amount 2 on line 570 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the Nova Scotia income tax otherwise payable or amount 2. For more information, see section 50A of the Nova Scotia Income Tax Act.

The amount of qualifying gifts for the British Columbia farmers' food donation tax credit included in the amount on line 260 (for donations made after February 16, 2016, and before January 1, 2027) . . . . . **265** _____

British Columbia farmers' food donation tax credit (amount on line 265 **multiplied** by 25 %) . . . . . _____ 3

Enter amount 3 on line 683 of Schedule 5, Tax Calculation Supplementary – Corporations. The maximum you can claim in the current year is whichever is less: the British Columbia income tax otherwise payable or amount 3. For more information, see section 20.1 of the British Columbia Income Tax Act.

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amounts carried forward – Charitable donations

Year of origin:		Federal	Québec	Alberta
1st prior year	2024-12-31			
2nd prior year	2023-12-31			
3rd prior year	2022-12-31			
4th prior year	2021-12-31			
5th prior year	2020-12-31			
6th prior year*	2019-12-31			
7th prior year	2018-12-31			
8th prior year	2017-12-31			
9th prior year	2016-12-31			
10th prior year	2015-12-31			
11th prior year	2015-11-04			
12th prior year	2015-10-31			
13th prior year	2014-12-31			
14th prior year	2013-12-31			
15th prior year	2012-12-31			
16th prior year	2011-12-31			
17th prior year	2010-12-31			
18th prior year	2009-12-31			
19th prior year	2008-12-31			
20th prior year	2007-12-31			
21st prior year*	2006-12-31			
Total (to line A)				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 2 – Maximum allowable deduction for charitable donations

Net income for tax purposes **(Note 1) multiplied** by 75 % 459,876,709 2A

Taxable capital gains arising in respect of gifts of capital property included in Part 1 **(Note 2)** **225**

Taxable capital gain in respect of a disposition of a non-qualifying security under subsection 40(1.01) **227**

The amount of the recapture of capital cost allowance in respect of charitable donations **230**

Proceeds of disposition, **less** outlays and expenses **(Note 2)** 2B

Capital cost **(Note 2)** 2C

Amount 2B or 2C, whichever is less **235**

Amount on line 230 or 235, whichever is less 2D

Subtotal (**add** lines 225, 227, and amount 2D) 2E

Amount 2E **multiplied** by 25 % 2F

Subtotal (amount 2A **plus** amount 2F) 459,876,709 2G

Maximum allowable deduction for charitable donations
(enter amount 1D from Part 1, amount 2G, or net income for tax purposes, whichever is the least) 1,679,294 2H

Note 1: For credit unions, this amount is before the deduction of bonus interest payments and payments pursuant to allocations in proportion to borrowing made by the credit union that is otherwise deductible under subsection 137(2).

Note 2: This amount must be prorated by the following calculation: eligible amount of the gift **divided** by the proceeds of disposition of the gift.

Part 3 – Gifts of certified cultural property

		Federal		Québec	Alberta
Gifts of certified cultural property at the end of the previous tax year			3A		
Gifts of certified cultural property expired after five tax years*	439				
Gifts of certified cultural property at the beginning of the current tax year (amount 3A **minus** line 439)	440				
Gifts of certified cultural property transferred on an amalgamation or the wind-up of a subsidiary	450				
Total gifts of certified cultural property in the current year (include this amount on line 112 of Schedule 1)	410				
Subtotal (line 450 **plus** line 410)			3B		
Subtotal (line 440 **plus** amount 3B)			3C		
Adjustment for an acquisition of control	455				
Amount applied in the current year against taxable income (enter this amount on line 313 of the T2 return)	460				
Subtotal (line 455 **plus** line 460)			3D		
Gifts of certified cultural property closing balance (amount 3C **minus** amount 3D)	480				

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Amount carried forward – Gifts of certified cultural property

Year of origin:		Federal	Québec	Alberta
1st prior year	2024-12-31			
2nd prior year	2023-12-31			
3rd prior year	2022-12-31			
4th prior year	2021-12-31			
5th prior year	2020-12-31			
6th prior year*	2019-12-31			
7th prior year	2018-12-31			
8th prior year	2017-12-31			
9th prior year	2016-12-31			
10th prior year	2015-12-31			
11th prior year	2015-11-04			
12th prior year	2015-10-31			
13th prior year	2014-12-31			
14th prior year	2013-12-31			
15th prior year	2012-12-31			
16th prior year	2011-12-31			
17th prior year	2010-12-31			
18th prior year	2009-12-31			
19th prior year	2008-12-31			
20th prior year	2007-12-31			
21st prior year*	2006-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 24, 2006, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 4 – Gifts of certified ecologically sensitive land

		Federal		Québec	Alberta
Gifts of certified ecologically sensitive land at the end of the previous tax year			4A		
Gifts of certified ecologically sensitive land expired after 5 tax years, or after 10 tax years for gifts made after February 10, 2014*	539				
Gifts of certified ecologically sensitive land at the beginning of the current tax year (amount 4A **minus** line 539)	540				
Gifts of certified ecologically sensitive land transferred on an amalgamation or the wind-up of a subsidiary	550				
Total current-year gifts of certified ecologically sensitive land (include this amount on line 112 of Schedule 1)	520				
Subtotal (line 550 **plus** line 520)			4B		
Subtotal (line 540 **plus** amount 4B)			4C		
Adjustment for an acquisition of control	555				
Amount applied in the current year against taxable income (enter this amount on line 314 of the T2 return)	560				
Subtotal (line 555 **plus** line 560)			4D		
Gifts of certified ecologically sensitive land closing balance (amount 4C **minus** amount 4D)	580				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, expire after five tax years and gifts made after February 10, 2014, expire after ten tax years. For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, expire after five tax years; otherwise, donation and gifts expire after twenty tax years.

Amounts carried forward – Gifts of certified ecologically sensitive land

Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date . . . . . .

Year of origin:		Federal	Québec	Alberta
1st prior year	2024-12-31			
2nd prior year	2023-12-31			
3rd prior year	2022-12-31			
4th prior year	2021-12-31			
5th prior year	2020-12-31			
6th prior year*	2019-12-31			
7th prior year	2018-12-31			
8th prior year	2017-12-31			
9th prior year	2016-12-31			
10th prior year	2015-12-31			
11th prior year*	2015-11-04			
12th prior year	2015-10-31			
13th prior year	2014-12-31			
14th prior year	2013-12-31			
15th prior year	2012-12-31			
16th prior year	2011-12-31			
17th prior year	2010-12-31			
18th prior year	2009-12-31			
19th prior year	2008-12-31			
20th prior year	2007-12-31			
21st prior year*	2006-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts made before February 11, 2014, that are included on line *6th prior year* and gifts that are included on line *11th prior year* expire automatically in the current year.

The field "Amount of carried forward gifts made on or after February 11, 2014, in the tax year including this date" is used to distinguish the portion of the gifts made in the tax year straddling February 11, 2014, that expires after ten tax years, from the portion that expires in the current tax year.

For Québec tax purposes, donations and gifts made during a tax year that ended before March 24, 2006, that are included on line *6th prior year* and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Part 5 – Additional deduction for gifts of medicine

		Federal		Québec	Alberta
Additional deduction for gifts of medicine at the end of the previous tax year			5A		
Additional deduction for gifts of medicine expired after five tax years*	639				
Additional deduction for gifts of medicine at the beginning of the current tax year (amount 5A **minus** line 639)	640				
Additional deduction for gifts of medicine made before March 22, 2017 transferred on an amalgamation or the wind-up of a subsidiary	650				
Additional deduction for gifts of medicine made before March 22, 2017:					
Proceeds of disposition	602				
Cost of gifts of medicine made before March 22, 2017	601				
Subtotal (line 602 **minus** line 601)			5B		
Amount 5B **multiplied** by 50 %			5C		
Eligible amount of gifts	600				

Federal

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . 610 _____

Québec

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . _____

Alberta

a _____ x (b _____ / c) = Additional deduction for gifts of medicine made before March 22, 2017 . . . . . _____

where:

a is the **lesser** of line 601 and amount 5C

b is the eligible amount of gifts (line 600)

c is the proceeds of disposition (line 602)

Subtotal (line 650 **plus** line 610)		5D		
Subtotal (line 640 **plus** amount 5D)		5E		
Adjustment for an acquisition of control	655			
Amount applied in the current year against taxable income (enter this amount on line 315 of the T2 return)	660			
Subtotal (line 655 **plus** line 660)		5F		
Additional deduction for gifts of medicine closing balance (amount 5E **minus** amount 5F) **(Note 3)**	680			

* For federal and Alberta tax purposes, donations and gifts expire after five tax years. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, expire after five tax years; otherwise, donations and gifts expire after twenty tax years.

Note 3: The amount at line 680 is not available for carryforward.

Amounts carried forward – Additional deduction for gifts of medicine

Year of origin:		Federal	Québec	Alberta
1st prior year	2024-12-31			
2nd prior year	2023-12-31			
3rd prior year	2022-12-31			
4th prior year	2021-12-31			
5th prior year	2020-12-31			
6th prior year*	2019-12-31			
7th prior year	2018-12-31			
8th prior year	2017-12-31			
9th prior year	2016-12-31			
10th prior year	2015-12-31			
11th prior year	2015-11-04			
12th prior year	2015-10-31			
13th prior year	2014-12-31			
14th prior year	2013-12-31			
15th prior year	2012-12-31			
16th prior year	2011-12-31			
17th prior year	2010-12-31			
18th prior year	2009-12-31			
19th prior year	2008-12-31			
20th prior year	2007-12-31			
21st prior year*	2006-12-31			
Total				

* For federal and Alberta tax purposes, donations and gifts included on line *6th prior year* expire automatically in the current tax year. For Québec tax purposes, donations and gifts made in a tax year that ended before March 19, 2007, that are included on line *6th prior year* and donations and gifts that are included on line *21st prior year* expire automatically in the current tax year.

Québec – Gifts of musical instruments

Gifts of musical instruments at the end of the previous tax year		A
Deduct: Gifts of musical instruments expired after twenty tax years		B
Gifts of musical instruments at the beginning of the tax year		C
Add:		
Gifts of musical instruments transferred on an amalgamation or the wind-up of a subsidiary		D
Total current-year gifts of musical instruments		E
Subtotal (line D **plus** line E)		F
Deduct: Adjustment for an acquisition of control		G
Total gifts of musical instruments available		H
Deduct: Amount applied against taxable income (enter this amount on line 255 of form CO-17)		I
Gifts of musical instruments closing balance		J

Amounts carried forward – Gifts of musical instruments

Year of origin:		Québec
1st prior year	2024-12-31	
2nd prior year	2023-12-31	
3rd prior year	2022-12-31	
4th prior year	2021-12-31	
5th prior year	2020-12-31	
6th prior year	2019-12-31	
7th prior year	2018-12-31	
8th prior year	2017-12-31	
9th prior year	2016-12-31	
10th prior year	2015-12-31	
11th prior year	2015-11-04	
12th prior year	2015-10-31	
13th prior year	2014-12-31	
14th prior year	2013-12-31	
15th prior year	2012-12-31	
16th prior year	2011-12-31	
17th prior year	2010-12-31	
18th prior year	2009-12-31	
19th prior year	2008-12-31	
20th prior year	2007-12-31	
21st prior year*	2006-12-31	
Total		

* These gifts expired in the current year.

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Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1), (b), (c) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A.1 – Enter "X" if dividends were received from a foreign source.
  Column G.1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, G, G.1, J, J.1, J.2 and M **only if** the payer corporation is **connected**.

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns K, L and M use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A.1	B Enter 1 if payer corporation is **connected** 205	C Business number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends reported under column 240 were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from income under paragraph 113(1)(c) **235**	G Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1) (a), (a.1), (b), or (d) [1] **240**	G.1	H Eligible dividends included under column 240 **242**	I Total taxable dividends paid by the **connected** payer corporation (for tax year in column D) **250**	I.1 Total eligible dividends paid by the **connected** payer corporation (line 465 in Schedule 3 for the tax year in column D)
1						

	J Dividend refund of the **connected** payer corporation (for tax year in column D) [2] **260**	J.1 Eligible dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (amount CC from T2 return for the tax year in column D)	J.2 Additional non-eligible dividend refund of the **connected** payer corporation from its ERDTOH (amount II from T2 return for the tax year in column D)	K Part IV tax for eligible dividends. Dividends (from column H) **multiplied** by 38 1/3% [3] **265**	L Part IV tax before deductions. Dividends (from column G) **multiplied** by 38 1/3% [4] **275**	M Part IV tax before deductions on taxable dividends received from **connected** corporations [5] **280**
1						

Total of column M (enter amount on line 2E in Part 2) _____

Total taxable dividends deductible reported under column 235 . . . . . _____ 1A

Total taxable dividends deductible reported under column 240 . . . . . _____ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) _____ 1C

Eligible dividends received from connected corporations (total amounts from column H with code 1 in column B) . . . . . _____ 1D

Eligible dividends received from non-connected corporations (total amounts from column H with no code in column B) . . . . . _____ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column L with code 1 in column B) . . . . . _____ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column L with no code in column B) . . . . . _____ 1G

Subtotal (amount 1F **plus** amount 1G) _____ ▶ _____ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column K with code 1 in column B) . . . . . _____ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column K with no code in column B) . . . . . _____ 1J

Subtotal (amount 1I **plus** amount 1J) _____ ▶ _____ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) . . . . . _____ 1L

1 If taxable dividends are received, enter the amount in column G, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column L (and column K, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the **connected** payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable.

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to column J **divided** by column I **multiplied** by column H.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to column J **divided** by column I **multiplied** by column G.

5 For the purpose of calculating your eligible refundable dividend tax on hand (ERDTOH), Part IV tax on taxable dividends received from **connected** corporations (with a tax year starting after 2018) is equal to the sum of Part IV tax on eligible dividends and non-eligible dividends received from **connected** corporations to the extent that such dividends caused a dividend refund to those corporations from their ERDTOH.

Part IV tax before deductions on taxable dividends received from **connected** corporations for purposes of column M is the lesser of the Part IV tax applicable to such taxable dividends and the sum of (i) and (ii), where

(i) Part IV tax on eligible dividends received from **connected** corporations is equal to amount CC of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 465 of the **connected** payer corporation, **multiplied** by column H; and

(ii) Part IV tax on non-eligible dividends received from **connected** corporations is equal to amount II of the **connected** payer corporation (on page 7 of the T2 return) **divided** by line 470 of the **connected** payer corporation, **multiplied** by the difference between columns G and H.

Part 2 – Calculation of Part IV tax payable

Is your corporation an exempt corporation for the purposes of Part IV tax as per subsection 186.1(b)(ii) or (vii) of the Act? **100** [X] Yes [ ] No

If **yes**, proceed to Part 3.

If **no**, complete the rest of Part 2.

Part IV tax on dividends received before deductions (amount 1H in part 1) 2A

Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43) **320**

Subtotal (amount 2A **minus** line 320) ▶ 2B

Current-year non-capital loss claimed to reduce Part IV tax **330**

Non-capital losses from previous years claimed to reduce Part IV tax **335**

Current-year farm loss claimed to reduce Part IV tax **340**

Farm losses from previous years claimed to reduce Part IV tax **345**

Total losses applied against Part IV tax (total of lines 330 to 345) 2C

Amount 2C **multiplied** by 38 1 / 3 % 2D

Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") **360**

(enter amount on line 712 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column M in part 1) 2E

Amount 4A from Schedule 43 . . . . . 2F

Part IV tax payable on taxable dividends received from connected corporations
(amount 2E **minus** amount 2F, if negative enter "0") 2G

(enter at amount C on page 7 of the T2 return)

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1) 2H

Amount 4C from Schedule 43 . . . . . 2I

Part IV tax payable on taxable dividends received from non-connected corporations
(amount 2H **minus** amount 2I, if negative enter "0") 2J

(enter at amount D on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	N Name of recipient corporation with which you are connected **400**	O Business number **410**	P Tax year-end of recipient corporation in which the dividends reported under column 430 were received YYYYMMDD **420**	Q Taxable dividends paid to recipient corporations with which you are connected **430**	R Eligible dividends included under column 430 **440**
1	Hydro One Inc.		2025-12-31	791,700,485	791,700,485
				791,700,485 (Total of column Q)	791,700,485 (Total of column R)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations		450	
Eligible dividends included in line 450	455		
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column Q **plus** line 450)		460	791,700,485
Total eligible dividends paid in the tax year (total of column R **plus** line 455)		465	791,700,485
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)		470	

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)	303,485,186	3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)		3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)			791,700,485
Other dividends paid in the tax year (total of 510 to 540)			
Total dividends paid in the tax year		500	791,700,485
Dividends paid out of capital dividend account	510		
Capital gains dividends	520		
Dividends paid on shares described in subsection 129(1.2)	530		
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540		
Subtotal (total of lines 510 to 540)		▶	4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (line 500 **minus** amount 4A)			791,700,485 4B

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Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, limited partnership loss, or restricted interest and financing expense; to determine the amount of restricted farm losses, limited partnership losses, and restricted interest and financing expenses (RIFE) that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- All legislative references are to the federal Income Tax Act.
- According to subsection 111(4), when control has been acquired, no amount of capital loss incurred in a tax year ending before that time is deductible when calculating taxable income for a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible when calculating taxable income for a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses except as listed in paragraphs 111(5)(a) and (b), and of RIFE except as listed in paragraph 111(5)(a).
- For information on these losses, see Guide T4012, T2 Corporation – Income Tax.
- File this schedule with the T2 Corporation Income Tax Return, or send the schedule by itself to the tax centre where the return is filed.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes		613,168,945	1A
RIFE deducted in the year under paragraph 111(1)(a.1) (enter as a positive amount)			1B
Net capital losses deducted in the year (enter as a positive amount)			1C
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)			1D
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)			1E
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)			1F
Employer deduction for non-qualified securities – Paragraph 110(1)(e)			1G
Subtotal (total of amounts 1B to 1G)			1H
Subtotal (amount 1A **minus** amount 1H; if positive, enter "0")			1I
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions			1J
Subtotal (amount 1I **minus** amount 1J)			1K
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)			1L
Current-year non-capital loss (amount 1K **plus** amount 1L, if positive enter "0") If amount 1M is negative, enter it on line 110 as a positive amount.			1M

Continuity of non-capital losses and request for a carryback

Non-capital losses at the end of the previous tax year		85,812,219	1N	
Non-capital loss expired [1]	100			
Non-capital losses at the beginning of the tax year (amount 1N **minus** line 100)	102	85,812,219		85,812,219
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary [2] corporation	105			
Current-year non-capital loss (from amount 1M)	110			
Subtotal (line 105 **plus** line 110)				1O
Subtotal (line 102 **plus** amount 1O)				85,812,219 1P

[1] A non-capital loss expires after **20 tax years** and an allowable business investment loss becomes a net capital loss after **10 tax years**.

[2] Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	150			
Section 80 – Adjustments for forgiven amounts	140			
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter the amount from line 130 on line 331 of the T2 return.	130	85,812,219		
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax [3]	135			
Subtotal (total of lines 150, 140, 130 and 135)		85,812,219	▶ 85,812,219	1Q
Non-capital losses before any request for a carryback (amount 1P **minus** amount 1Q)				1R

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901			
Second previous tax year to reduce taxable income	902			
Third previous tax year to reduce taxable income	903			
First previous tax year to reduce taxable dividends subject to Part IV tax	911			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)			▶	1S
Closing balance of non-capital losses to be carried forward to future tax years (amount 1R **minus** amount 1S)	180			

[3] Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205			
Subtotal (line 200 **plus** line 205)			▶	2A
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Subtotal (line 250 **plus** line 240)			▶	2B
Subtotal (amount 2A **minus** amount 2B)				2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)	210			
Unused non-capital losses from the 11th previous tax year [4]				2D
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year [5]				2E
Enter amount 2D or 2E, whichever is less	215			
ABILs expired as non-capital losses (line 215 **multiplied** by 2.000000)	220			
Subtotal (amount 2C **plus** line 210 **plus** line 220)				2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

[4] Determine the amount of the non-capital loss from the **11th previous tax year**, and enter the part of the non-capital loss that was not deducted in the **previous 11 years**.

[5] Enter the amount of the ABILs from the **11th previous tax year**. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain [6] . . . . . **225** _____

Capital losses before any request for a carryback (amount 2F **minus** line 225) _____ 2G

Request to carry back capital loss to: [7]

	Capital gain (100%)		Amount carried back (100%)
First previous tax year	973,153	**951**	
Second previous tax year	2,773,951	**952**	
Third previous tax year	37,301,183	**953**	
Subtotal (total of lines 951 to 953)			▶ _____ 2H

Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) [8] **280** _____

[6] To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

[7] On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

[8] Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year . . . . . _____ 3A

Farm loss expired [9] . . . . . **300** _____

Farm losses at the beginning of the tax year (amount 3A **minus** line 300) . . . . . **302** _____ ▶ _____

Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation **305** _____

Current-year farm loss (amount 1L in Part 1) . . . . . **310** _____

Subtotal (line 305 **plus** line 310) _____ ▶ _____ 3B

Subtotal (line 302 **plus** amount 3B) _____ 3C

Other adjustments (includes adjustments for an acquisition of control) . . . . . **350** _____

Section 80 – Adjustments for forgiven amounts . . . . . **340** _____

Farm losses of previous tax years applied in the current tax year . . . . . **330** _____
Enter the amount from line 330 on line 334 of the T2 Return.

Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax [10] . . . . . **335** _____

Subtotal (total of lines 350, 340, 330 and 335) _____ ▶ _____ 3D

Farm losses before any request for a carryback (amount 3C **minus** amount 3D) _____ 3E

Request to carry back farm loss to:

First previous tax year to reduce taxable income . . . . . **921** _____

Second previous tax year to reduce taxable income . . . . . **922** _____

Third previous tax year to reduce taxable income . . . . . **923** _____

First previous tax year to reduce taxable dividends subject to Part IV tax . . . . . **931** _____

Second previous tax year to reduce taxable dividends subject to Part IV tax . . . . . **932** _____

Third previous tax year to reduce taxable dividends subject to Part IV tax . . . . . **933** _____

Subtotal (total of lines 921 to 933) _____ ▶ _____ 3F

Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F) **380** _____

[9] A farm loss expires after **20 tax years**.

[10] Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business . . . . . **485** _____

(line 485 _____ – $2,500) **divided** by 2 . . . . . _____ 4A

Amount 4A or $ 15,000 , whichever is less . . . . . _____ ▶ _____ 4B

2,500 4C

Subtotal (amount 4B **plus** amount 4C) 2,500 ▶ 2,500 4D

Current-year restricted farm loss (line 485 **minus** amount 4D) _____ 4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year . . . . . _____ 4F

Restricted farm loss expired [11] . . . . . **400** _____

Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400) . . . . . **402** _____ ▶ _____

Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation . . . . . **405** _____

Current-year restricted farm loss (from amount 4E) . . . . . **410** _____

Enter the amount from line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.

Subtotal (line 405 **plus** line 410) _____ ▶ _____ 4G

Subtotal (line 402 **plus** amount 4G) _____ 4H

Restricted farm losses from previous tax years applied against current farming income . . . . . **430** _____

Enter the amount from line 430 on line 333 of the T2 return.

Section 80 – Adjustments for forgiven amounts . . . . . **440** _____

Other adjustments . . . . . **450** _____

Subtotal (total of lines 430 to 450) _____ ▶ _____ 4I

Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I) _____ 4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income . . . . . **941** _____

Second previous tax year to reduce farming income . . . . . **942** _____

Third previous tax year to reduce farming income . . . . . **943** _____

Subtotal (total of lines 941 to 943) _____ ▶ _____ 4K

Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K) **480** _____

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

[11] A restricted farm loss expires after **20 tax years**.

Part 5 – Listed personal property losses

Continuity of listed personal property losses and request for a carryback

Listed personal property losses at the end of the previous tax year			5A	
Listed personal property loss expired[12]	500			
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502		▶	
Current-year listed personal property loss (from Schedule 6)			510	
Subtotal (line 502 **plus** line 510)				5B
Listed personal property losses from previous tax years applied against listed personal property gains Enter the amount from line 530 on line 655 of Schedule 6.	530			
Other adjustments	550			
Subtotal (line 530 **plus** line 550)			▶	5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)				5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961			
Second previous tax year to reduce listed personal property gains	962			
Third previous tax year to reduce listed personal property gains	963			
Subtotal (total of lines 961 to 963)			▶	5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)	580			

[12] A listed personal property loss expires after **seven tax years**.

Part 7 – Limited partnership losses

Current-year limited partnership losses

	1	2	3	4	5	6	7
	Partnership account number 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, clean economy tax credit, farming losses, and resource expenses[15] 608	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) 620
1.							

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

	1	2	3	4	5	6	7
	Partnership account number 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, clean economy tax credit, business or property losses, and resource expenses[15] 638	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650
1.							

Continuity of limited partnership losses that can be carried forward to future tax years

	1	2	3	4	5	6
	Partnership account number 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary 664	Current-year limited partnership losses (from line 620) 670	Limited partnership losses applied in the current year (must be equal to or less than line 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) 680
1.						

Total (enter this amount on line 335 of the T2 return)

If you need more space, you can attach more schedules.

[15] Clean economy tax credit is defined in subsection 127.47(1).

Part 8 – Restricted interest and financing expenses (RIFE)

Continuity of RIFE

RIFE at the end of the previous tax year . . . . . **700** _____

RIFE transferred on an amalgamation or on the wind-up of a subsidiary corporation . . . . . **705** _____

RIFE adjustments for an acquisition of control . . . . . **750** _____

Subtotal (line 700 **plus** line 705 **minus** line 750) _____ ▶ _____ 8A

Enter amount 8A on line 128 in Part 2J of Schedule 130, Excessive Interest and Financing Expenses Limitation.

Current-year restricted interest and financing expense determined under subsection 111(8) (amount A from Part 2O of Schedule 130) . . . . . **710** _____

RIFE deducted for the tax year [16] . . . . . **730** _____

Enter the amount from line 730 on line 336 of the T2 return.

Closing balance of RIFE (amount 8A **plus** line 710 **minus** line 730) **780** _____

[16] The amount deducted **must** not exceed amount B in Part 2J of Schedule 130.

Part 9 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), tick the box . . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind-up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note
This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

See the privacy notice on your return.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce		Balance at end of year
					Taxable income	Part IV tax	
Current	N/A				N/A		
1st preceding taxation year 2024-12-31		N/A		N/A			
2nd preceding taxation year 2023-12-31		N/A		N/A			
3rd preceding taxation year 2022-12-31	25,029,952	N/A		N/A	25,029,952		
4th preceding taxation year 2021-12-31	1,113,963	N/A		N/A	1,113,963		
5th preceding taxation year 2020-12-31	2,990,720	N/A		N/A	2,990,720		
6th preceding taxation year 2019-12-31	56,677,584	N/A		N/A	56,677,584		
7th preceding taxation year 2018-12-31		N/A		N/A			
8th preceding taxation year 2017-12-31		N/A		N/A			
9th preceding taxation year 2016-12-31		N/A		N/A			
10th preceding taxation year 2015-12-31		N/A		N/A			
11th preceding taxation year 2015-11-04		N/A		N/A			
12th preceding taxation year 2015-10-31		N/A		N/A			
13th preceding taxation year 2014-12-31		N/A		N/A			
14th preceding taxation year 2013-12-31		N/A		N/A			
15th preceding taxation year 2012-12-31		N/A		N/A			
16th preceding taxation year 2011-12-31		N/A		N/A			
17th preceding taxation year 2010-12-31		N/A		N/A			
18th preceding taxation year 2009-12-31		N/A		N/A			
19th preceding taxation year 2008-12-31		N/A		N/A			
20th preceding taxation year 2007-12-31		N/A		N/A			*
Total	85,812,219				85,812,219		

* **This balance expires this year and will not be available next year.**

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Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Use this schedule if any of the following apply to your corporation during the tax year:

- it had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only fill out columns A, B, and D in Part 1)
- it is claiming provincial or territorial tax credits or rebates (see Part 2)
- it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)

All legislative references are to the Income Tax Regulations.

For more information, see Guide T4012, T2 Corporation – Income Tax Guide.

For the regulation number to be entered in field 100 of Part 1, see the chart in the Help (F1).

Part 1 – Allocation of taxable income

100 _____ Enter the regulation that applies (402 to 413).

A Jurisdiction. (tick **yes** if your corporation had a permanent establishment in the jurisdiction during the tax year) **Note 1**		B Total salaries and wages paid in jurisdiction	C B **multiplied** by taxable income, **divided** by G	D Gross revenue attributable to jurisdiction	E D **multiplied** by taxable income, **divided** by H	F Allocation of taxable income (C + E x 1/2) **Note 2** (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes ☐	113		153		
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes ☐	119		159		
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G		169 H		

Note 1: **Permanent establishment** is defined in subsection 400(2).
Note 2: For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:

1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, fill out Part 2 on the following pages.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

T2 SCH 5 E (26)

Canada

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits
525,677,432		525,677,432	60,452,905

Ontario basic income tax (from Schedule 500)	270	60,452,905		
Ontario small business deduction (from Schedule 500)	402			
Subtotal (line 270 **minus** line 402)		60,452,905	▶ 60,452,905	5A
Ontario transitional tax debits and credits (from Schedule 506)	276			
Recapture of Ontario research and development tax credit (from Schedule 508)	277			
Repayment of Ontario made manufacturing investment tax credit (from Schedule 572)	281			
Subtotal (line 276 **plus** line 277 **plus** line 281)			▶	5B
Gross Ontario tax (amount 5A **plus** amount 5B)			60,452,905	5C
Ontario tax credit for manufacturing and processing (from Schedule 502)	406			
Ontario foreign tax credit (from Schedule 21)	408			
Ontario credit union tax reduction (from Schedule 500)	410			
Ontario political contributions tax credit (from Schedule 525)	415			
Ontario non-refundable tax credits (total of lines 406 to 415)			▶	5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")			60,452,905	5E
Ontario research and development tax credit (from Schedule 508)	416			
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")			60,452,905	5F
Ontario corporate minimum tax credit (from Schedule 510)	418		21,268,055	
Ontario community food program donation tax credit for farmers (from Schedule 2)	420			
Non-refundable Ontario made manufacturing investment tax credit (from Schedule 572)	421			
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 to 421) (if negative, enter "0")			39,184,850	5G
Ontario corporate minimum tax (from Schedule 510)	278			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280			
Subtotal (line 278 **plus** line 280)			▶	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)			39,184,850	5I
Ontario qualifying environmental trust tax credit	450			
Ontario co-operative education tax credit (from Schedule 550)	452	933,000		
Ontario computer animation and special effects tax credit (from Schedule 554)	456			
Ontario film and television tax credit (from Schedule 556)	458			
Ontario production services tax credit (from Schedule 558)	460			
Ontario interactive digital media tax credit (from Schedule 560)	462			
Ontario book publishing tax credit (from Schedule 564)	466			
Ontario innovation tax credit (from Schedule 566)	468			
Ontario business-research institute tax credit (from Schedule 568)	470			
Ontario regional opportunities investment tax credit (from Schedule 570)	472			
Refundable Ontario made manufacturing investment tax credit (from Schedule 572)	474			
Ontario shortline railway investment tax credit	476			
Ontario refundable tax credits (total of lines 450 to 476)		933,000	▶ 933,000	5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets). Include this amount on line 255.	290		38,251,850	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits **255** 38,251,850

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

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Schedule 6

Summary of Dispositions of Capital Property

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Use this schedule if your corporation disposed of (actual or deemed) capital property or claimed an allowable business investment loss (ABIL), or both, in the tax year.
- All legislative references are to the Income Tax Act.
- Also use this schedule to make a designation under paragraph 111(4)(e) if control of the corporation has been acquired by a person or a group of persons.
- For more information, see the section called "Schedule 6, Summary of Dispositions of Capital Property" in the T2 Corporation Income Tax Guide.
- If you need more space, attach additional schedules.

Designation under paragraph 111(4)(e)

Are any dispositions shown on this schedule related to deemed dispositions designated under paragraph 111(4)(e)? . . . . 050 Yes ☐ No ☒

If **yes**, attach a statement specifying which properties such a designation applies to.

In the various sections of this form:

- The abbreviation **FS** (for foreign source) is used to indicate the capital gain or loss arising from foreign property;
- The abbreviation **PA** (for passive asset) is used to indicate the capital gain or loss arising from the disposition of an asset other than an active asset of the corporation.

Part 1 – Shares

1 Number of shares 100	2 Name of corporation in which the shares were held 105	3 Class of shares 106	4 Date of acquisition YYYYMMDD 110	5 Proceeds of disposition 120	6 Adjusted cost base 130	7 Outlays and expenses from disposition 140	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 150	A FS	A PA
8115163	Chatham X Lakeshore Lir	Units	2024-12-17	8,070,813	7,039,323		1,031,490		
8115163	Chatham X Lakeshore Lir	Units	2024-12-17	8,062,689	6,671,652		1,391,037		
			Totals	16,133,502	13,710,975		2,422,527		

Total adjustment under subsection 112(3) to all losses identified in column 8 . . . . . 160 _____

Actual gain or loss from the disposition of shares (total of column 8 **plus** line 160) . . . . . 2,422,527 **A**

Part 2 – Real estate (Do not include losses on depreciable property)

1 Municipal address of real estate 1 = Address 1 2 = Address 2 3 = City 4 = Province, Country, Postal Code and Zip Code or Foreign Postal Code 200	2 Date of acquisition YYYYMMDD 210	3 Proceeds of disposition 220	4 Adjusted cost base 230	5 Outlays and expenses from disposition 240	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 250	A FS	A PA
Pt Canadian National Railway	1945-06-30	250,000	100		249,900		
Sheet 29 PL 335 East Whitby							
Oshawa							
ON CA L1H 3M3							
	Totals	250,000	100		249,900	**B**	

Part 3 – Bonds

1 Face value of bonds 300	2 Maturity date YYYYMMDD 305	3 Name of bond issuer 307	4 Date of acquisition YYYYMMDD 310	5 Proceeds of disposition 320	6 Adjusted cost base 330	7 Outlays and expenses from disposition 340	8 Gain (or loss) (column 5 **minus** columns 6 and 7) 350	A FS	A PA
			Totals					**C**	

Part 4 – Other properties (Do not include losses on depreciable property)

1 Description of other property 400	2 Date of acquisition YYYYMMDD 410	3 Proceeds of disposition 420	4 Adjusted cost base 430	5 Outlays and expenses from disposition 440	6 Gain (or loss) (column 3 **minus** columns 4 and 5) 450	A FS PA
	Totals					D

Other property includes capital debts, debts in respect of the disposition of a personal-use property per subsection 50(2), amounts that arise from foreign currency transactions, and capital gains (losses) allocated from partnerships and trusts.

If you are a member of a partnership, include:

- under column 3 (line 420), any capital gain reported in boxes 151, 270, or 271 of the T5013 slips
- under column 4 (line 430), any capital loss reported in boxes 151, 270, or 271 of the T5013 slips

If you are a beneficiary of a trust, include under column 3 (line 420) the amount reported in box 21 of the T3 slips.

Part 5 – Personal-use property (Do not include listed personal property)

1 Description of personal-use property 500	2 Date of acquisition YYYYMMDD 510	3 Proceeds of disposition 520	4 Adjusted cost base 530	5 Outlays and expenses from disposition 540	6 Gain only (column 3 **minus** columns 4 and 5; if negative, enter "0") 550	A FS PA
	Totals					E

You **cannot** deduct losses on dispositions of personal-use property (other than listed personal property or a debt that is a personal-use property) from your income.

Part 6 – Listed personal property

1 Description of listed personal property 600	2 Date of acquisition YYYYMMDD 610	3 Proceeds of disposition 620	4 Adjusted cost base 630	5 Outlays and expenses from disposition 640	6 Gain (or loss) (column 3 **minus** columns 4 and 5) Note 1 650	A FS PA
	Totals					

Unapplied listed personal property losses from other years (amount from line 530 of Schedule 4, Corporation Loss Continuity and Application) . . . . . 655 _____

Net gains (or losses) from the disposition of listed personal property (total of column 6 **minus** line 655) . . . . . _____ F

Net listed personal property losses can only be applied against listed personal property gains.

Note 1: Do **not** include gains arising on the disposition of certain certified cultural property to a designated cultural institution. See subparagraph 39(1)(a)(i.1) for more information.

Part 7 – Property qualifying for and resulting in an allowable business investment loss

1 Name of small business corporation 900	2 Shares, enter **1**; debt, enter **2** 905	3 Date of acquisition YYYYMMDD 910	4 Proceeds of disposition 920	5 Adjusted cost base 930	6 Outlays and expenses from disposition 940	7 Loss only (column 4 **minus** columns 5 and 6) 950	A FS PA
		Totals					

Allowable business investment losses (ABILs) . . . . . Total of Column 7 _____ x 1/2 = _____ G

Enter amount G on line 406 of Schedule 1, Net Income (Loss) for Income Tax Purposes.

Properties listed in Part 7 should **not** be included in any other parts of this schedule.

Part 8 – Capital gains or losses

Total of amounts A to F (do **not** include amount F if it is a loss)		2,672,427	H	
				FS PA
Capital gains dividend received in the year	875			☐ ☐
Capital gains reserve opening balance (from Part 1 of Schedule 13, Continuity of Reserves)	880			
Subtotal (amount H **plus** total of lines 875 and 880)		2,672,427	I	
Capital gains reserve closing balance (from Part 1 of Schedule 13, Continuity of Reserves)	885			
Capital gains or losses, excluding ABILs (amount I **minus** line 885)	890	2,672,427		

Part 9 – Taxable capital gains and total capital losses

Capital gains or losses, excluding ABILs (amount from line 890 in Part 8) . . . . . 2,672,427 J

Deduct the following amounts included in amount J, that are subject to the zero inclusion rate[Note 2]:

				FS PA
Gain on the donation to a qualified donee of a share, debt obligation, or right listed on a designated stock exchange and other securities under paragraphs 38(a.1)(i) and (iii)	895			☐ ☐
				FS PA
Gain on the donation to a qualified donee of ecologically sensitive land under subsection 38(a.2)[Note 3]	896			☐ ☐
				FS PA
Exempt portion of the gain on the donation of securities arising from the exchange of a partnership interest under subsection 38(a.3)			a	☐ ☐
Subtotal (line 895 **plus** line 896 **plus** line a)		▶		K
Subtotal (amount J **minus** amount K)		2,672,427	L	

Deemed capital gain from the donation of property included in a flow-through share class of property to a qualified donee under subsection 40(12):

Exemption threshold at time of disposition	897	
The total of all capital gains from the actual disposition of the property	898	
		FS PA
Line 897 or line 898, whichever is less		M ☐ ☐

Taxable capital gains under section 34.2 (line 275 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)		x	2 =	899	
Subtotal (total of amounts L and M **plus** line 899)					2,672,427 N
Allowable capital losses under section 34.2 (line 285 of Schedule 73, Income Inclusion Summary for Corporations that are Members of Partnerships)		x	2 =	901	
Subtotal (amount N **minus** line 901)					2,672,427 O
					FS PA
Portion of the capital gain that is subject to a 100% inclusion rate per 100(1)[Note 4]	1,211,263	x	2 =	902	2,422,526 ☐ ☐
Total capital gains or losses (amount O **plus** line 902)					5,094,953 P

Taxable capital gains or total capital losses

Total capital losses (if amount P is negative, enter amount P; if amount P is positive, enter "0") . . . . . Q

Enter amount Q on line 210 of Schedule 4.

Taxable capital gains (if amount P is positive, enter the result of amount P 5,094,953 multiplied by 50.0000 %; if amount P is negative, enter "0") . . . . . 2,547,477 R

Enter amount R on line 113 of Schedule 1.

Note 2: When a taxpayer is entitled to an advantage in respect of a donation, the zero inclusion rate is restricted to only that part of the taxpayer's capital gain on disposition of the property that is attributable to the eligible amount of the donation. The amount of the gain attributable to any advantage (or benefit) received in respect of the donation is subject to the ordinary capital gains inclusion rate. See section 38.2 for more information.

Note 3: Do **not** include gains on donations of ecologically sensitive land to a private foundation.

Note 4: Do **not** include any portion of the capital gain that is subject to the 50% inclusion rate. Enter any such portion in Part 4. If you are a member of a partnership, include the amount reported in box 289 of the T5013 slip.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the corporation is claiming for the tax year or to account for acquisitions or dispositions of depreciable property, or both.
- Unless otherwise stated, all legislative references are to the Income Tax Act.
- For more information, see the section called "Schedule 8, Capital Cost Allowance (CCA)" in Guide T4012, T2 Corporation – Income Tax.
- If you do not have enough space to list all the information, use an additional Schedule 8.
- Attach the original copy of this completed schedule to your T2 Corporation Income Tax Return.

Is the corporation electing under subsection 1101(5q) of the Income Tax Regulations? **101** Yes ☐ No ☒

	1 Class number Note 1 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) Note 2 203	4 Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP) or property acquired before 2025 that is included in Classes 54 to 56 Note 3 225	5 Cost of acquisitions from column 3 that are reaccelerated investment incentive property (RIIP) or property acquired after 2024 that is included in Classes 54 to 56 Note 4 226	6 Adjustments and transfers Note 5 205	7 Amount from column 6 that is assistance received or receivable during the year for a property, subsequent to its disposition Note 6 221	8 Amount from column 6 that is repaid during the year for a property, subsequent to its disposition Note 7 222
1.	1		4,255,329,226	199,432,379	89,004,538	110,427,841			
2.	1b		25,190						
3.	2		1,847,420,753						
4.	3		205,334,123	27,722	17,307	10,415			
5.	6		72,008,779	5,406,242	2,185,415	3,220,827			
6.	7		1,690,990						
7.	8		202,188,093	46,051,572	26,563,686	19,487,886			
8.	9		14,040,168	7,244,592	2,701,300	4,543,292			
9.	10	Class 10.1	12,765,715	8,333,251		8,333,251			
10.	10		65,889,755	37,423,713	13,667,461	23,756,252			
11.	12			127,902,347	46,999,426	80,902,921			
12.	13	2300 Yonge St (WBS 700052298)	116,147						
13.	13	420 Welham Rd Barrie (WBS 700060775)	10,694						
14.	13	483 Bay Street (WBS 300040950)	146,391						
15.	13	483 Bay Street (WBS 300042991C/7000015844/843	2,527,844						
16.	13	483 Bay Street ELT 8th Floor (WBS 700063162)	711,124						
17.	13	Alliston OC (WBS 700050153)	15,110						

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	1 Class number Note 1 200	Description	2 Undepreciated capital cost (UCC) at the beginning of the year 201	3 Cost of acquisitions during the year (new property must be available for use) Note 2 203	4 Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP) or property acquired before 2025 that is included in Classes 54 to 56 Note 3 225	5 Cost of acquisitions from column 3 that are reaccelerated investment incentive property (RIIP) or property acquired after 2024 that is included in Classes 54 to 56 Note 4 226	6 Adjustments and transfers Note 5 205	7 Amount from column 6 that is assistance received or receivable during the year for a property, subsequent to its disposition Note 6 221	8 Amount from column 6 that is repaid during the year for a property, subsequent to its disposition Note 7 222
18.	13	Barrie Corporate Office (WBS 700050155)	10,811						
19.	13	BASC office reno (WBS 700057942)	93,959						
20.	13	Bracebridge Forestry (WBS 700050490)	7,887						
21.	13	Newmarket SC (WBS 700016578/700052236)	36,758						
22.	13	PCB Light Replacement	794						
23.	13	Smart Meter Facility - 255 Matheson Blvd Miss	1,676,494	1,108,440	282,347	826,093			
24.	13	Sudbury (WBS 700010356)	14,123						
25.	13	Sudbury 500 Barrydowne (WBS 700025393)	2,273						
26.	13	Switch to LED fixtures/light bulbs	68,487						
27.	13	Thunder Bay Fleet Garage (WBS 7000032535)	2,180,037						
28.	13	Timmins OC 569-571 Moneta Dr (WBS 700052236)	8,296						
29.	13	Timmins Fleet Garage Auto Gate (WBS 700057953	297,706						
30.	13	Woodstock office 763 Athlone Dr WBS 700042562	3,440,361						
31.	14	Post-2016	1,449,017						
32.	14.1	Pre-2017 (formerly ECE)	2,022,836,267						
33.	14.1		55,206,926				1,397,833		
34.	17		314,058,483	36,411,397	19,940,645	16,470,752			
35.	42		47,598,253				-624		
36.	43.1		301,727				-86,706		
37.	43.2		61						
38.	45		151,817						
39.	46		11,550,484	665,412	578,931	86,481			
40.	47		11,092,930,045	2,091,329,368	915,396,947	1,175,932,421	-1,412,011		
41.	50		17,685,782	26,488,314	10,611,250	15,877,064			
42.	54		1,113,250	2,756,818		2,756,818			
		Totals	20,252,940,200	2,590,581,567	1,127,949,253	1,462,632,314	-101,508		

	1 Class number	Description	9 Proceeds of dispositions Note 8 207	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 6 **minus** column 9) Note 9	11 Proceeds of dispositions available to reduce additions of AIIP, RIIP and property included in Classes 54 to 56 (column 7 **plus** column 9 **minus** column 3 **plus** column 4 **plus** column 5 **minus** column 8) (if negative, enter "0")	12 Net capital cost additions of AIIP and property acquired before 2025 that is included in Classes 54 to 56 (column 4 **minus** column 11) (if negative, enter "0")	13 Proceeds of dispositions from column 11 available to reduce additions of RIIP and ZEV acquired after 2024 that is included in Classes 54 to 56 (column 11 **minus** column 4) (if negative, enter "0")	14 Net capital cost additions of RIIP and property acquired after 2024 that is included in Classes 54 to 56 (column 5 **minus** column 13) (if negative, enter "0")	15 UCC adjustment for AIIP and property acquired before 2025 that is included in Classes 54 to 56 (column 12 **multiplied** by the relevant factor) Note 10
1.	1		122,357	4,454,639,248	122,357	88,882,181		110,427,841	
2.	1b		0	25,190					
3.	2		0	1,847,420,753					
4.	3		0	205,361,845		17,307		10,415	
5.	6		547,862	76,867,159	547,862	1,637,553		3,220,827	
6.	7		0	1,690,990					
7.	8		931,911	247,307,754	931,911	25,631,775		19,487,886	
8.	9		2,110,060	19,174,700	2,110,060	591,240		4,543,292	
9.	10	Class 10.1	0	21,098,966				8,333,251	
10.	10		3,045,504	100,267,964	3,045,504	10,621,957		23,756,252	
11.	12		131,341	127,771,006	131,341	46,868,085		80,902,921	
12.	13	2300 Yonge St (WBS 700052298)	0	116,147					
13.	13	420 Welham Rd Barrie (WBS 700060775)	0	10,694					
14.	13	483 Bay Street (WBS 300040950)	0	146,391					
15.	13	483 Bay Street (WBS 300042991C/7000015844/843	0	2,527,844					
16.	13	483 Bay Street ELT 8th Floor (WBS 700063162)	0	711,124					
17.	13	Alliston OC (WBS 700050153)	0	15,110					
18.	13	Barrie Corporate Office (WBS 700050155)	0	10,811					
19.	13	BASC office reno (WBS 700057942)	0	93,959					
20.	13	Bracebridge Forestry (WBS 700050490)	0	7,887					
21.	13	Newmarket SC (WBS 700016578/700052236)	0	36,758					
22.	13	PCB Light Replacement	0	794					
23.	13	Smart Meter Facility - 255 Matheson Blvd Miss	0	2,784,934		282,347		826,093	
24.	13	Sudbury (WBS 700010356)	0	14,123					
25.	13	Sudbury 500 Barrydowne (WBS 700025393)	0	2,273					
26.	13	Switch to LED fixtures/light bulbs	0	68,487					
27.	13	Thunder Bay Fleet Garage (WBS 7000032535)	0	2,180,037					
28.	13	Timmins OC 569-571 Moneta Dr (WBS 700052236)	0	8,296					
29.	13	Timmins Fleet Garage Auto Gate (WBS 700057953	0	297,706					
30.	13	Woodstock office 763 Athlone Dr WBS 700042562	0	3,440,361					
31.	14	Post-2016	0	1,449,017					
32.	14.1	Pre-2017 (formerly ECE)	0	2,022,836,267					
33.	14.1		0	56,604,759					

	1 Class number	Description	9 Proceeds of dispositions Note 8 207	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 6 **minus** column 9) Note 9	11 Proceeds of dispositions available to reduce additions of AIIP, RIIP and property included in Classes 54 to 56 (column 7 **plus** column 9 **minus** column 3 **plus** column 4 **plus** column 5 **minus** column 8) (if negative, enter "0")	12 Net capital cost additions of AIIP and property acquired before 2025 that is included in Classes 54 to 56 (column 4 **minus** column 11) (if negative, enter "0")	13 Proceeds of dispositions from column 11 available to reduce additions of RIIP and ZEV acquired after 2024 that is included in Classes 54 to 56 (column 11 **minus** column 4) (if negative, enter "0")	14 Net capital cost additions of RIIP and property acquired after 2024 that is included in Classes 54 to 56 (column 5 **minus** column 13) (if negative, enter "0")	15 UCC adjustment for AIIP and property acquired before 2025 that is included in Classes 54 to 56 (column 12 **multiplied** by the relevant factor) Note 10
34.	17		421,694	350,048,186	421,694	19,518,951		16,470,752	
35.	42		2,600,000	44,997,629					
36.	43.1		0	215,021					
37.	43.2		0	61					
38.	45		0	151,817					
39.	46		0	12,215,896		578,931		86,481	1,350,839
40.	47		11,985,575	13,170,861,827	11,985,575	903,411,372		1,175,932,421	
41.	50		131,341	44,042,755	131,341	10,479,909		15,877,064	8,574,473
42.	54		0	3,870,068				2,756,818	
		Totals	22,027,645	22,821,392,614	19,427,645	1,108,521,608		1,462,632,314	9,925,312

	1 Class number	Description	16 UCC adjustment for RIIP and property acquired after 2024 that is included in Classes 54 to 56 (column 14 **multiplied** by the relevant factor) Note 11	17 UCC adjustment for property acquired during the year other than AIIP, RIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 5 **plus** column 8 **minus** column 7 **minus** column 9) (if negative, enter "0") Note 12 224	18 CCA rate % Note 13 212	19 Recapture of CCA Note 14 213	20 Terminal loss Note 15 215	21 CCA (for declining balance method, the result of column 10 **plus** column 15 **plus** column 16 **minus** column 17, **multiplied** by column 18 or a lower amount) Note 16 217	22 UCC at the end of the year (column 10 **minus** column 21) 220
1.	1		55,213,921		4	0	0	180,394,127	4,274,245,121
2.	1b				6	0	0	1,511	23,679
3.	2				6	0	0	110,845,245	1,736,575,508
4.	3		5,208		5	0	0	10,268,353	195,093,492
5.	6		1,610,414		10	0	0	7,847,757	69,019,402
6.	7				15	0	0	253,649	1,437,341
7.	8		9,743,943		20	0	0	51,410,339	195,897,415

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	1 Class number	Description	16 UCC adjustment for RIIP and property acquired after 2024 that is included in Classes 54 to 56 (column 14 **multiplied** by the relevant factor) **Note 11**	17 UCC adjustment for property acquired during the year other than AIIP, RIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 5 **plus** column 8 **minus** column 7 **minus** column 9) (if negative, enter "0") **Note 12** **224**	18 CCA rate % **Note 13** **212**	19 Recapture of CCA **Note 14** **213**	20 Terminal loss **Note 15** **215**	21 CCA (for declining balance method, the result of column 10 **plus** column 15 **plus** column 16 **minus** column 17, **multiplied** by column 18 or a lower amount) **Note 16** **217**	22 UCC at the end of the year (column 10 **minus** column 21) **220**
8.	9		2,271,646		25	0	0	5,361,587	13,813,113
9.	10	Class 10.1	4,166,626		30	0	0	7,579,678	13,519,288
10.	10		11,878,126		30	0	0	33,643,827	66,624,137
11.	12				100	0	0	127,771,006	
12.	13	2300 Yonge St (WBS 700052298)			NA	0	0	95,382	20,765
13.	13	420 Welham Rd Barrie (WBS 700060775)			NA	0	0	4,278	6,416
14.	13	483 Bay Street (WBS 300040950)			NA	0	0	20,815	125,576
15.	13	483 Bay Street (WBS 300042991C/7000015844/843			NA	0	0	1,624,028	903,816
16.	13	483 Bay Street ELT 8th Floor (WBS 700063162)			NA	0	0	158,028	553,096
17.	13	Alliston OC (WBS 700050153)			NA	0	0	1,781	13,329
18.	13	Barrie Corporate Office (WBS 700050155)			NA	0	0	7,155	3,656
19.	13	BASC office reno (WBS 700057942)			NA	0	0	37,584	56,375
20.	13	Bracebridge Forestry (WBS 700050490)			NA	0	0	2,247	5,640
21.	13	Newmarket SC (WBS 700016578/700052236)			NA	0	0	5,650	31,108
22.	13	PCB Light Replacement			NA	0	0	794	
23.	13	Smart Meter Facility - 255 Matheson Blvd Miss			NA	0	0	763,922	2,021,012
24.	13	Sudbury (WBS 700010356)			NA	0	0	14,123	
25.	13	Sudbury 500 Barrydowne (WBS 700025393)			NA	0	0	2,273	
26.	13	Switch to LED fixtures/light bulbs			NA	0	0	58,304	10,183
27.	13	Thunder Bay Fleet Garage (WBS 7000032535)			NA	0	0	135,329	2,044,708
28.	13	Timmins OC 569-571 Moneta Dr (WBS 700052236)			NA	0	0	3,304	4,992
29.	13	Timmins Fleet Garage Auto Gate (WBS 700057953			NA	0	0	119,028	178,678
30.	13	Woodstock office 763 Athlone Dr WBS 700042562			NA	0	0	360,906	3,079,455
31.	14	Post-2016			NA	0	0	74,023	1,374,994
32.	14.1	Pre-2017 (formerly ECE)			5	0	0	141,598,538	1,881,237,729
33.	14.1				5	0	0	2,830,238	53,774,521
34.	17		8,235,376		8	0	0	28,662,685	321,385,501
35.	42				12	0	0	5,399,715	39,597,914
36.	43.1				30	0	0	64,506	150,515

	1 Class number	Description	16 UCC adjustment for RIIP and property acquired after 2024 that is included in Classes 54 to 56 (column 14 **multiplied** by the relevant factor) **Note 11**	17 UCC adjustment for property acquired during the year other than AIIP, RIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 5 **plus** column 8 **minus** column 7 **minus** column 9) (if negative, enter "0") **Note 12** 224	18 CCA rate % **Note 13** 212	19 Recapture of CCA **Note 14** 213	20 Terminal loss **Note 15** 215	21 CCA (for declining balance method, the result of column 10 **plus** column 15 **plus** column 16 **minus** column 17, **multiplied** by column 18 or a lower amount) **Note 16** 217	22 UCC at the end of the year (column 10 **minus** column 21) 220
37.	43.2				50	0	0	31	30
38.	45				45	0	0	68,318	83,499
39.	46		201,789		30	0	0	4,130,557	8,085,339
40.	47		587,966,211		8	0	0	1,100,706,243	12,070,155,584
41.	50		12,990,328		55	0	0	36,084,156	7,958,599
42.	54		6,432,575		30	0	0	3,090,793	779,275
		Totals	700,716,163					1,861,501,813	20,959,890,801

Enter the total of column 19 on line 107 of Form T2 SCH 1, Net Income (Loss) for Income Tax Purposes.
Enter the total of column 20 on line 404 of Form T2 SCH 1.
Enter the total of column 21 on line 403 of Form T2 SCH 1.

Notes

Note 1: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 2: Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exclusions from the half-year rule. Do not include any amount in column 3 in respect of property included in column 6 (Note 5). See Guide T4012 for more information about the cost of acquisitions during the year.

Note 3: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018 and before 2025, and that became available for use before 2028.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2034.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that you acquired after March 1, 2020, and that became available for use before 2034.

See Guide T4012 for more information.

Note 4: An RIIP is a property (other than property included in Classes 54 to 56) that you acquired after 2024, and that became available for use before 2034.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2034.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that you acquired after March 1, 2020, and that became available for use before 2034.

See Guide T4012 for more information.

Note 5: Enter in column 6, "Adjustments and transfers," amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See Guide T4012 for other examples of adjustments and transfers to include in column 6.

Also include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 6: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 7: Include all amounts you have repaid during the year for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 8: For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a designated immediate expensing property) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 9: If the amount in column 6 (as shown in brackets) reduces the UCC, you must subtract it for the purpose of the calculation. Otherwise, add the amount in column 6 for the purpose of the calculation.

Note 10: The adjustment from column 15 is added to the UCC in column 10 to calculate the CCA deduction in column 21.

The relevant factors for property of a class in Schedule II, that is an AIIP or property acquired before 2025 that is included in Classes 54 to 56, are:

- 1 1/2 for property in Classes 43.1, 54 and 56 that became available for use in 2024 or 2025 or 5/6 if it became available for use after 2025
- 7/8 for property in Class 55 that became available for use in 2024 or 2025 or 3/8 if it became available for use after 2025
- 1/2 for property in Classes 43.2 and 53 that became available for use in 2024 or 2025 or 1/10 if it became available for use after 2025
- 3 for property in Class 44 that was acquired and became available for use after April 15, 2024 and before 2027 or 0 if it became available for use after 2026
- 2 1/3 for property in Class 46 that was acquired and became available for use after April 15, 2024 and before 2027 or 0 if it became available for use after 2026
- 9/11 for property in Class 50 that was acquired and became available for use after April 15, 2024 and before 2027 or 0 if it became available for use after 2026
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 16 for additional information)
- 0 for all other property (including property in Class 10.1) that is an AIIP (other than property in Classes 44, 46 or 50) that became available for use after 2023

If the tax year does not follow the calendar year, the relevant factor is determined under subsection 1100(2.01) of the Regulations.

Notes (continued)

Note 11: The adjustment from column 16 is added to the UCC in column 10 to calculate the CCA deduction in column 21.

The relevant factors for property of a class in Schedule II, that is an RIIP or property acquired after 2024 that is included in Classes 54 to 56, are:

- 2 1/3 for property in Classes 43.1, 54 and 56 that became available for use before 2030
- 1 1/2 for property in Class 55 that became available for use before 2030
- 1 for property in Class 53
- 2 1/3 for property in Class 43 acquired after 2025 that became available for use before 2030, if such property would have been included in Class 53 if it had been acquired in 2025
- 3 for property in Class 44 that became available for use before 2027 or 0 if it became available for use after 2026
- 2 1/3 for property in Class 46 that became available for use before 2027 or 0 if it became available for use after 2026
- 9/11 for property in Class 50 that became available for use before 2027 or 0 if it became available for use after 2026
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 16 for additional information)
- 0.5 for all other property (including property in Class 10.1) that is an RIIP that became available for use before 2030 or 0 if it became available for use after 2029

If the tax year does not follow the calendar year, the relevant factor is determined under subsection 1100(2.011) of the Regulations.

Note 12: The UCC adjustment for property acquired during the year (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP, RIIP and property included in Classes 54 to 56). For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance. The adjustment from column 17 is subtracted from the UCC in column 10 to calculate the CCA deduction in column 21.

Note 13: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter "N/A". Then enter the amount you are claiming in column 21.

Note 14: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 19 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a designated immediate expensing property.

Note 15: If no property is left in the class at the end of the tax year and there is still a positive amount in the column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 20. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 16: If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4012 for more information.

For property in Class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year.

For AIIP and RIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: if the capital cost of the RIIP was incurred before 2030, the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction), and in any other case, the amount for the year calculated in accordance with Schedule III of the Regulations
- Class 14: the lesser of 150% (if the property is an RIIP that becomes available for use in the year and before 2030) or 125% (if the property is an AIIP that becomes available for use in the year and after 2023 or an RIIP that becomes available for use in the year and after 2029) of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% (if the property is an RIIP acquired in the year and before 2026) or 125% (if the property is an AIIP acquired in the year and after 2023 or an RIIP acquired in the year and after 2025) of an amount calculated on the basis of a rate per cord, board foot, or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% (for RIIP acquired in the year and before 2030) or 33 1/3% (in any other case) of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Natural gas liquefaction: The additional allowances in respect of natural gas liquefaction under paragraphs 1100(1)(a.3) and (yb) of the Regulations are eligible for the accelerated investment incentive and the reaccelerated investment incentive.

The AIIP and RIIP provisions also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to an industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more details.

Fixed Assets Reconciliation

Reconciliation of change in fixed assets per financial statements to amounts used per tax return.

Tax return

Additions for tax purposes – Schedule 8 regular classes		2,589,473,127		
Additions for tax purposes – Schedule 8 leasehold improvements	+	1,108,440		
Operating leases capitalized for book purposes	+			
Capital gain deferred	+			
Recapture deferred	+			
Deductible expenses capitalized for book purposes – Schedule 1	+	422,026,580		
Other (specify):				
CCRA true up credited to fixed assets	+	-3,612,071		
Land and landscaping adjustments	+	5,435,975		
Project cancellation costs expensed for book purposes	+	-10,193,080		
Disallowed Class 10.1 Additions	+	8,721,410		
Removal costs (cap for tax but deduct for accounting)	+	-158,969,864		
Future use assets movement	+	-12,034,000		
In-serviced cloud computing costs	+	-34,378,944		
Total additions per books	=	2,807,577,573	▶	2,807,577,573
Proceeds up to original cost – Schedule 8 regular classes		22,027,645		
Proceeds up to original cost – Schedule 8 leasehold improvements	+			
Proceeds in excess of original cost – capital gain	+			
Recapture deferred – as above	+			
Capital gain deferred – as above	+			
Pre V-day appreciation	+			
Other (specify):				
Increase in CIP ending (excluded from Sch 8 adds)	+	-446,000,000		
Land NBV disposed	+	575,146		
Reverse capitalized depreciation (incl in depn exp below)	+	35,483,398		
Depreciation with regulatory offset (no NBV impact)	+	1,527,197		
Rounding to FS (prepared in millions)	+	1,036,985		
IRU sale - for tax, reduced UCC	+	-2,600,000		
Total proceeds per books	=	-387,949,629	▶	-387,949,629
Depreciation and amortization per accounts – Schedule 1			–	925,777,202
Loss on disposal of fixed assets per accounts			–	
Gain on disposal of fixed assets per accounts			+	250,000
Net change per tax return			=	2,270,000,000

Financial statements

Fixed assets (excluding land) per financial statements

Closing net book value		30,955,000,000
Opening net book value	–	28,685,000,000
Net change per financial statements	=	2,270,000,000

If the amounts from the tax return and the financial statements differ, explain why below.

Attached Schedule with Total

Tax return – Deductible expenses capitalized for book purposes – Schedule 1

Title Tax return – Deductible expenses capitalized for book purposes – Schedule 1

Explanatory note

Refer to T2 - Fixed Asset Roll (8.0A) and 8.4 Accting to Tax Adds for details.

Description	Operator (Note)	Amount
Capitalized Pension Expenses (8.5 Adds adj)		41,285,580 00
Capitalized Interest Expenses (GL 761401/761402 - 8.5 Adds adj)	+	104,436,929 00
Capitalized Overheads (8.5 Adds adj)	+	171,850,115 00
Capitalized OPEB (8.5 Adds adj)	+	41,133,651 00
Capitalized LTIP Expenses (1.3 LTIP)	+	1,575,260 00
Removal Costs deductible (8.5 Adds adj)	+	18,288,164 00
Union share grant expenses (1.6 Share Grant)	+	4,774,438 00
Capitalized depreciation (8.12 Depn)	+	35,483,398 00
ARO (13.6)	+	2,869,979 00
ARO addition (8.3)	+	329,066 00
	Total	422,026,580 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	Hydro One Limited	CA		3					
2.	Hydro One Inc.	CA		1					
3.	2486267 Ontario Inc.	CA		3					
4.	2486268 Ontario Inc.	CA		3					
5.	Hydro One Remote Communites Inc	CA		3					
6.	Acronym Solutions Inc.	CA		3					
7.	Municipal Billing Services Inc.	CA		3					
8.	Hydro One Lake Erie Link Managem	CA		3					
9.	Hydro One Indigenous Partnerships	CA		3					
10.	Norfolk Energy Inc.	CA		3					
11.	Norfolk Power Distribution Inc.	CA		2					
12.	Haldimand County Energy Inc.	CA		2					
13.	Haldimand County Hydro Inc.	CA		2					
14.	Woodstock Hydro Services Inc.	CA		2					
15.	Hydro One Sault Ste. Marie Holding	CA		3					
16.	Hydro One Sault Ste. Marie Inc.	CA		3					
17.	Hydro One Sault Ste. Marie Holding	CA		3					
18.	1228185 Ontario Inc.	CA		3					
19.	1937680 Ontario Inc.	CA		2					
20.	1937681 Ontario Inc.	CA		3					
21.	2587264 Ontario Inc.	CA		3					
22.	Hydro One Holdings Limited	CA		3					
23.	2587265 Ontario Inc.	CA		3					
24.	Orillia Power Distribution Corporatic	CA		3					
25.	2835785 Ontario Inc.	CA		3					
26.	Aux Energy Inc.	CA		3					
27.	Hydro One Broadband Solutions Inc	CA		3					
28.	1000575868 ONTARIO INC	CA		2					
29.	1000575870 ONTARIO INC.	CA		2					
30.	Chatham x Lakeshore GP Inc	CA		3					
31.	1000878753 Ontario Inc	CA		3					
32.	Nextbridge (Optionco) Inc.	CA		3					
33.	Upper Canada Transmission 2, Inc	CA		3					
34.	Olympus Holding Corp	US		3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

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Schedule 13

Continuity of Reserves

Name of corporation	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- For use by corporations to provide a continuity of all reserves claimed which are allowed for tax purposes.
- File one completed copy of this schedule with the corporation's T2 Corporation Income Tax Return.
- For more information, see the T2 Corporation Income Tax Guide.

Part 1 – Capital gains reserves

	Description of property 001	Balance at the beginning of the year $ 002	Transfer on an amalgamation or the wind-up of a subsidiary $ 003	Add $	Deduct $	Balance at the end of the year $ 004
1						
	Totals	008	009			010

The amount from line 008 **plus** the amount from line 009 should be entered on line 880 of Schedule 6, Summary of Dispositions of Capital Property.
The amount from line 010 should be entered on line 885 of Schedule 6.

Part 2 – Other reserves

Description	Balance at the beginning of the year $	Transfer on an amalgamation or the wind-up of a subsidiary $	Add $	Deduct $	Balance at the end of the year $
Reserve for doubtful debts . . . . . ☐	110	115			120
Reserve for undelivered goods and services not rendered . . . . . ☒	130 63,317,591	135	12,844,403		140 76,161,994
Reserve for prepaid rent . . . . . ☐	150	155			160
Reserve for refundable containers . . . . . ☐	190	195			200
Reserve for unpaid amounts . . . . . ☐	210	215			220
Other tax reserves . . . . . ☐	230	235			240
Totals	270 63,317,591	275	12,844,403		280 76,161,994

The amount from line 270 **plus** the amount from line 275 should be entered on line 125 of Schedule 1, Net Income (Loss) for Income Tax Purposes, as an addition.
The amount from line 280 should be entered on line 413 of Schedule 1 as a deduction.

T2 SCH 13 E (22)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	OPEB Liability LT	1,630,107,924		79,454,097		1,709,562,021
2	Environmental liability LT	9,167,604			6,129,673	3,037,931
3	Reg offset - Environmental liab	-5,811,346		3,567,956		-2,243,390
4	Net Regulatory Liabilities	360,512,559		257,346,483		617,859,042
5	Tenant Inducement	1,535,143			486,611	1,048,532
6	Asset Retirement Obligations	19,143,840		3,497,999		22,641,839
7	Contingent Liabilities	63,997,442			52,503,438	11,494,004
8	Director Share Units (DSU)	15,977,920		200,081		16,178,001
9	Lease Adjustment	215,862			117,668	98,194
10	Reg offset - OPEB Liability Valua	372,671,415			39,368,362	333,303,053
	Reserves from Part 2 of Schedule 13	63,317,591		12,844,403		76,161,994
	Totals	2,530,835,954		356,911,019	98,605,752	2,789,141,221

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

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SCHEDULE 14

MISCELLANEOUS PAYMENTS TO RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- This schedule must be completed by all corporations who made the following payments to residents of Canada: royalties for which the corporation has not filed a T5 slip; research and development fees; management fees; technical assistance fees; and similar payments.
- Please enter the name and address of the recipient and the amount of the payment in the applicable column. If several payments of the same type (i.e., management fees) were made to the same person, enter the total amount paid. If similar types of payments have been made, but do not fit into any of the categories, enter these amounts in the column entitled "Similar payments".

	Name of recipient 100	Address of recipient 200	Royalties 300	Research and development fees 400	Management fees 500	Technical assistance fees 600	Similar payments 700
1	Hydro One Inc	483 Bay Street Toronto ON M5G 2P5			9,488,262		
2	Hydro One Limited	483 Bay Street Toronto ON M5G 2P5			9,433,951		

T2 SCH 14 (99)

Canada

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Schedule 15

Deferred Income Plans

Corporation's name	Business number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Complete the information below if the corporation deducted payments from its income made to a registered pension plan (RPP), a registered supplementary unemployment benefit plan (RSUBP), a deferred profit sharing plan (DPSP), a pooled registered pension plan (PRPP), or an employee profit sharing plan (EPSP).
- If the trust that governs an employee profit sharing plan is **not resident** in Canada, please indicate if the T4PS, *Statement of Employees Profit Sharing Plan Allocations and Payments*, Supplementary slip(s) were filed for the last calendar year, and whether they were filed by the trustee or the employer.

	Type of plan (see note 1) 100	Amount of contribution $ (see note 2) 200	Registration number (RPP, RSUBP, PRPP, and DPSP only) 300	Name of EPSP trust 400	Address of EPSP trust 500	T4PS slip(s) (see note 3) 600
1	1	65,898,571	1059104			

Note 1

Enter the applicable code number:

1 – RPP
2 – RSUBP
3 – DPSP
4 – EPSP
5 – PRPP

Note 2

You do not need to add to Schedule 1 any payments you made to deferred income plans.
To reconcile such payments, calculate the following amount:

Total of all amounts indicated in column 200 of this schedule	65,898,571	A
Less:		
Total of all amounts for deferred income plans deducted in your financial statements	24,612,992	B
Deductible amount for contributions to deferred income plans (amount A **minus** amount B) (if negative, enter "0")	41,285,579	C

Enter amount C on line 417 of Schedule 1

Note 3

T4PS slip(s) filed by: 1 – Trustee
2 – Employer (EPSP only)

T2 SCH 15 (13)

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SCHEDULE 29

PAYMENTS TO NON-RESIDENTS

Name of corporation	Business Number	Tax year end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- A corporation that makes payments or credits amounts to non-residents under subsections 202(1) and 105(1) of the *Income Tax Regulations* has to file the applicable information return.
- The corporation has to complete the information below for all amounts paid or credited to non-residents that are listed in Note 1. If the total amount paid or credited is less than $100, you do not have to complete the information for that payee.

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
1			09	31,880
2			09	16,820
3			02	31,361
4			09	12,247
5			02	30,761
6			02	16,832
7			02	8,611
8			02	21,413
9			09	18,142
10			02	301,529
11			02	5,497

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
12			02	337,874
13			02	46,500
14			02	42,005
15			02	25,056
16			02	22,103
17			02	41,997
18			02	30,814
19			02	26,173
20			09	5,000
21			09	166
22			09	317,760
23			09	14,722
24			09	5,000

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
25			09	11,163
26			09	11,182
27			09	35,651
28			09	67,031
29			09	1,948,053
30			09	12,949
31			09	357,777
32			02	4,863
33			02	2,500
34			02	220,706
35			02	2,500

	Name (list each payee separately) 100	Address 200	Payment code (see note 1) 300	Amount $ 400
36			02	10,000

Note 1: Enter the applicable payment code in column 300:

1 – Royalties
2 – Rents
3 – Management fees/commissions
4 – Technical assistance fees
5 – Research and development fees
6 – Interest
7 – Dividends
8 – Film payments: – motion picture film, or – a film or video tape for use in connection with television
9 – Other services

T2 SCH 29 (99)

Canada

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Schedule 31

Investment Tax Credit – Corporations

General information

- Use this schedule:
  - to calculate an investment tax credit (ITC) earned during the tax year
  - to claim a deduction against Part I tax payable
  - to claim a refund of credit earned during the current tax year
  - to claim a carryforward of credit from previous tax years
  - to transfer a credit following an amalgamation or the wind-up of a subsidiary, as described under subsections 87(1) and 88(1)
  - to request a credit carryback to one or more previous years
  - if you are subject to a recapture of ITC
- Unless otherwise stated, all legislative references are to the Income Tax Act or, where appropriate, the Income Tax Regulations.
- Certain ITCs are eligible for a three-year carryback (if not deductible in the year earned) and are also eligible for a twenty-year carryforward. This does not apply to the clean economy ITCs, which are refundable tax credits.
- Investments or expenditures, described in subsection 127(9) and Regulation Part XLVI, that earn an ITC are:
  - qualified property and qualified resource property (Parts 4 to 7 of this schedule)
    - You can no longer claim the ITC for the qualified resource property expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
  - qualified scientific research and experimental development (SR&ED) expenditures (Parts 8 to 17). File Form T661, Scientific Research and Experimental Development (SR&ED) Expenditures Claim
  - pre-production mining expenditures (Part 18)
    - You can no longer claim the ITC for the pre-production mining expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
  - apprenticeship job creation expenditures (Parts 19 to 21)
  - child care spaces expenditures (Part 22)
    - You can no longer claim the ITC for the child care spaces expenditures. Only unused credits that have not expired can be carried forward for up to 20 tax years following the tax year in which you incurred the expenditures.
- Investments or expenditures for the clean economy, described in sections 127.44, 127.45, 127.48, 127.49, and 127.491 that earn an ITC are investments in (Part 23):
  - carbon capture, utilization, or storage (CCUS) projects, for qualifying expenditures made after 2021
  - clean technology property that is acquired and becomes available for use after March 27, 2023
  - eligible clean hydrogen property that is acquired and becomes available for use after March 27, 2023
  - clean technology manufacturing (CTM) property that is used in qualifying manufacturing and processing activities or the extraction and processing of certain critical minerals and that is acquired and becomes available for use after 2023
  - clean electricity property that is acquired and becomes available for use after April 15, 2024, for projects that did not begin construction before March 28, 2023
- File this schedule with the T2 Corporation Income Tax Return. If you need more space, attach additional schedules.
- For more information on ITCs, see **Investment Tax Credits** in Guide T4012, T2 Corporation – Income Tax Guide.
- For more information on SR&ED, see Guide T4088, Scientific Research and Experimental Development (SR&ED) Expenditures Claim – Guide to Form T661.

Detailed information

- For the purpose of this schedule, **investment** generally means the capital cost of the property (excluding amounts added by an election under section 21), determined without reference to subsections 13(7.1) and 13(7.4), minus the amount of any government or non-government assistance that the corporation has received, is entitled to receive, or can reasonably be expected to receive for that property at the time it files the income tax return for the year in which the property was acquired. For rules related to capital cost for the CCUS ITC, clean technology ITC, clean hydrogen ITC, clean technology manufacturing ITC, and clean electricity ITC, see, respectively, subsections 127.44(9), 127.45(5), 127.48(10), 127.49(5), and 127.491(9).
- An ITC deducted in a tax year for a depreciable property reduces both the capital cost of that property and the undepreciated capital cost of that class in the next tax year. An ITC for SR&ED deducted or refunded in a tax year will reduce the balance in the pool of deductible SR&ED expenditures and the adjusted cost base (ACB) of an interest in a partnership in the next tax year. An ITC from pre-production mining expenditures deducted in a tax year reduces the balance in the pool of deductible cumulative Canadian exploration expenses in the next tax year.
- Property acquired has to be **available for use (AFU)** before a claim for an ITC can be made. See subsections 127(11.2), 127.45(4), 127.48(5), 127.49(4), 127.491(7), and 248(19) for more information. The AFU rules do not apply to claims for the CCUS ITC.
- Current and capital expenditures for SR&ED qualifying for an ITC must be identified by the claimant on Form T661, and the related SR&ED ITC must be reported on Schedule 31, no later than one year after the claimant's income tax return is due for the tax year in which it incurred the expenditures or acquired the property. A claimant that does not meet this reporting deadline will not be able to file Schedule 508, Ontario Research and Development Tax Credit, and Schedule 566, Ontario Innovation Tax Credit.
- Expenditures for an apprenticeship ITC must be identified by the claimant on Schedule 31 no later than one year after the claimant's income tax return is due for the tax year in which it incurred the expenditures.
- The claimant must identify the clean economy ITC on Schedule 31 the later of one year after the claimant's income tax return is due for the tax year it is entitled to claim the credit for and December 31, 2026.

Detailed information (continued)

- Partnership allocations – Subsection 127(8) provides for the allocation of the amount that may reasonably be considered to be a partner's share of the ITCs of the partnership at the end of the fiscal period of the partnership. An allocation of ITCs is generally considered to be the partner's reasonable share of the ITCs if it is made in the same proportion in which the partners have agreed to share any income or loss and if section 103 is not applicable for the agreement to share any income or loss. Special rules apply to specified members of a partnership and limited partners. For more information, see Guide T4068, Guide for the Partnership Information Return (T5013 Forms). See section 127.47 for rules that apply to partnerships for the clean economy ITCs generally. For more information on partnership allocations for the CCUS ITC, clean technology ITC, clean hydrogen ITC, clean technology manufacturing ITC, and clean electricity ITC, see, respectively, subsections 127.44(11), 127.45(8), 127.48(12), 127.49(8), and 127.491(12).
- For certain purposes, Canada includes the **exclusive economic zone of Canada** as defined in the Oceans Act (which generally consists of an area of the sea that is within 200 nautical miles from the Canadian coastline), including the airspace, seabed and subsoil of that zone. For the clean technology ITC, Canada includes the exclusive economic zone of Canada only for property that is described in subparagraph (d)(v) or (xiv) of Class 43.1 in Schedule II of the Regulations.
- For the purpose of this schedule, the expression **Atlantic Canada** includes the Gaspé Peninsula and the provinces of Newfoundland and Labrador, Prince Edward Island, Nova Scotia, and New Brunswick, as well as their respective offshore regions (prescribed in Regulation 4609).
- For the purpose of this schedule, **qualified property** means property in Atlantic Canada that is used primarily for manufacturing and processing, farming or fishing, logging, storing grain, or harvesting peat. Qualified property includes new buildings and new machinery and equipment (prescribed in Regulation 4600), and new energy generation and conservation property (prescribed in Regulation 4600). Certain qualified property can also be used primarily to produce or process electrical energy or steam in a prescribed area (as described in Regulation 4610). See the definition of **qualified property** in subsection 127(9) for more information.

Part 1 – Investments, expenditures and percentages

Investments	Specified percentage
Qualified property and qualified resource property (Part 5)	
Qualified property acquired primarily for use in Atlantic Canada	10 %
Expenditures	
If you are a Canadian-controlled private corporation (CCPC) or, for tax years starting after December 15, 2024, an eligible Canadian public corporation (ECPC) as defined in subsection 127(9), this percentage may apply to the portion that you claim of the SR&ED qualified expenditure pool that does not exceed your expenditure limit (see Part 10)	35 %
Note: If your current year's qualified expenditures are more than your expenditure limit (see Part 10), the excess is eligible for an ITC calculated at the 15 % rate.	
For tax years starting before December 16, 2024, if you are a corporation that is not a CCPC and have incurred qualified expenditures for SR&ED in any area in Canada.	15 %
If you paid salary and wages to apprentices in the first 24 months of their apprenticeship contract for employment	10 %
Clean economy ITCs (Part 23)	
For work performed after November 27, 2023, to qualify for the investment tax credit rates indicated below, an incentive claimant must elect (in prescribed form) to meet certain labour requirements – prevailing wage requirements and apprenticeship requirements. Otherwise, the credit rate will be reduced by 10 percentage points. The incentive claimant must also attest (in prescribed form) to have met these requirements. The labour requirements do not apply to the clean technology manufacturing ITC.	
CCUS	
If you incurred qualified carbon capture expenditures to capture carbon directly from ambient air:	
after 2021 and before 2036	60%
after 2035 and before 2041	30%
If you incurred qualified carbon capture expenditures to capture carbon other than directly from ambient air:	
after 2021 and before 2036	50%
after 2035 and before 2041	25%
If you incurred qualified expenditures for carbon transportation, use, or storage:	
after 2021 and before 2036	37.5%
after 2035 and before 2041	18.75%
Clean technology	
If you acquired clean technology property after March 27, 2023, and it becomes available for use:	
before 2034	30%
in 2034	15%
Clean hydrogen	
If you acquired an eligible clean hydrogen property after March 27, 2023, and it becomes available for use:	
before 2034	depending on the carbon intensity tier 40%, 25% or 15%
in 2034	depending on the carbon intensity tier 20%, 12.5%, or 7.5%
For clean ammonia equipment or certain other equipment used solely in connection with clean ammonia equipment, the rate is 15% if the equipment becomes available for use before 2034 and 7.5% if it becomes available for use in 2034.	
Clean technology manufacturing	
If you acquired CTM property after 2023 and it becomes available for use:	
before 2032	30%
in 2032	20%
in 2033	10%
in 2034	5%
Clean electricity	
If you acquired clean electricity property after April 15, 2024, and it becomes available for use before 2035	15%

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Part 2A – Determination of a qualifying corporation

This section does not apply to the clean economy investment tax credits.

Is the corporation a qualifying corporation? . . . . . **101** Yes ☐ No ☒

Enter your taxable income for the previous tax year[1] (prior to any loss carrybacks applied) . . . . . **390** _____

For the purpose of a refundable ITC, a **qualifying corporation** is defined under subsection 127.1(2). The corporation has to be a CCPC and its taxable income (before any loss carrybacks) for its previous tax year cannot be more than its **qualifying income limit** for the particular tax year. If the corporation is associated with any other corporations during the tax year, the total of the taxable incomes of the corporation and the associated corporations (before any loss carrybacks), for their last tax year ending in the previous calendar year, cannot be more than their qualifying income limit for the particular tax year.

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered **not** associated for the calculation of a refundable ITC if both of the following conditions are met:

- one corporation is associated with another corporation only because one or more persons own shares of the capital stock of both corporations
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a **qualifying** corporation, you will earn a **100**% refund on your share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the **40%** refund.

Some CCPCs that are **not qualifying** corporations may also earn a **100**% refund on their share of any ITCs earned at the 35% rate on qualified current expenditures for SR&ED, up to the allocated expenditure limit. The expenditure limit can be determined in Part 10. The 100% refund does not apply to qualified capital expenditures eligible for the 35% credit rate. They are only eligible for the 40% refund.[2]

[1] If the tax year referred to on line 390 is less than 51 weeks, **multiply** the taxable income by the following result: 365 **divided** by the number of days in that tax year.

[2] Only capital expenditures incurred after December 15, 2024, are qualified SR&ED expenditures and eligible for an ITC.

Part 2B – Determination of an excluded corporation – SR&ED

Is the qualifying corporation an excluded corporation as defined under subsection 127.1(2)? . . . . . **650** Yes ☐ No ☒

Only a 40% refund will be available to a qualifying corporation that is an **excluded corporation** as defined under subsection 127.1(2). A corporation is an excluded corporation if, at any time during the year, it is a corporation that is either controlled by (directly or indirectly, in any manner whatever) or is related to one of the following:

a) one or more persons exempt from Part I tax under section 149

b) His Majesty in right of a province, a Canadian municipality, or any other public authority

c) any combination of persons referred to in a) or b) above

Part 3 – Corporations in the farming industry

Complete this area if the corporation is making SR&ED contributions.

Is the corporation claiming a contribution in the current year to an agricultural organization whose goal is to finance SR&ED work (for example, check-off dues)? . . . . . **102** Yes ☐ No ☒

If **yes**, complete Schedule 125, Income Statement Information, to identify the type of farming industry the corporation is involved in.

Contributions to agricultural organizations for SR&ED[3] . . . . . _____ x 80 % = **103** _____

Include on line 350 of Part 8.

[3] Enter only contributions not already included on Form T661.

Qualified Property and Qualified Resource Property

Part 4 – Eligible investments for qualified property from the current tax year

Capital cost allowance class number **105**	Description of investment **110**	Date available for use **115**	Location used in Atlantic Canada (province) **120**	Amount of investment **125**

Total of investments for qualified property _____ 4A

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Part 5 – Current-year credit and account balances – ITC from investments in qualified property and qualified resource property

ITC at the end of the previous tax year				5A
Credit deemed as a remittance of co-op corporations	210			
Credit expired	215			
Subtotal (line 210 **plus** line 215)			▶	5B
ITC at the beginning of the tax year (amount 5A **minus** amount 5B)		220		
Credit transferred on an amalgamation or the wind-up of a subsidiary	230			
ITC from repayment of assistance	235			
Qualified property (amount 4A) x 10 % =	240			
Credit allocated from a partnership	250			
Subtotal (total of lines 230 to 250)			▶	5C
Total credit available (line 220 **plus** amount 5C)				5D
Credit deducted from Part I tax	260			
Credit carried back to previous years (amount 6A)			5E	
Credit transferred to offset Part VII tax liability	280			
Subtotal (total of line 260, amount 5E, and line 280)			▶	5F
Credit balance before refund (amount 5D **minus** amount 5F)				5G
Refund of credit claimed on investments from qualified property (from Part 7)		310		
ITC closing balance of investments from qualified property and qualified resource property (amount 5G **minus** line 310)		320		

Part 6 – Request for carryback of credit from investments in qualified property

	Year	Month	Day			
1st previous tax year				Credit to be applied	901	
2nd previous tax year				Credit to be applied	902	
3rd previous tax year				Credit to be applied	903	
				Total of lines 901 to 903 Enter at amount 5E.		6A

Part 7 – Refund of ITC for qualifying corporations on investments from qualified property

Current-year ITCs (line 240 **plus** line 250 in Part 5)	7A
Credit balance before refund (from amount 5G)	7B
Refund (40 % of amount 7A or 7B, whichever is less)	7C

Enter amount 7C or a lesser amount on line 310 in Part 5 (also include in line 780 of the T2 return if you do not claim an SR&ED ITC refund).

SR&ED

Part 8 – Qualified SR&ED expenditures

Qualified SR&ED expenditures (line 557 on Form T661)				
Contributions to agricultural organizations for SR&ED				
Deduct:				
Government assistance, non-government assistance, or contract payment				
Subtotal				
x 80 %				
Contributions to agricultural organizations for SR&ED for the federal ITC (this amount is updated to line 103 of Part 3. For more details, consult the Help.)[4]	+ ▶			
Current expenditures (line 557 on Form T661 **plus** line 103 in Part 3)[4]	▶	350		
Capital expenditures incurred after December 15, 2024 (from line 558 on Form T661)		360		
Repayments made in the year (from line 560 on Form T661)		370		
Total qualified SR&ED expenditures (total of lines 350 to 370)		380		

[4] If you are claiming only contributions made to agricultural organizations for SR&ED, line 350 should equal line 103 in Part 3. Do not file Form T661.

Part 9 – Components of the SR&ED expenditure limit calculation

Part 9 applies if you are a CCPC or for tax years starting (TYS) after December 15, 2024, an ECPC.

Are you an ECPC as defined in subsection 127(9)? . . . . . **382** Yes ☐ No ☐

Are you a CCPC electing under subsection 127(10.31) or (10.32) to determine the SR&ED expenditure limit based on revenue? . . . . . **383** Yes ☐ No ☐

Note: A CCPC considered associated with another corporation under subsection 256(1) will be considered not associated for the calculation of an SR&ED expenditure limit if both of the following apply:

- one corporation is associated with another corporation solely because one or more persons own shares of the capital stock of the corporation
- one of the corporations has at least one shareholder who is not common to both corporations

If you are a CCPC that is not electing to determine its expenditure limit under 127(10.31) or (10.32), fill out lines 385 and 398, if applicable.

Is the corporation associated with another CCPC for the purpose of calculating the SR&ED expenditure limit? . . . . . **385** Yes ☐ No ☐

If you answered **no** to the question on line 385 or if you are not associated with any other corporations, complete line 398.

If you answered **yes**, complete Schedule 49, Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Expenditure Limit, to determine the amounts for associated corporations.

For a CCPC, enter your taxable capital employed in Canada for the previous tax year **minus** $10 million (minus $15 million for TYS after December 15, 2024). If this amount is nil or negative, enter "0". If this amount is over $40 million, enter $40 million. For TYS after December 15, 2024, if this amount is over $60 million, enter $60 million . . . . **398** _____

If you are an ECPC, or a CCPC that is electing to determine its expenditure limit under 127(10.31) or (10.32), fill out new line 399.

For an ECPC, or a CCPC filing an election under 127(10.31), enter your average annual revenue from the three fiscal years immediately preceding and ending before this tax year, **minus** $15 million. For a CCPC filing an election under 127(10.32), enter the total of each member's three-year average annual revenue **minus** $15 million (with required partnership/trust/ single-economic-entity adjustments) for the three fiscal year periods ending in the last calendar year that ended before the end of the tax year. If you are an ECPC that is a member of a consolidated group, enter the average, over the period of three fiscal years immediately preceding and ending in the last calendar year that ended before the end of the particular tax year, of the annual revenue of the consolidated group, **minus** $15 million.[5] If this amount is nil or negative, enter "0". If this amount is over $60 million, enter $60 million . . . . . **399** _____

[5] If any relevant fiscal year is less than 51 weeks, gross up revenue by multiplying by 365 and dividing by the number of days in that fiscal year. If there are fewer than three relevant fiscal years, calculate the average over the actual number of fiscal years.

Part 10A – SR&ED expenditure limit for a CCPC with a TYS before December 16, 2024

For a stand-alone (not associated) corporation

$ 40,000,000 **minus** line 398 . . . . . _____ 10A

Amount 10A divided by $ 40,000,000 . . . . . _____ 10B

Expenditure limit for the stand-alone corporation ($ 3,000,000 **multiplied** by amount 10B)[6] . . . . . _____ 10C

For an associated corporation

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49[6] . . . . . **400** _____

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount 10C or line 400 _____ x Number of days in the tax year / 365 = 365 . . . . . _____ 10D

Your SR&ED expenditure limit for the year (enter amount 10C, line 400, or amount 10D, whichever applies) . . . . . **410** _____

[6] Amount 10C or line 400 cannot be more than $3,000,000.

Part 10B – SR&ED expenditure limit for TYS after December 15, 2024, for a CCPC or an ECPC

For a stand-alone (not associated) corporation

$ 60,000,000 **minus** line 398 or, for CCPCs filing an election under 127(10.31) or for ECPCs, **minus** line 399 . . . . . _____ 10A

Amount 10A **divided** by $ 60,000,000 . . . . . _____ 10B

Expenditure limit for the stand-alone corporation ($ 6,000,000 **multiplied** by amount 10B)[7] . . . . . _____ 10C

For an associated corporation

If associated, the allocation of the SR&ED expenditure limit, as provided on Schedule 49[7] . . . . . **400** _____

If your tax year is less than 51 weeks, calculate the amount of the expenditure limit as follows:

Amount 10C or line 400 _____ x Number of days in the tax year / 365 = 365 . . . . . _____ 10D

Your SR&ED expenditure limit for the year (enter amount 10C, line 400, or amount 10D, whichever applies) . . . . . **410** _____

[7] Amount 10C or line 400 cannot be more than $6,000,000.

Part 11 – Investment tax credits on SR&ED expenditures

Current SR&ED expenditures (from line 350 in Part 8) or the expenditure limit (from line 410), whichever is less[8]	420		x	35 %	=		11A
Line 350 **minus** line 410 (if negative, enter "0")	430		x	15 %	=		11B
Line 410 **minus** line 350 (if negative, enter "0")							11C
Capital expenditures incurred after December 15, 2024 (from line 360 in Part 8) or amount 11C above, whichever is less	440		x	35 %	=		11D
Line 360 **minus** amount 11C above (if negative, enter "0")	450		x	15 %	=		11E

If a corporation makes a repayment of any government or non-government assistance, or contract payments that reduced the amount of qualified expenditures for ITC purposes, the amount of the repayment is eligible for a credit.

Repayments (amount from line 370 in Part 8) ____

Enter the amount of the repayment on the line that corresponds to the appropriate rate.

Repayment of assistance that reduced a qualifying expenditure eligible for the 35% SR&ED ITC rate[9]	460		x	35 %	=		11F
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred before 2015	480		x	20 %	=		11G
Repayment of assistance made after September 16, 2016, that reduced a qualifying expenditure incurred after 2014	490		x	15 %	=		11H
Subtotal (total of amounts 11F to 11H)					▶		11I
Current-year SR&ED ITC (total of amounts 11A, 11B, 11D, 11E, and 11I; enter on line 540 in Part 12)							11J

[8] For TYS before December 16, 2024, for corporations that are not CCPCs, enter "0" for amount 11A. For TYS after December 15, 2024, if the corporation is neither a CCPC nor an ECPC, enter “0” for amount 11A.

[9] If you were a CCPC or, for TYS after December 15, 2024, an ECPC, this percentage was applied to the portion that you claimed of the SR&ED qualified expenditure pool that did not exceed your expenditure limit at the time. This percentage includes the rate under subsection 127(10.1), **Additions to investment tax credit**. See subsection 127(10.1) for details about exceptions. For expenditures not eligible for this rate use line 480 or 490 as appropriate.

Part 12 – Current-year credit and account balances – ITC from SR&ED expenditures

ITC at the end of the previous tax year				12A
Credit deemed as a remittance of co-op corporations	510			
Credit expired	515			
Subtotal (line 510 **plus** line 515)			▶	12B
ITC at the beginning of the tax year (amount 12A **minus** amount 12B)		520		
Credit transferred on an amalgamation or the wind-up of a subsidiary	530			
Total current-year credit (from amount 11J)	540			
Credit allocated from a partnership	550			
Subtotal (total of lines 530 to 550)			▶	12C
Total credit available (line 520 **plus** amount 12C)				12D
Credit deducted from Part I tax	560			
Credit carried back to previous years (amount 13A)				12E
Credit transferred to offset Part VII tax liability	580			
Subtotal (line 560 **plus** amount 12E **plus** line 580)			▶	12F
Credit balance before refund (amount 12D **minus** amount 12F)				12G
Refund of credit claimed on SR&ED expenditures (from Part 14 or 15, whichever applies)		610		
ITC closing balance on SR&ED (amount 12G **minus** line 610)		620		

Part 13 – Request for carryback of credit from SR&ED expenditures

	Year	Month	Day
1st previous tax year			
2nd previous tax year			
3rd previous tax year			

Credit to be applied **911** _____

Credit to be applied **912** _____

Credit to be applied **913** _____

Total of lines 911 to 913 _____ 13A
Enter at amount 12E.

Part 14 – Refund of ITC for qualifying corporations – SR&ED

Complete this part if you are a qualifying corporation as determined on line 101 in Part 2A.[10]

Current-year ITC (lines 540 **plus** 550 in Part 12 **minus** amount 11I)		14A
Refundable credits (amount 14A or amount 12G, whichever is less)		14B
Amount 14B or amount 11A, whichever is less		14C
Net amount (amount 14B **minus** amount 14C; if negative, enter "0")		14D
Amount 14D **multiplied** by	40 %	14E
Amount 14C		14F
Refund of ITC (amount 14E **plus** amount 14F – enter this, or a lesser amount, on line 610 in Part 12)		14G

Include the total of line 310 in Part 5 and line 610 in Part 12 in line 780 of the T2 return.

[10]If you are also an excluded corporation, as determined in Part 2B, amount 14B must be multiplied by 40%. Claim this, or a lesser amount, as your refund of ITC for amount 14G.

Part 15 – Refund of ITC for CCPCs that are neither qualifying nor excluded corporations and ECPCs with TYS after December 15, 2024 – SR&ED

Complete this part only if you are a CCPC that is not a qualifying corporation as determined on line 101 in Part 2A, an excluded corporation as determined on line 650 in Part 2B, or an ECPC with TYS after December 15, 2024.

Credit balance before refund (amount 12G)		15A
Amount 15A or amount 11A, whichever is less		15B
Net amount (amount 15A **minus** amount 15B; if negative, enter "0")		15C
Amount 15C or amount 11D, whichever is less		15D
Amount 15D **multiplied** by	40 %	15E
Amount 15B		15F
Refund of ITC (amount 15E **plus** amount 15F)		15G

Enter amount 15G, or a lesser amount, on line 610 in Part 12 and also include it in line 780 of the T2 return.

Recapture – SR&ED

Part 16 – Recapture of ITC for corporations and partnerships – SR&ED

You will have a recapture of ITC in a year when **all** of the following conditions are met:

- you acquired a particular property in the current year or in any of the 20 previous tax years, and the credit was earned in a tax year ending after 1997 and did not expire before 2008
- you claimed the cost of the property as a qualified expenditure for SR&ED on Form T661
- the cost of the property was included in calculating your ITC or was the subject of an agreement made under subsection 127(13) to transfer qualified expenditures
- you disposed of the property or converted it to commercial use after February 23, 1998. This condition is also met if you disposed of or converted to commercial use a property that incorporates the particular property previously referred to

Note:

The recapture **does not apply** if you disposed of the property to a non-arm's-length purchaser who intended to use it all or substantially all for SR&ED. When the non-arm's-length purchaser later sells or converts the property to commercial use, the recapture rules will apply to the purchaser based on the historical ITC rate of the original user.

You will report a recapture on the T2 return for the year in which you disposed of the property or converted it to commercial use. In the following tax year, add the amount of the ITC recapture to the SR&ED expenditure pool.

If you have more than one disposition for calculations 1 and 2, complete the columns for each disposition for which a recapture applies, using the calculation formats below.

Calculation 1 – If you meet all of the above conditions

Amount of ITC you originally calculated for the property you acquired, or the original user's ITC where you acquired the property from a non-arm's length party, as described in the **note** above **700**	Amount calculated using ITC rate at the date of acquisition (or the original user's date of acquisition) on either the proceeds of disposition (if sold in an arm's length transaction) or the fair market value of the property (in any other case) **710**	Amount from column 700 or 710, whichever is less

Subtotal Enter at amount 17A. _____ 16A

Calculation 2 – Only if you transferred all or a part of the qualified expenditure to another person under an agreement described in subsection 127(13); otherwise, enter nil at amount 16B.

A Rate that the transferee used in determining its ITC for qualified expenditures under a subsection 127(13) agreement **720**	B Proceeds of disposition of the property if you dispose of it to an arm's length person; or, in any other case, enter the fair market value of the property at conversion or disposition **730**	C Amount, if any, already provided for in Calculation 1 (This allows for the situation where only part of the cost of a property is transferred under a subsection 127(13) agreement.) **740**	D Amount determined by the formula (A x B) – C	E ITC earned by the transferee for the qualified expenditures that were transferred **750**	F Amount from column D or E, whichever is less

Subtotal (total of column F) Enter at amount 17B. _____ 16B

Calculation 3

As a member of the partnership, you will report your share of the SR&ED ITC of the partnership after the SR&ED ITC has been reduced by the amount of the recapture. If this amount is a positive amount, you will report it on line 550 in Part 12. However, if the partnership does not have enough ITC otherwise available to offset the recapture, then the amount by which reductions to ITC exceed additions (the excess) will be determined and reported on line 760.

Corporate partner's share of the excess of SR&ED ITC **760** _____
Enter at amount 17C.

Part 17 – Total recapture of SR&ED investment tax credit

Recaptured ITC from calculation 1, amount 16A		17A
Recaptured ITC from calculation 2, amount 16B		17B
Recaptured ITC from calculation 3, line 760 in Part 16		17C
Total recapture of SR&ED investment tax credit (total of amounts 17A to 17C) Enter at amount 24A in Part 24.		17D

Pre-Production Mining

Part 18 – Account balances – ITC from pre-production mining expenditures

ITC at the end of the previous tax year				18A
Credit deemed as a remittance of co-op corporations	841			
Credit expired	845			
Subtotal (line 841 **plus** line 845)		▶		18B
ITC at the beginning of the tax year (amount 18A **minus** amount 18B)		850		
Credit transferred on an amalgamation or the wind-up of a subsidiary		860		
Total credit available (line 850 **plus** line 860)				18C
Amount of unused credit carried forward from previous years and applied to reduce Part I tax payable in the current year		885		
ITC closing balance from pre-production mining expenditures (amount 18C **minus** line 885)		890		

Apprenticeship Job Creation

Part 19 – Total current-year credit – ITC from apprenticeship job creation expenditures

If you are a related person as defined under subsection 251(2), has it been agreed in writing that you are the only employer who will be claiming the apprenticeship job creation tax credit for this tax year for each apprentice whose contract number (or social insurance number (SIN) or name) appears below? (If not, you cannot claim the tax credit.) . . . . . **611** Yes ☐ No ☐

For each apprentice in their first 24 months of the apprenticeship, enter the apprenticeship contract number registered with Canada, or a province or territory, under an apprenticeship program designed to certify or license individuals in the trade. For the province, the trade must be a Red Seal trade. If there is no contract number, enter the SIN or the name of the eligible apprentice.

	A Contract number (SIN or name of apprentice) **601**	B Name of eligible trade **602**	C Eligible salary and wages[11] **603**	D Column C x 10 % **604**	E Lesser of column D or $ 2,000 **605**
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2.					
3.					
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	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages[11] 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
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	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages[11] 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
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	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages[11] 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
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152					
153					
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	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages[11] 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
204					
205					
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T2 SCH 31 E (26)

	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages[11] 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
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	A Contract number (SIN or name of apprentice) 601	B Name of eligible trade 602	C Eligible salary and wages[11] 603	D Column C x 10 % 604	E Lesser of column D or $ 2,000 605
310					
311					
312					
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319					

Total current-year credit (total of column E) Enter on line 640 in Part 20. 580,560 19A

[11] Other than qualified expenditure incurred, and net of any other government or non-government assistance received or to be received. **Eligible salary and wages**, and **qualified expenditures** are defined under subsection 127(9).

Part 20 – Current-year credit and account balances – ITC from apprenticeship job creation expenditures

ITC at the end of the previous tax year				20A
Credit deemed as a remittance of co-op corporations	612			
Credit expired after 20 tax years	615			
Subtotal (line 612 **plus** line 615)				20B
ITC at the beginning of the tax year (amount 20A **minus** amount 20B)		625		
Credit transferred on an amalgamation or the wind-up of a subsidiary	630			
ITC from repayment of assistance	635			
Total current-year credit (amount 19A)	640	580,560		
Credit allocated from a partnership	655			
Subtotal (total of lines 630 to 655)		580,560	580,560	20C
Total credit available (line 625 **plus** amount 20C)			580,560	20D
Credit deducted from Part I tax	660	580,560		
Credit carried back to previous years (amount 21A)			20E	
Subtotal (line 660 **plus** amount 20E)		580,560	580,560	20F
ITC closing balance from apprenticeship job creation expenditures (amount 20D **minus** amount 20F)		690		

Part 21 – Request for carryback of credit from apprenticeship job creation expenditures

	Year	Month	Day			
1st previous tax year				Credit to be applied	931	
2nd previous tax year				Credit to be applied	932	
3rd previous tax year				Credit to be applied	933	

Total of lines 931 to 933 Enter at amount 20E. 21A

Child Care Spaces

Part 22 – Account balances – ITC from child care spaces expenditures

ITC at the end of the previous tax year				22A
Credit deemed as a remittance of co-op corporations	765			
Credit expired after 20 tax years	770			
Subtotal (line 765 **plus** line 770)		▶		22B
ITC at the beginning of the tax year (amount 22A **minus** amount 22B)		775		
Credit transferred on an amalgamation or the wind-up of a subsidiary	777			
Credit allocated from a partnership	782			
Subtotal (line 777 **plus** line 782)		▶		22C
Total credit available (line 775 **plus** amount 22C)				22D
Credit deducted from Part I tax		785		
ITC closing balance from child care spaces expenditures (amount 22D **minus** line 785)		790		

Summary of Investment Tax Credits

Part 23 – Clean economy ITCs

Clean hydrogen ITC (from Schedule 74)	140		
Clean technology ITC (from Schedule 75)	155		
Clean technology manufacturing ITC (from Schedule 76)	170		
Clean electricity ITC	185		
Carbon capture, utilization, and storage ITC (from Schedule 78)	200		
Clean economy ITCs (total of lines 140 to 200)			23A

Include the total on line 780 of the T2 return.

Part 24 – Total recapture of investment tax credit

Recaptured SR&ED ITC (amount 17D)		24A
Recaptured or recovered clean hydrogen ITC (from Schedule 74)		24B
Recaptured clean technology ITC (from Schedule 75)		24C
Recaptured clean technology manufacturing ITC (from Schedule 76)		24D
Recaptured or recovered clean electricity ITC		24E
Total recapture of investment tax credit (total of amounts 24A to 24E)		24F

Enter on line 602 of the T2 return.

Part 25 – Total ITC deducted from Part I tax

ITC from investments in qualified property deducted from Part I tax (line 260 in Part 5)		25A
ITC from SR&ED expenditures deducted from Part I tax (line 560 in Part 12)		25B
ITC from pre-production mining expenditures deducted from Part I tax (line 885 in Part 18)		25C
ITC from apprenticeship job creation expenditures deducted from Part I tax (line 660 in Part 20)	580,560	25D
ITC from child care space expenditures deducted from Part I tax (line 785 in Part 22)		25E
Total ITC deducted from Part I tax (total of amounts 25A to 25E)	580,560	25F

Enter on line 652 of the T2 return.

T2 SCH 31 E (26)

Summary of Investment Tax Credit Carryovers

Continuity of investment tax credit carryovers

CCA class number 97 Apprenticeship job creation ITC

Current year

Addition current year (A)	Applied current year (B)	Claimed as a refund (C)	Carried back (D)	ITC end of year (A-B-C-D)
580,560	580,560			

Prior years

Taxation year	ITC beginning of year (E)	Adjustments (F)	Applied current year (G)	ITC end of year (E-F-G)
2024-12-31				
2023-12-31				
2022-12-31				
2021-12-31				
2020-12-31				
2019-12-31				
2018-12-31				
2017-12-31				
2016-12-31				
2015-12-31				
2015-11-04				
2015-10-31				
2014-12-31				
2013-12-31				
2012-12-31				
2011-12-31				
2010-12-31				
2009-12-31				
2008-12-31				
2007-12-31				*
Total				

B+C+D+G **Total ITC utilized** 580,560

* The **ITC end of year** includes the amount of ITC expired from the 20th preceding year. Note that this credit expires at the end of the tax year and any expired credit will be posted to line 215, 515, 615, 770 or 845, as applicable, in Schedule 31 the following year.

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Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	2,712,979,227	
Capital stock (or members' contributions if incorporated without share capital)	103	2,934,000,000	
Retained earnings	104	9,815,227,074	
Contributed surplus	105	5,000,000	
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	18,253,367,596	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109		
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		33,720,573,897 ▶	33,720,573,897 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if

a) those lines applied to partnerships in the same manner that they apply to corporations, and

b) those amounts were computed without reference to amounts owing by the partnership

(i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or

(ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)		33,720,573,897	A
Deduct the following amounts:			
Deferred tax debit balance at the end of the year	121		
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122		
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123		
Deferred unrealized foreign exchange losses at the end of the year	124		
Subtotal (**add** lines 121 to 124)			B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	33,720,573,897	

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	4,972,192
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	4,972,192

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		33,720,573,897	C
Deduct: Investment allowance for the year (line 490)		4,972,192	D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	33,715,601,705	

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 33,715,601,705 x Taxable income earned in Canada / Taxable income **610** 525,677,432 / 525,677,432 = **Taxable capital employed in Canada** **690** 33,715,601,705

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . **701** _____

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . . **711** _____

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . . **712** _____

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . . **713** _____

Total deductions (**add** lines 711, 712, and 713) _____ ▶ _____ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter "0") . . . . . **790** _____

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690) . . . . . _____ F

Deduct: . . . . . 10,000,000 G

Excess (amount F **minus** amount G) (if negative, enter "0") _____ H

Calculation for purposes of the small business deduction (amount H x 0.225%) . . . . . _____ I

Enter this amount at line 415 of the T2 return.

Attached Schedule with Total

Part 2 – A loan or advance to another corporation (other than a financial institution)

Title Schedule 33/CT23 - Supplementary Schedule Line 402

Description	Operator (Note)	Amount
Prepaids (a/c 277180/277190)		3,627,303 00
Deposit -Bnft Provider (a/c 277290)	+	1,344,889 00
	Total	4,972,192 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – Reserves that have not been deducted in calculating income for the year under Part I

Title Part 1 – Reserves that have not been deducted in calculating income for the

Description	Operator (Note)	Amount
Schedule 13 Reserves Ending		2,712,979,227 00
	+	
	Total	2,712,979,227 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Part 1 – All loans and advances to the corporation

Title Part 1 – All loans and advances to the corporation

Description	Operator (Note)	Amount
LT Debt Payable within a year (FS)		1,144,000,000 00
Primary Debt (FS)	+	17,019,000,000 00
Banked Vacation (GL 362100)	+	14,205,602 00
Customer Deposits (GL 390000/391010/392000/392010)	+	76,161,994 00
	+	
	Total	18,253,367,596 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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Schedule 54

Low Rate Income Pool (LRIP) Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

On: 2025-12-31

- Use this schedule to calculate the balance of the low rate income pool (LRIP) at any time in the tax year if you are a corporation resident in Canada that is:
  - a corporation **other** than a Canadian-controlled private corporation (CCPC) or a deposit insurance corporation (DIC)
  - a corporation that elected under subsection 89(11) not to be a CCPC
  - a corporation that was a substantive CCPC at any time in the previous tax year starting after April 6, 2022
- When an eligible dividend was paid or there was a change in the LRIP balance in the tax year, file this schedule with your T2 Corporation Income Tax Return. Do not send your worksheets (pages 3 to 5) with your return, but keep them in case we ask to see them later.
- Unless otherwise stated, all legislative references are to the Income Tax Act.
- Subsection 89(1) defines the terms **eligible dividend, excessive eligible dividend designation, general rate income pool,** and **low rate income pool.**
- Subsection 129(4) defines the term **aggregate investment income** and subsection 248(1) defines the term **substantive CCPC**.

Did the corporation elect not to be a CCPC under subsection 89(11) ITA for the current year or a prior year or did it revoke this election in the current year*? . . . . . ☐ Yes ☒ No

Was the corporation a substantive CCPC at any time in its preceding taxation year? . . . . . ☐ Yes ☒ No

* If the corporation revoked its election in the current year when filing Form T2002, this election will still be valid for the current year, but will cease to apply as of the end of the year.

Eligibility for the various additions

Answer the following questions to determine the corporation's eligibility for the various additions:

Change in the type of corporation

1. Was the corporation a CCPC during its preceding taxation year? . . . . . ☐ Yes ☒ No
2. Corporations that ceased to be a CCPC or a DIC . . . . . ☐ Yes ☒ No
   If the answer to question 2 is yes, complete Part 4.

Amalgamation (first year of filing after amalgamation)

3. Corporations that were formed as a result of an amalgamation . . . . . ☐ Yes ☒ No
   If the answer to question 3 is yes, answer questions 4 and 5. If the answer is no, go to question 6.
4. Was one or several of the predecessor corporations a CCPC or a DIC during the taxation year that ended immediately before the amalgamation? . . . . . ☐ Yes ☐ No
   If the answer to question 4 is yes, complete Part 5.
5. Was one or several of the predecessor corporations neither a CCPC nor a DIC? . . . . . ☐ Yes ☐ No
   If the answer to question 5 is yes, complete Part 5.

Winding-up

6. Corporations that wound-up a subsidiary . . . . . ☐ Yes ☒ No
   If the answer to question 6 is yes, answer questions 7 and 8. If the answer is no, go to Part 1.
7. Was the subsidiary a CCPC or a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
   If the answer to question 7 is yes, complete Part 6.
8. Was the subsidiary neither a CCPC nor a DIC during its last taxation year? . . . . . ☐ Yes ☐ No
   If the answer to question 8 is yes, complete Part 6.

Part 1 – Low rate income pool (LRIP)

LRIP at the end of the immediately previous tax year				100	
Aggregate investment income for the previous tax year [1] (line 440 of the T2 return of the previous tax year)	140		x 80 % =	150	
Investment corporation deduction (line 620 of the T2 return of the previous tax year)			x 4 =	160	
Subtotal (**add** lines 100, 150, and 160)				190	

1 Enter an amount on line 140 **only** if:
- you **were not** a CCPC in the previous tax year because of an election under subsection 89(11)
- you **were** a substantive CCPC at any time in the previous tax year starting after April 6, 2022

Part 2 – LRIP and excessive eligible dividend designations during the tax year

- Fill out this part if you paid an eligible dividend in the tax year.
- If you need more space, attach additional sheets.

	1 Date[2] (yyyy/mm/dd) 200	2 Total dividends[3] receivable in the year before the date on line 200 that are deductible under section 112 210	3 Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC[4] 220	4 Subtotal (**add** lines 190, 210, and 220) 230	5 Total dividends[5] payable in the year before the date on line 200 240	6 Total of excessive eligible dividend designations made before the date on line 200 250
1.	2025-03-28					
2.	2025-06-27					
3.	2025-09-26					
4.	2025-12-30					

	7 LRIP as of the date on line 200 (line 230 **minus** the total of line 240 and line 250) 260	8 Total eligible dividends paid on the date on line 200 270	9 Excessive eligible dividend designation (lesser of lines 260 and 270) 280
1.		187,342,681	
2.		206,784,950	
3.		198,785,533	
4.		198,787,321	

Total excessive eligible dividend designations in the tax year (total of column 9) _____ A

Enter amount A at amount C of Schedule 55.

2 Enter in column 1 each date when:
- an eligible dividend was paid in the year
- an adjustment was made as a result of an amalgamation or the wind-up of a subsidiary or on ceasing to be a CCPC (by an election or otherwise)

3 Include taxable dividends from a corporation resident in Canada (other than eligible dividends).

4 Fill out Part 4 when the corporation ceases to be a CCPC or DIC. Fill out Part 5 for **each** predecessor involved in the amalgamation and Part 6 for **each** subsidiary involved in the wind-up. Add the adjustments calculated in parts 4 to 6 for the same date and enter the result in column 3 beside the appropriate date entered in column 1. Enter the total of column 3 on line 520 in Part 3.

5 Include taxable dividends other than eligible dividends, capital gains dividends within the meaning assigned by subsection 130.1(4) or 131(1), or dividends deductible under subsection 130.1(1).

Part 3 – LRIP closing balance

Amount from line 190 in Part 1 . . . . . _____ B

Dividends[6] receivable in the tax year that are deductible under section 112 (Amount on line 210 in the last row (last date) of the chart in Part 2) . . . . . _____

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends receivable in the year that are deductible under section 112 (hereinafter: "dividends other than eligible dividends receivable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends receivable other than eligible dividends receivable. . . . . _____

Total dividends[6] receivable in the tax year that are deductible under section 112 . . . . . **510** _____

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC[7] (Amount on line 220 in the last row (last date) of the chart in Part 2) . . . . . _____

Adjustments for amalgamations, wind-ups, or ceasing to be a CCPC[7] if no eligible dividend has been paid in the tax year . . . . . _____

Total adjustments for amalgamations, wind-ups, or on ceasing to be a CCPC[7] . . . . . **520** _____

Subtotal (line 510 **plus** line 520) _____ ▶ _____ C

Subtotal (amount B **plus** amount C) _____ D

Total dividends[8] payable in the tax year (Amount on line 240 in the last row (last date) of the chart in Part 2) . . . _____

80% of the aggregate investment income for the preceding taxation year (amount from line 150) . . . . . _____ aa

Portion of the taxable dividends that became payable in the preceding taxation year that has not reduced the LRIP in the preceding taxation year . . . . . _____ ab

Lesser of the amounts aa and ab . . . . . _____ ▶ _____

If an eligible dividend has been paid in the tax year, enter all dividends other than eligible dividends payable in the year (hereinafter: "dividends other that eligible dividends payable") on the date in the last row, or after (last date), from column 200 in Part 2. If no eligible dividend was paid in the tax year, enter all dividends paid other than eligible dividends paid. . . . . _____

Total dividends[8] payable in the tax year . . . . . **540** _____

Total excessive eligible dividend designations in the tax year (amount A in Part 2) . . . . . _____ E

Subtotal (line 540 **plus** amount E) _____ ▶ _____ F

LRIP at the end of the tax year (amount D **minus** amount F) (if negative, enter "0") . . . . . **590** _____

6 Include taxable dividends from a corporation resident in Canada (other than eligible dividends).

7 Fill out Part 4 when the corporation ceases to be a CCPC or DIC. Fill out Part 5 for **each** predecessor involved in the amalgamation and Part 6 for **each** subsidiary involved in the wind-up. Add the adjustments calculated in parts 4 to 6 for the same date and enter the result in column 3 beside the appropriate date entered in column 1 of Part 2. Enter the total of column 3 on line 520.

8 Include taxable dividends other than eligible dividends, capital gains dividends within the meaning assigned by subsection 130.1(4) or 131(1), or dividends deductible under subsection 130.1(1). For a non-CCPC with a tax year starting after April 6, 2022, include amounts paid in the previous tax year that did not reduce the LRIP or line 150 of the previous tax year, whichever is less.

Part 4 – Worksheet for adjustment when a corporation ceases to be a CCPC or DIC

Adjustment date . . . . . _____

- Fill out this part if the corporation is neither a CCPC nor a DIC in this tax year but was a CCPC or a DIC in the previous tax year.
- This adjustment to the LRIP can be made at any time in the tax year.
- Keep a copy of this calculation for your records in case we ask to see it later.

Cost amount to the corporation of all property immediately before the end of the previous tax year . . . . . _____ 1

The corporation's cash on hand immediately before the end of the previous tax year . . . . . _____ 2

Total of subsection 111(1) losses that would have been deductible in computing the corporation's taxable income for the previous tax year if the corporation had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for the previous tax year:

Non-capital losses	_____ 3		
Net capital losses	_____ 4		
Farm losses	_____ 5		
Restricted farm losses	_____ 6		
Limited partnership losses	_____ 7		
Subtotal (**add** amounts 3 to 7)	_____ ▶	_____ 8	

Total of all amounts deducted under subsection 111(1) in computing the corporation's taxable income for the previous tax year:

Non-capital losses	_____ 9		
Net capital losses	_____ 10		
Farm losses	_____ 11		
Restricted farm losses	_____ 12		
Limited partnership losses	_____ 13		
Subtotal (**add** amounts 9 to 13)	_____ ▶	_____ 14	

Unused and unexpired losses at the end of the corporation's previous tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . . _____ ▶ _____ 15

Subtotal (**add** amounts 1, 2, and 15) _____ 16

All of the corporation's debts and other obligations to pay that were outstanding immediately before the end of its previous tax year . . . . . _____ 17

Paid up capital of all the corporation's issued and outstanding shares of capital stock immediately before the end of its previous tax year . . . . . _____ 18

All of the corporation's reserves deducted in its previous tax year . . . . . _____ 19

Is the corporation a private corporation? . . . . . ☐ Yes ☒ No

The corporation's capital dividend account immediately before the end of its previous tax year if the corporation is **not** a private corporation in the current tax year . . . . . _____ 20

The corporation's general rate income pool (GRIP) at the end of its previous tax year . . . . . _____ 21

Eligible dividends paid in the previous tax year . . . . . _____ 22

Excessive eligible dividend designations made in the previous tax year . . . . . _____ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . . _____ ▶ _____ 24

Subtotal (amount 21 **minus** amount 24) _____ ▶ _____ 25

Subtotal (**add** amounts 17, 18, 19, 20, and 25) _____ ▶ _____ 26

Adjustment for a corporation that ceases to be a CCPC or DIC (amount 16 **minus** amount 26) (if negative, enter "0") . . . . . _____ 27

Part 5 – Worksheet for adjustment when a corporation is formed as a result of an amalgamation

nb. 1

Adjustment date . . . . . _____

- Fill out this part if the corporation was formed as a result of an amalgamation or merger of two or more corporations, one or more of which is a taxable Canadian corporation. Fill out a separate worksheet for **each** predecessor.
- This adjustment to the LRIP can be made at any time in the tax year.
- The last tax year was its tax year that ended immediately before the amalgamation.
- Keep a copy of this calculation for your records in case we ask to see it later.

For a predecessor corporation that was a CCPC or a DIC in its tax year that ended immediately before the amalgamation

Cost amount to the predecessor of all property immediately before the end of its last tax year . . . . . _____ 1

The predecessor's cash on hand immediately before the end of its last tax year . . . . . _____ 2

Total of subsection 111(1) losses that would have been deductible in computing the predecessor's taxable income for its last tax year if the predecessor had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for its last tax year:

Non-capital losses	_____ 3		
Net capital losses	_____ 4		
Farm losses	_____ 5		
Restricted farm losses	_____ 6		
Limited partnership losses	_____ 7		
Subtotal (**add** amounts 3 to 7)	_____ ▶	_____	8

Total of all amounts deducted under subsection 111(1) in computing the predecessor's taxable income for its last tax year:

Non-capital losses	_____ 9		
Net capital losses	_____ 10		
Farm losses	_____ 11		
Restricted farm losses	_____ 12		
Limited partnership losses	_____ 13		
Subtotal (**add** amounts 9 to 13)	_____ ▶	_____	14

Unused and unexpired losses at the end of the predecessor's last tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . . _____ ▶ _____ 15

Subtotal (**add** amounts 1, 2, and 15) _____ 16

All of the predecessor's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . . _____ 17

Paid up capital of all the predecessor's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . . _____ 18

All of the predecessor's reserves deducted in its last tax year . . . . . _____ 19

The predecessor's capital dividend account immediately before the end of its last tax year if the corporation is **not** a private corporation in its first tax year . . . . . _____ 20

The predecessor's general rate income pool (GRIP) at the end of its last tax year . . . . . _____ 21

Eligible dividends paid in its last tax year . . _____ 22

Excessive eligible dividend designations made in its last tax year . . . . . _____ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . . _____ ▶ _____ 24

Subtotal (amount 21 **minus** amount 24) _____ ▶ _____ 25

Subtotal (**add** amounts 17, 18, 19, 20, and 25) _____ ▶ _____ 26

Adjustment for a predecessor corporation that was a CCPC or a DIC in its last tax year (amount 16 **minus** amount 26) (if negative, enter "0") . . . . . _____ 27

For a predecessor corporation that was neither a CCPC nor a DIC in its tax year that ended immediately before the amalgamation

LRIP at the end of its last tax year . . . . . _____ 28

Adjustment for a predecessor corporation involved in an amalgamation (amount 27 **plus** amount 28) . . . . . _____ 29

Calculate amount 29 for **each** predecessor.

Part 6 – Worksheet for adjustment when a corporation has wound-up a subsidiary

nb. 1

Adjustment date . . . . . _____

- Fill out this part if the corporation is the parent corporation (parent) that is neither a CCPC nor a DIC in a tax year and has, in the year, received all or substantially all of the assets on dissolution or wind-up of a subsidiary. Fill out a separate worksheet for **each** subsidiary involved in the wind-up.
- This adjustment to the parent's LRIP can be made at any time in the tax year that is at or after the end of the subsidiary's last tax year.
- The last tax year for the subsidiary was its tax year during which its assets were distributed to the parent corporation on the wind-up.
- Keep a copy of this calculation for your records in case we ask to see it later.

For a subsidiary that was a CCPC or a DIC in its last tax year

Cost amount to the subsidiary of all property immediately before the end of its last tax year . . . . . _____ 1

The subsidiary's cash on hand immediately before the end of its last tax year . . . . . _____ 2

Total of subsection 111(1) losses that would have been deductible in computing the subsidiary's taxable income for its last tax year if the subsidiary had had unlimited income from each business carried on and each property held and had realized an unlimited amount of capital gains for its last tax year:

Non-capital losses	_____ 3		
Net capital losses	_____ 4		
Farm losses	_____ 5		
Restricted farm losses	_____ 6		
Limited partnership losses	_____ 7		
Subtotal (**add** amounts 3 to 7)	_____ ▶	_____	8

Total of all amounts deducted under subsection 111(1) in computing the subsidiary's taxable income for the last tax year:

Non-capital losses	_____ 9		
Net capital losses	_____ 10		
Farm losses	_____ 11		
Restricted farm losses	_____ 12		
Limited partnership losses	_____ 13		
Subtotal (**add** amounts 9 to 13)	_____ ▶	_____	14

Unused and unexpired losses at the end of the subsidiary's last tax year (amount 8 **minus** amount 14) (if negative, enter "0") . . . . . _____ ▶ _____ 15

Subtotal (**add** amounts 1, 2, and 15) _____ 16

All of the subsidiary's debts and other obligations to pay that were outstanding immediately before the end of its last tax year . . . . . _____ 17

Paid up capital of all the subsidiary's issued and outstanding shares of capital stock immediately before the end of its last tax year . . . . . _____ 18

All of the subsidiary's reserves deducted in its last tax year . . . . . _____ 19

The subsidiary's capital dividend account immediately before the end of its last tax year if the parent is **not** a private corporation in the tax year . . . . . _____ 20

The subsidiary's general rate income pool (GRIP) at the end of its last tax year . . . . . _____ 21

Eligible dividends paid in its last tax year . . _____ 22

Excessive eligible dividend designations made in its last tax year . . . . . _____ 23

Subtotal (amount 22 **minus** amount 23) (if negative, enter "0") . . . . . _____ ▶ _____ 24

Subtotal (amount 21 **minus** amount 24) _____ ▶ _____ 25

Subtotal (**add** amounts 17, 18, 19, 20, and 25) _____ ▶ _____ 26

Adjustment for a subsidiary that was a CCPC or a DIC in its last tax year (amount 16 **minus** amount 26) (if negative, enter "0") . . _____ 27

For a subsidiary that was neither a CCPC nor a DIC in its last tax year

LRIP at the end of its last tax year . . . . . _____ 28

Adjustment for a subsidiary involved in a wind-up (amount 27 **plus** amount 28**)** . . . . . _____ 29

Calculate amount 29 for **each** subsidiary.

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Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3			
Total taxable dividends paid in the tax year	100		
Total eligible dividends paid in the tax year	150		
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")	160		
Excessive eligible dividend designation (line 150 **minus** line 160)			A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	180		
Subtotal (amount A **minus** line 180)			B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)	190		

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3			
Taxable dividends paid in the tax year **included** in Schedule 3		791,700,485	
Total taxable dividends paid in the tax year	200	791,700,485	
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)			C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *	280		
Subtotal (amount C **minus** line 280)			D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)	290		

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

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Schedule 500

Ontario Corporation Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Use this schedule if your corporation had a **permanent establishment** (as defined in section 400 of the federal Income Tax Regulations) in Ontario at any time in the tax year and had Ontario taxable income in the tax year.
- Legislative references are to the federal Income Tax Act and Income Tax Regulations.
- This schedule is a worksheet only and is not required to be filed with your T2 Corporation Income Tax Return.

Part 1 – Ontario basic income tax

Ontario taxable income **(Note 1)** 525,677,432 1A

Ontario basic rate of tax for the year . . . . . **11.5** % 1B

Ontario basic income tax (amount 1A **multiplied** by amount 1B) **(Note 2)** 60,452,905 1C

Note 1: If your corporation had a permanent establishment only in Ontario, enter the amount from line 360, from page 3 of the T2 return. Otherwise, enter the taxable income allocated to Ontario from column F in Part 1 of Schedule 5.

Note 2: If your corporation had a permanent establishment in more than one jurisdiction or is claiming an Ontario tax credit in addition to Ontario basic income tax, Ontario corporate minimum tax, or Ontario special additional tax on life insurance corporations payable, enter amount 1C on line 270 of Schedule 5, Tax Calculation Supplementary – Corporations. Otherwise, enter it on line 760 of the T2 return.

Part 2 – Ontario small business deduction (OSBD)

Complete this part if your corporation claimed the federal small business deduction under subsection 125(1).

Line 400 of the T2 return 2A

Line 405 of the T2 return 2B

Line 410 of the T2 return 2C

Line 415 of the T2 return 2D

Business limit reduction for tax years starting before April 7, 2022

Amount 2C x Amount 2D = 2E
11,250

Business limit reduction for tax years starting after April 6, 2022

Amount 2C x Amount 2D = 2F
90,000

Amount 2E or amount 2F, whichever applies 2G

Line 515 of the T2 return 2H

Subtotal (amount 2C **minus** amount 2G **minus** amount 2H) ▶ 2I

Amount 2A, 2B or 2I whichever is the least . . . . . ▶ 2J

Ontario domestic factor (ODF): Taxable income for Ontario **(Note 3)** 525,677,432.00 / Taxable income for all provinces **(Note 4)** 525,677,432 = ... 1.00000 2K

Amount 2J **multiplied** by amount 2K 2L

Ontario taxable income (amount 1A) 525,677,432 2M

Ontario small business income (amount 2L or 2M, whichever is less) . . . . . ▶ 2N

Ontario small business deduction for the year

Amount 2N x 8.3 % = ... 2O

Enter Ontario small business deduction for the year (amount 2O) on line 402 of Schedule 5.

Note 3: Enter amount 1A.

Note 4: Includes the territories and the offshore jurisdictions for Nova Scotia and Newfoundland and Labrador.

Part 3 – Ontario adjusted small business income

Complete this part if your corporation was a Canadian-controlled private corporation throughout the tax year and is claiming the Ontario tax credit for manufacturing and processing or the Ontario credit union tax reduction.

Ontario adjusted small business income (amount 1A or 2J, whichever is the least) . . . . . _____ 3A

Enter amount 3A at amount 4B in Part 4 of this schedule or at amount 2E in Part 2 of Schedule 502, Ontario Tax Credit for Manufacturing and Processing, whichever applies.

Part 4 – Credit union tax reduction

Complete this part and Schedule 17, Credit Union Deductions, if the corporation was a credit union throughout the tax year.

Amount 2C of Schedule 17 . . . . . _____ 4A

Ontario adjusted small business income (amount 3A) . . . . . _____ 4B

Subtotal (amount 4A **minus** amount 4B) (if negative, enter "0") _____ ▶ _____ 4C

Amount 4C _____ x 8.3 % = ... _____ 4D

Ontario domestic factor (amount 2K) 1.00000 4E

Ontario credit union tax reduction (amount 4D **multiplied** by amount 4E) . . . . . _____ 4F

Enter amount 4F on line 410 of Schedule 5.

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Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	37,922,000,000
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	
Total assets (total of lines 112 to 116)		37,922,000,000
Total revenue of the corporation for the tax year **	142	8,823,254,777
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	
Total revenue (total of lines 142 to 146)		8,823,254,777

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	1,322,046,268	
Add (to the extent reflected in income/loss):					
Provision for current income taxes/cost of current income taxes	220	133,059,361			
Provision for deferred income taxes (debits)/cost of future income taxes	222	77,963,203			
Equity losses from corporations	224				
Financial statement loss from partnerships and joint ventures	226				
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230				
Other additions (see note below):					
Share of adjusted net income of partnerships and joint ventures **	228	73,369,393			
Total patronage dividends received, not already included in net income/loss	232				
281 Estimated depreciation on capitalized interest	282	11,981,462			
283 See attached	284	882,598			
Subtotal		297,256,017	▶	297,256,017	A
Deduct (to the extent reflected in income/loss):					
Provision for recovery of current income taxes/benefit of current income taxes	320				
Provision for deferred income taxes (credits)/benefit of future income taxes	322				
Equity income from corporations	324				
Financial statement income from partnerships and joint ventures	326	60,876,233			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330				
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332				
Gain on donation of listed security or ecological gift	340				
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342				
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344				
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346				
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348				
Other deductions (see note below):					
Share of adjusted net loss of partnerships and joint ventures **	328				
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334				
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336	104,436,929			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338				
381 MTM on swap	382	2,698,379			
383	384				
385	386				
387	388				
389	390				
Subtotal		168,011,541	▶	168,011,541	B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	1,451,290,744	

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515	1,451,290,744	
Deduct:			
CMT loss available (amount R from Part 7)			
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available			C
Net income subject to CMT calculation (if negative, enter "0")	520	1,451,290,744	

Amount from line 520	1,451,290,744	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	365	x 4 % =		1
Amount from line 520	1,451,290,744	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x 2.7 % =	39,184,850	2
			Subtotal (amount 1 **plus** amount 2)			39,184,850	3

Gross CMT: amount on line 3 above x OAF **	540	39,184,850	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		39,184,850	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		60,452,905	
Net CMT payable (if negative, enter "0")			E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** =

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		242,529,756 G		
Deduct:				
CMT credit expired *	600			
CMT credit carryforward at the beginning of the current tax year * (see note below)		242,529,756 ▶	620	242,529,756
Add:				
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650	
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				242,529,756 H
Deduct:				
CMT credit deducted in the current tax year (amount P from Part 5)				21,268,055 I
Subtotal (amount H **minus** amount I)				221,261,701 J
Add:				
Net CMT payable (amount E from Part 3)				
SAT payable (amount O from Part 6 of Schedule 512)				
Subtotal		▶		K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	221,261,701 L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)			242,529,756 M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		60,452,905 1	
For a corporation that is not a life insurance corporation:			
CMT after foreign tax credit deduction (amount D from Part 3)	39,184,850 2		
For a life insurance corporation:			
Gross CMT (line 540 from Part 3)	3		
Gross SAT (line 460 from Part 6 of Schedule 512)	4		
The **greater** of amounts 3 and 4	5		
Deduct: line 2 or line 5, whichever applies:		39,184,850 6	
Subtotal (if negative, enter "0")		21,268,055 ▶	21,268,055 N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)		60,452,905	
Deduct:			
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)		933,000	
Subtotal (if negative, enter "0")		59,519,905 ▶	59,519,905 O
CMT credit deducted in the current tax year (least of amounts M, N, and O)			21,268,055 P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . . _____ Q

Deduct:

CMT loss expired * . . . . . 700 _____

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . . _____ ▶ 720 _____

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) . . . . . 750 _____

CMT loss available (line 720 **plus** line 750) . . . . . _____ R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . . . _____

Subtotal (if negative, enter "0") _____ S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) . . . . . 760 _____

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . . 770 _____ T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:

- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Attached Schedule with Total

Other additions – Amount

Title Other additions – Amount

Description	Operator (Note)	Amount
Tax on OCI		882,598 00
	+	
	Total	882,598 00

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return.*

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	Hydro One Limited			
2	Hydro One Inc.			
3	2486267 Ontario Inc.			
4	2486268 Ontario Inc.			
5	Hydro One Remote Communites Inc.			
6	Acronym Solutions Inc.			
7	Municipal Billing Services Inc.			
8	Hydro One Lake Erie Link Management Inc.			
9	Hydro One Indigenous Partnerships Inc.			
10	Norfolk Energy Inc.			
11	Norfolk Power Distribution Inc.			
12	Haldimand County Energy Inc.			
13	Haldimand County Hydro Inc.			
14	Woodstock Hydro Services Inc.			
15	Hydro One Sault Ste. Marie Holdings Inc.			
16	Hydro One Sault Ste. Marie Inc.			
17	Hydro One Sault Ste. Marie Holding Corp.			
18	1228185 Ontario Inc.			
19	1937680 Ontario Inc.			
20	1937681 Ontario Inc.			
21	2587264 Ontario Inc.			
22	Hydro One Holdings Limited			
23	2587265 Ontario Inc.			
24	Orillia Power Distribution Corporation			
25	2835785 Ontario Inc.			
26	Aux Energy Inc.			
27	Hydro One Broadband Solutions Inc.			
28	1000575868 ONTARIO INC			

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
29	1000575870 ONTARIO INC.			
30	Chatham x Lakeshore GP Inc			
31	1000878753 Ontario Inc			
32	Nextbridge (Optionco) Inc.			
33	Upper Canada Transmission 2, Inc			
34	Olympus Holding Corp			
		Total	450	550

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

*** Rules for total assets**

- Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
- Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

**** Rules for total revenue**

- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
- If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
- Include the associated corporation's share of the total revenue of partnerships and joint ventures.
- If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 550

ONTARIO CO-OPERATIVE EDUCATION TAX CREDIT

Name of corporation	Business Number	Tax year-end Year Month Day
HYDRO ONE NETWORKS INC.		2025-12-31

- Use this schedule to claim an Ontario co-operative education tax credit (CETC) under section 88 of the *Taxation Act, 2007* (Ontario).
- The CETC is a refundable tax credit that is equal to an eligible percentage (10% to 30%) of the eligible expenditures incurred by a corporation for a qualifying work placement. The maximum credit amount is $1,000 for each qualifying work placement ending before March 27, 2009, and $3,000 for each qualifying work placement beginning after March 26, 2009. For a qualifying work placement that straddles March 26, 2009, the maximum credit amount is prorated.
- Eligible expenditures are salaries and wages (including taxable benefits) paid or payable to a student in a qualifying work placement, or fees paid or payable to an employment agency for services performed by the student in a qualifying work placement. These expenditures must be paid on account of employment or services, as applicable, at a permanent establishment of the corporation in Ontario. Expenditures for a work placement (WP) are not eligible expenditures if they are greater than the amounts that would be paid to an arm's length employee.
- A WP must meet all of the following conditions to be a qualifying work placement:
  - the student performs employment duties for a corporation under a qualifying co-operative education program (QCEP);
  - the WP has been developed or approved by an eligible educational institution as a suitable learning situation;
  - the terms of the WP require the student to engage in productive work;
  - the WP is for a period of at least 10 consecutive weeks or, in the case of an internship program, not less than 8 consecutive months and not more than 16 consecutive months;
  - the student is paid for the work performed in the WP;
  - the corporation is required to supervise and evaluate the job performance of the student in the WP;
  - the institution monitors the student's performance in the WP; and
  - the institution has certified the WP as a qualifying work placement.
- Make sure you keep a copy of the letter of certification from the Ontario eligible educational institution containing the name of the student, the employer, the institution, the term of the WP, and the name/discipline of the QCEP to support the claim. Do not submit the letter of certification with the *T2 Corporation Income Tax Return*.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Corporate information

110 Name of person to contact for more information: Selma Yam

120 Telephone number including area code:

Is the claim filed for a CETC earned through a partnership?* . . . . . **150** 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 150, what is the name of the partnership? . . . . . **160** _____

Enter the percentage of the partnership's CETC allocated to the corporation . . . . . **170** _____ %

* When a corporate member of a partnership is claiming an amount for eligible expenditures incurred by a partnership, complete a Schedule 550 for the partnership as if the partnership were a corporation. Each corporate partner, other than a limited partner, should file a separate Schedule 550 to claim the partner's share of the partnership's CETC. The allocated amounts can not exceed the amount of the partnership's CETC.

Part 2 – Eligibility

1. Did the corporation have a permanent establishment in Ontario in the tax year? . . . . . **200** 1 Yes ☒ 2 No ☐
2. Was the corporation exempt from tax under Part III of the *Taxation Act*, 2007 (Ontario)? . . . . . **210** 1 Yes ☐ 2 No ☒

If you answered **no** to question 1 or **yes** to question 2, then the corporation is **not eligible** for the CETC.

Part 3 – Eligible percentage for determining the eligible amount

Corporation's salaries and wages paid in the previous tax year * **300** 1,306,882,732

For eligible expenditures incurred before March 27, 2009:

- If line 300 is $400,000 or less, enter 15% on line 310.
- If line 300 is $600,000 or more, enter 10% on line 310.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 310 using the following formula:

$$\text{Eligible percentage} = 15\,\% - \left[5\,\% \times \frac{(\text{amount on line 300} \ \textbf{minus}\ \$\ 400{,}000)}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . **310** 10.000 %

For eligible expenditures incurred after March 26, 2009:

- If line 300 is $400,000 or less, enter 30% on line 312.
- If line 300 is $600,000 or more, enter 25% on line 312.
- If line 300 is more than $400,000 and less than $600,000, enter the percentage on line 312 using the following formula:

$$\text{Eligible percentage} = 30\,\% - \left[5\,\% \times \frac{(\text{amount on line 300} \ \textbf{minus}\ \$\ 400{,}000)}{\$\ 200{,}000} \right]$$

Eligible percentage for determining the eligible amount . . . . . **312** 25.000 %

* If this is the first tax year of an amalgamated corporation and subsection 88(9) of the *Taxation Act, 2007* (Ontario) applies, enter the salaries and wages paid in the previous tax year by the predecessor corporations.

Part 4 – Calculation of the Ontario co-operative education tax credit

Complete a separate entry for each student for each qualifying work placement that ended in the corporation's tax year. If a qualifying work placement would otherwise exceed four consecutive months, divide the WP into periods of four consecutive months and enter each full period of four consecutive months as a separate WP. If the WP does not divide equally into four-month periods and if the period that is less than 4 months is 10 or more consecutive weeks, then enter that period as a separate WP. If that period is less than 10 consecutive weeks, then include it with the WP for the last period of 4 consecutive months. Consecutive WPs with two or more associated corporations are deemed to be with only one corporation, as designated by the corporations.

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	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
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	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
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	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
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	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
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	A Name of university, college, or other eligible educational institution 400	B Name of qualifying co-operative education program 405
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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	C Name of student 410	D Start date of WP (see note 1 below) 430	E End date of WP (see note 2 below) 435
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Note 1: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the start date for the separate WP.

Note 2: When the WP has been divided into separate periods because it exceeds four consecutive months, enter the end date for the separate WP.

Part 4 – Calculation of the Ontario co-operative education tax credit (continued)

	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
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	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
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	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
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	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
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	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
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	F1 Eligible expenditures before March 27, 2009 (see note 1 below) 450	Eligible percentage before March 27, 2009 (from line 310 in Part 3)	F2 Eligible expenditures after March 26, 2009 (see note 1 below) 452	Eligible percentage after March 26, 2009 (from line 310a in Part 3)	X Number of consecutive weeks of the WP completed by the student before March 27, 2009 (see note 3 below)	Y Total number of consecutive weeks of the student's WP (see note 3 below)
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	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
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	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
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	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
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	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
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	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
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	G Eligible amount (eligible expenditures **multiplied** by eligible percentage) (see note 2 below) 460	H Maximum CETC per WP (see note 3 below) 462	I CETC on eligible expenditures (column G or H, whichever is less) 470	J CETC on repayment of government assistance (see note 4 below) 480	K CETC for each WP (column I or column J) 490
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Ontario co-operative education tax credit (total of amounts in column K) **500** 933,000 **L**

or, if the corporation answered **yes** at line 150 in Part 1, determine the partner's share of amount L:

Amount L _____ x percentage on line 170 in Part 1 _____ % = ... _____ **M**

Enter amount L or M, whichever applies, on line 452 of Schedule 5, *Tax Calculation Supplementary – Corporations*. If you are filing more than one Schedule 550, add the amounts from line L or M, whichever applies, on all the schedules and enter the total amount on line 452 of Schedule 5.

Note 1: Reduce eligible expenditures by all government assistance, as defined under subsection 88(21) of the *Taxation Act, 2007* (Ontario), that the corporation has received, is entitled to receive, or may reasonably expect to receive, for the eligible expenditures, on or before the filing due date of the *T2 Corporation Income Tax Return* for the tax year.

Note 2: Calculate the eligible amount (Column G) using the following formula:

Column G = (column F1 x percentage on line 310) + (column F2 x percentage on line 312)

Note 3: If the WP ends before March 27, 2009, the maximum credit amount for the WP is $1,000.
If the WP begins after March 26, 2009, the maximum credit amount for the WP is $3,000.
If the WP begins before March 27, 2009, and ends after March 26, 2009, calculate the maximum credit amount using the following formula:

($1,000 x X/Y) + [$3,000 x (Y – X)/Y]

where "X" is the number of consecutive weeks of the WP completed by the student before March 27, 2009, and "Y" is the total number of consecutive weeks of the student's WP.

Note 4: When claiming a CETC for repayment of government assistance, complete a **separate entry** for each repayment and complete columns A to E and J and K with the details for the previous year WP in which the government assistance was received.
Include the amount of government assistance repaid in the tax year multiplied by the eligible percentage for the tax year in which the government assistance was received, to the extent that the government assistance reduced the CETC in that tax year.

Corporate Taxpayer Summary

Corporate information

Corporation's name . . . . . HYDRO ONE NETWORKS INC.

Taxation Year . . . . . 2025-01-01 to 2025-12-31

Jurisdiction . . . . . Ontario

BC	AB	SK	MB	ON	QC	NB	NS	NO	PE	NL	XO	YT	NT	NU	OC
☐	☐	☐	☐	X	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐	☐

Corporation is associated . . . . . Y

Corporation is related . . . . . Y

Number of associated corporations . . 34

Type of corporation . . . . . Corporation Controlled by a Public Corporation

Total amount due (refund) federal and provincial* . . . . . -27,654,234

* The amounts displayed on lines "Total amount due (refund) federal and provincial" are all listed in the help. Press F1 to consult the context-sensitive help.

Summary of federal information

Net income		613,168,945
Taxable income		525,677,432
Donations		1,679,294
Calculation of income from an active business carried on in Canada		610,621,468
Dividends paid		791,700,485
Dividends paid – Regular		
Dividends paid – Eligible	791,700,485	
Balance of the low rate income pool at the end of the previous year		
Balance of the low rate income pool at the end of the year		
Balance of the general rate income pool at the end of the previous year		
Balance of the general rate income pool at the end of the year		
Part I tax (base amount)		199,757,424

Credits against Part I tax		Summary of tax		Refunds/credits	
Small business deduction		Part I	78,271,055	ITC refund	
M&P deductions		Part IV		Dividends refund:	
Foreign tax credit		Part III.1		– Eligible dividends	
Investment tax credits	580,560	Other*		– Non-eligible dividends	
Abatement/Other*	120,905,809	Provincial or territorial tax	38,251,850	Instalments	144,177,139
				Other*	
				Balance due/refund (–)	-27,654,234

* The amounts displayed on lines "Other" are all listed in the Help. Press F1 to consult the context-sensitive help.

Summary of federal carryforward/carryback information

Carryforward balances

Financial statement reserve	2,789,141,221
Other reserves	76,161,994

Summary of provincial information – provincial income tax payable

	Ontario	Québec (CO-17)	Alberta (AT1)
Net income	613,168,945		
Taxable income	525,677,432		
% Allocation	100.00		
Attributed taxable income	525,677,432		
Tax payable before deduction*	60,452,905		
Deductions and credits	21,268,055		
Net tax payable	39,184,850		
Attributed taxable capital	N/A		N/A
Capital tax payable**	N/A		N/A
Total tax payable***	39,184,850		
Instalments and refundable credits	933,000		
Balance due/Refund (-)	38,251,850		
Logging Operations Return (COZ-1179)			
Logging tax payable	N/A		N/A

* For Québec, this includes special taxes.

** For Québec, this includes compensation tax and registration fee.

*** For Ontario, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations. The Balance due/Refund is included in the federal Balance due/refund.

Summary of provincial carryforward amounts

Other carryforward amounts

Ontario

Corporate minimum tax credit that can be carried forward over 20 years – Schedule 510 221,261,701

Summary – taxable capital

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
HYDRO ONE NETWORKS INC.			33,715,601,705	33,715,601,705
Hydro One Limited				
Hydro One Inc.				
2486267 Ontario Inc.				
2486268 Ontario Inc.				
Hydro One Remote Communites Inc.				
Acronym Solutions Inc.				
Municipal Billing Services Inc.				
Hydro One Lake Erie Link Management Inc.				
Hydro One Indigenous Partnerships Inc.				
Norfolk Energy Inc.				
Norfolk Power Distribution Inc.				
Haldimand County Energy Inc.				
Haldimand County Hydro Inc.				
Woodstock Hydro Services Inc.				
Hydro One Sault Ste. Marie Holdings Inc.				
Hydro One Sault Ste. Marie Inc.				
Hydro One Sault Ste. Marie Holding Corp.				
1228185 Ontario Inc.				
1937680 Ontario Inc.				

Federal

Corporate name	Taxable capital used to calculate the business limit reduction (T2, line 415)	Taxable capital used to calculate the SR&ED expenditure limit for a CCPC (Schedules 31 and 49)	Taxable capital used to calculate line 233 of the T2 return	Taxable capital used to calculate line 234 of the T2 return
1937681 Ontario Inc.				
2587264 Ontario Inc.				
Hydro One Holdings Limited				
2587265 Ontario Inc.				
Orillia Power Distribution Corporation				
2835785 Ontario Inc.				
Aux Energy Inc.				
Hydro One Broadband Solutions Inc.				
1000575868 ONTARIO INC				
1000575870 ONTARIO INC.				
Chatham x Lakeshore GP Inc				
1000878753 Ontario Inc				
Nextbridge (Optionco) Inc.				
Upper Canada Transmission 2, Inc				
Olympus Holding Corp				
Total			33,715,601,705	33,715,601,705

Québec

Corporate name	Paid-up capital used to calculate the Québec business limit reduction (CO-771) and to calculate the additional deduction for transportation costs of remote manufacturing SMEs (CO-156.TR)	Paid-up capital used to calculate the tax credit for investment (CO-1029.8.36.IN) and to determine the applicability of Forms CO-1029.8.33.CS and CO-1029.8.33.TE	Paid-up capital used to calculate the $1 million deduction (CO-1137.A and CO-1137.E)
Total			

Ontario

Corporate name	Specified capital used to calculate the expenditure limit – Ontario innovation tax credit (Schedule 566)
Total	

Alberta

Corporate name	Taxable capital used to calculate the Alberta innovation employment grant (Schedule A29)
Total	

Other provinces

Corporate name	Capital used to calculate the Newfoundland and Labrador capital deduction on financial institutions (Schedule 306)	Capital used to calculate the Nova Scotia basic capital deduction on financial institutions (Schedule 353)
Total		

Five-Year Comparative Summary

Federal information (T2)

	Current year	1st prior year	2nd prior year	3rd prior year	4th prior year
Taxation year end	**2025-12-31**	**2024-12-31**	**2023-12-31**	**2022-12-31**	**2021-12-31**
Net income	613,168,945	424,415,696	213,281,496	399,284,555	286,911,092
Taxable income	525,677,432	20,329,990	18,819,187	8,211,968	37,971,426
Active business income	610,621,468	423,929,119	211,894,520	380,633,963	278,519,922
Dividends paid	791,700,485	752,839,847	692,299,693	652,551,962	619,906,552
Dividends paid – Regular					
Dividends paid – Eligible	791,700,485	752,839,847	692,299,693	652,551,962	619,906,552
LRIP – end of the previous year					
LRIP – end of the year					
GRIP – end of the previous year					
GRIP – end of the year					
Donations	1,679,294	3,166,415	1,609,116	1,779,428	1,408,314
Balance due/refund (-)	-27,654,234	-204,287	-48,944	-2,120,348	-2,886,263
Line 996 – Amended tax return	☐	X	X	☐	☐

Loss carrybacks requested in prior years to reduce taxable income

Taxation year end	**2025-12-31**	**2024-12-31**	**2023-12-31**	**2022-12-31**	**2021-12-31**
Taxable income before loss carrybacks	N/A	N/A	18,819,187	8,211,968	37,971,426
Non-capital losses	N/A	N/A			
Net capital losses (50%)	N/A	N/A			
Restricted farm losses	N/A	N/A			
Farm losses	N/A	N/A			
Listed personal property losses (50%)	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted taxable income after loss carrybacks	N/A	N/A	18,819,187	8,211,968	37,971,426

Losses in the current year carried back to previous years to reduce taxable income (according to Schedule 4)

Taxation year end	**2025-12-31**	**2024-12-31**	**2023-12-31**	**2022-12-31**	**2021-12-31**
Adjusted taxable income before current year loss carrybacks*	N/A	20,329,990	18,819,187	8,211,968	N/A
Non-capital losses	N/A				N/A
Net capital losses (50%)	N/A				N/A
Restricted farm losses	N/A				N/A
Farm losses	N/A				N/A
Listed personal property losses (50%)	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted taxable income after loss carrybacks	N/A	20,329,990	18,819,187	8,211,968	N/A

* The adjusted taxable income before current year loss carryback takes into account loss carrybacks that were made in prior taxation years.

Loss carrybacks requested in prior years to reduce taxable dividends subject to Part IV tax

Taxation year end	2025-12-31	2024-12-31	2023-12-31	2022-12-31	2021-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before loss carrybacks	N/A	N/A			
Non-capital losses	N/A	N/A			
Farm losses	N/A	N/A			
Total loss carried back to prior years	N/A	N/A			
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A	N/A			

Losses in the current year carried back to previous years to reduce taxable dividends subject to Part IV tax (according to Schedule 4)

Taxation year end	2025-12-31	2024-12-31	2023-12-31	2022-12-31	2021-12-31
Adjusted Part IV tax multiplied by the multiplication factor**, before current-year loss carrybacks***	N/A				N/A
Non-capital losses	N/A				N/A
Farm losses	N/A				N/A
Total current year losses carried back to prior years	N/A				N/A
Adjusted Part IV tax multiplied by the multiplication factor**, after loss carrybacks	N/A				N/A

** The multiplication factor is 3 for dividends received before January 1, 2016, and 100 / 38 1/3 for dividends received after December 31, 2015.

*** The adjusted Part IV tax multiplied by the multiplication factor before current-year loss carrybacks takes into account loss carrybacks that were made in prior taxation years. This amount is multiplied by the multiplication factor to help you determine the loss amount that must be used to reduce Part IV tax payable to zero.

Federal taxes

Taxation year end	2025-12-31	2024-12-31	2023-12-31	2022-12-31	2021-12-31
Part I	78,271,055	200	200	200	
Part IV					
Part III.1					
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensitive help.

Credits against Part I tax

Taxation year end	2025-12-31	2024-12-31	2023-12-31	2022-12-31	2021-12-31
Small business deduction					
M&P deductions					
Foreign tax credit					
Investment tax credit	580,560	3,049,298	2,822,678	1,231,595	5,695,714
Abatement/other*	120,905,809	4,675,898	4,328,413	1,888,753	8,733,428

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensitive help.

Refunds/credits

Taxation year end	2025-12-31	2024-12-31	2023-12-31	2022-12-31	2021-12-31
ITC refund		60,879			
Dividend refund					
– Eligible dividends					
– Non-eligible dividends					
Instalments	144,177,139	33,371,186	31,385,074	36,000,433	31,876,519
Other*					

* The amounts displayed on lines "Other" are all listed in the help. Press F1 to consult the context-sensitive help.

Ontario

Taxation year end	2025-12-31	2024-12-31	2023-12-31	2022-12-31	2021-12-31
Net income	613,168,945	424,415,696	213,281,496	399,284,555	286,911,092
Taxable income	525,677,432	20,329,990	18,819,187	8,211,968	37,971,426
% Allocation	100.00	100.00	100.00	100.00	100.00
Attributed taxable income	525,677,432	20,329,990	18,819,187	8,211,968	37,971,426
Surtax					
Income tax payable before deduction	60,452,905	2,337,949	2,164,207	944,376	4,366,714
Income tax deductions /credits	21,268,055	454,757	274,951	80,290	284,151
Net income tax payable	39,184,850	1,883,192	1,889,256	864,086	4,082,563
Taxable capital					
Capital tax payable					
Total tax payable*	39,184,850	34,214,186	32,047,422	34,512,340	29,648,008
Instalments and refundable credits	933,000	986,608	711,492	632,455	657,752
Balance due/refund**	38,251,850	33,227,578	31,335,930	33,879,885	28,990,256

* For taxation years ending before January 1, 2009, this includes the corporate minimum tax and the premium tax. For taxation years ending after December 31, 2008, this includes the corporate minimum tax, the Crown royalties' additional tax, the transitional tax debit, the recaptured research and development tax credit and the special additional tax debit on life insurance corporations.

** For taxation years ending after December 31, 2008, the Balance due/Refund is included in the federal Balance due/refund.

HYDRO ONE NETWORKS INC. 2025 TAXABLE INCOME – ALLOCATION BY SEGMENT

This attachment has been filed separately in MS Excel format.

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HOSSM LP INCOME TAX RETURN

Attachment 1: HOSSM 2025 Income Tax Return

Witness: Anthony Nava

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Agence du revenu du Canada / Canada Revenue Agency

T5013 Financial
Protected B when completed

Partnership Financial Return

Complete this financial return using the instructions in the T4068, Guide for the Partnership Information Return (T5013 Forms). You can file this return electronically without a web access code using the "File a return" service in My Business Account and to authorized representatives and employees through Represent a Client. To access My Business Account and Represent a Client, go to **canada.ca/cra-sign-in-services**.

Unless otherwise stated, all legislative references are to the Income Tax Act.

055 **For internal use only.**

Identification

Partnership account number

001 [redacted]

Partnership name

006 Hydro One Sault Ste. Marie LP
007

Partnership operating or trading name

008 Hydro One Sault Ste. Marie LP
009

Location of the partnership head office

Has this location changed since the last time you filed a partnership information return? . . . . . **010** ☐ Yes ☒ No

If you answered **Yes** to line 010, enter the address of the new location on lines 011 to 018.

011
012

City **015** Province, territory, or state **016**

Country **017** Postal or zip code **018**

Mailing address of the partnership
(if different from the head office address)

Has this address changed since the last time you filed a partnership information return? . . . . . **020** ☐ Yes ☒ No

If you answered **Yes** to line 020, enter the new mailing address on lines 021 to 028.

021 c/o
023
024

City **025** Province, territory, or state **026**

Country **027** Postal or zip code **028**

Location of the partnership's books and records
(if different from the head office address)

Has this location changed since the last time you filed a partnership information return? . . . . . **030** ☐ Yes ☒ No

If you answered **Yes** to line 030, enter the address of the new location on lines 031 to 038.

031
032

City **035** Province, territory, or state **036**

Country **037** Postal or zip code **038**

Is this an amended return? . . . . . **040** ☐ Yes ☒ No

Fiscal period to which this information return applies

060 Fiscal period start — Year Month Day: From 2025-01-01

061 Fiscal period-end [1] — Year Month Day: To 2025-12-31

[1] If you answered **Yes** to question 078 below, enter the date when the partnership ceased to exist.

The end members of this partnership are
(tick the applicable boxes)

062
01 ☐ Individuals (including trusts)
02 ☒ Corporations

Is this the first year of filing? . . . . . **070** ☐ Yes ☒ No

If you answered **Yes** to line 070, enter the date the partnership was created . . . . . **071** Year Month Day

Number of T5013 slips **073** 2

Is this the partnership's final information return up to dissolution? . . . . . **078** ☐ Yes ☒ No

If an election was made under section 261 by one or more partners, enter the functional currency code used for this return **079**

Was the partnership a Canadian partnership throughout the fiscal period? . . . . . **082** ☒ Yes ☐ No

Type of partnership at the end of the fiscal period

086

Non tax shelter	Tax shelter
☐ 01 General partnership	☐ 11 General partnership
☒ 02 Limited partnership	☐ 12 Limited partnership
☐ 03 Limited liability partnership	☐ 13 Co-ownership
☐ 08 Investment club	☐ 19 Other (specify below)

If the partnership is a tax shelter (TS), enter the TS identification number **087**

Industry code (NAICS): 221121

Required documents to attach to this T5013 FIN, Partnership Financial Return

- Form T5013 SUM, Summary of Partnership Income
- A copy of each T5013, Statement of Partnership Income slip issued to partners and nominees or agents
- T5013 SCH 1, Net Income (Loss) for Income Tax Purposes[2]

  [2] If you are an inactive partnership, see line 280 in Guide T4068 for more information.
- T5013 SCH 50, Partner's Ownership and Account Activity

The General Index of Financial Information (GIFI) schedules

- T5013 SCH 100, Balance Sheet Information
- T5013 SCH 125, Income Statement Information
- T5013 SCH 140, Summary Statement (located at the bottom of page 2 of T5013 SCH 125 and used when more than one T5013 SCH 125 is filed)
- T5013 SCH 141, General Index of Financial Information (GIFI) – Additional Information (not required for investment clubs)

Answer the following questions. For each **affirmative** answer, **attach** the related schedule or form to the partnership return, unless otherwise instructed.

At any time during the fiscal period, was the partnership a member of another partnership (directly or indirectly through one or more partnerships)?	150	☐ Yes	☒ No	T5013 SCH 9
Has the partnership had any transactions, including sections 97 and 98 transactions or subsection 85(2) transfers with its members or employees, other than transactions in the ordinary course of business? (Do not include non-arm's length transactions with non-residents.)	162	☐ Yes	☒ No	T2058, T2059, or T2060
Did the partnership have a total amount over $1 million of reportable transactions with non-arm's length non-residents?	171	☐ Yes	☒ No	T106
Does the partnership have to file Form T1134 in respect of any foreign affiliates in the fiscal period?	172	☐ Yes	☒ No	T1134
Has the partnership made any charitable donations, gifts of cultural or ecological property or federal, provincial, territorial or municipal political contributions?	202	☐ Yes	☒ No	T5013 SCH 2
Does the partnership have a permanent establishment in more than one jurisdiction?	205	☐ Yes	☒ No	T5013 SCH 5
Has the partnership realized any capital gains or incurred any capital losses during the fiscal period?	206	☐ Yes	☒ No	T5013 SCH 6
Does the partnership have any property that is eligible for capital cost allowance?	208	☒ Yes	☐ No	T5013 SCH 8
Does the partnership have any resource-related deductions (not including renounced expenditures)?	212	☐ Yes	☒ No	T5013 SCH 12
Is the partnership allocating any investment tax credits (ITCs) other than the specific ITCs mentioned below that have their own schedule? If **Yes**, attach a document to this return providing a detailed calculation of the partnership's ITCs and their allocation to one or more partners.	231	☐ Yes	☒ No	Calculation and allocation
Did the partnership incur any scientific research and experimental development (SR&ED) expenditures?	232	☐ Yes	☒ No	T661
Does the partnership have a corporation or trust as a member or deemed to be a member under subsection 18.2(12) and interest and financing expenses or interest and financing revenues in the fiscal period?	233	☐ Yes	☒ No	T5013 SCH 130

A partnership that is exempt from filing T5013 SCH 130 because it meets the conditions on **canada.ca/cra-eifel** should answer **No** to question 233.

Did the partnership allocate renounced resource expenses to its members?	252	☐ Yes	☒ No	T5013 SCH 52
Did the partnership own or hold specified foreign property for which the total cost amount, at any time in the fiscal period, was more than CAN $100,000?	259	☐ Yes	☒ No	T1135
Is the partnership allocating any Canadian journalism labour tax credits?	260	☐ Yes	☒ No	T5013 SCH 58
Is the partnership allocating any return of fuel charge proceeds to farmers tax credits?	261	☐ Yes	☒ No	T5013 SCH 63
Is the partnership allocating any carbon capture, utilization and storage (CCUS) ITC, labour requirements addition to tax, or Part XII.7 tax?	263	☐ Yes	☒ No	T5013 SCH 78
Is the partnership allocating any clean technology ITC, labour requirements addition to tax, or recapture of clean technology ITC?	264	☐ Yes	☒ No	T5013 SCH 75
Is the partnership allocating any clean technology manufacturing (CTM) ITC or recapture of CTM ITC?	265	☐ Yes	☒ No	T5013 SCH 76
Is the partnership allocating any clean hydrogen ITC, labour requirements addition to tax, or recapture or recovery of clean hydrogen ITC?	266	☐ Yes	☒ No	T5013 SCH 74

Additional information

Did the partnership use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X Yes	☐ No
Was a slip issued to one or more nominees or agents?	271	☐ Yes	X No
Does the partnership agreement require that the nominee(s) or agent(s) complete and file any of the documents identified on page 2?	272	☐ Yes	X No
Does the partnership have one or more new nominees or agents?	273	☐ Yes	X No
Did the partnership allocate any amount of income tax deducted at source?	274	☐ Yes	X No
Did the partnership make any other election(s) under the Act during the fiscal period?	275	☐ Yes	X No
If **Yes**, attach a copy of each election form to this return.			
Is this partnership the continuation of one or more predecessor partnerships since its last partnership information return was filed?	277	☐ Yes	X No
If you answered **Yes** to line 277, provide the business number(s) of the predecessor partnership(s)	278		
	279		
Was the partnership inactive throughout the fiscal period this information return applies to?	280	☐ Yes	X No
If **Yes**, see Guide T4068 to verify your filing requirements.			
Did members of the partnership immigrate to Canada during the fiscal period?	291	☐ Yes	X No
Did members of the partnership emigrate from Canada during the fiscal period?	292	☐ Yes	X No
If the major business activity is construction, did you have any subcontractors during the fiscal period?	295	☐ Yes	X No
Did the partnership report its farming or fishing income using the cash method?	296	☐ Yes	X No
Is this a publicly traded partnership?	297	☐ Yes	X No
If you answered **Yes** to line 297, did the partnership issue T5008 information slips to report transactions of interests in the partnership?	298	☐ Yes	☐ No

Miscellaneous information

For tax deductions withheld at source, was an NR4 information return filed for the fiscal period?	301	☐ Yes	X No
If you answered **Yes** to line 301, enter the non-resident account number	302		
If you answered **Yes** to line 301, were NR4 slips issued?	303	☐ Yes	☐ No
Is this partnership a specified investment flow-through (SIFT) partnership?	304	☐ Yes	X No
If you answered **Yes** to line 304, enter the taxable non-portfolio earnings for the fiscal period	305		
If you answered **Yes** to line 304, enter the tax payable under Part IX.1 for the fiscal period	306		
Enter the amount of the late-filing penalty from line 307 of the T5013 SCH 52, Summary Information for Partnerships that Allocated Renounced Resource Expenses to their Members	307		
Amount of payment enclosed with this return	308		

Additional information for all partnerships (including tax shelters that are partnerships)

Name and identification number of the partner designated under subsection 165(1.15)

400 Hydro One Sault Ste. Marie Inc.
Name of designated partner

402 [redacted]
Identification number

Additional information for tax shelters only

Principal promoter

500 Last name (print)

501 First name (print)

502 Identification number

Certification

950 I, Yam
Last name (print)

951 Selma
First name (print)

954 Director, Corporate Tax
Position or title

certify that the information given on this information return and in any attached document is correct and complete. I also certify that the method of calculating income, deductions and credits for this fiscal period is consistent with that of the previous fiscal period except as noted in a statement attached to this return.

955 2026-05-05
Year Month Day

Signature of the authorized partner

956 [redacted]
Telephone number

Language of correspondence

Indicate your language of correspondence . . . . . **990** [X] English [ ] French

Privacy notice

Personal information (including the SIN) is collected and used to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be disclosed to other federal, provincial, territorial, aboriginal, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, and to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Info Source at **canada.ca/cra-info-source**.

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PARTNERSHIP'S BALANCE SHEET INFORMATION

T5013 SCHEDULE 100

Partnership name	Partnership account Number	Fiscal period end Year Month Day	Original / Amended
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31	Original [X] Amended [ ]

Is this a NIL schedule? . . . . . 999 Yes [ ] No [X]

Balance sheet information

Account	Description	GIFI		Current year	Prior year
Assets					
	Total current assets	1599	+	6,561,247.00	9,969,000.00
	Total tangible capital assets	2008	+	478,472,000.00	406,209,000.00
	Total accumulated amortization of tangible capital assets	2009	–	111,727,000.00	102,311,000.00
	Total intangible capital assets	2178	+	6,049,000.00	6,674,000.00
	Total accumulated amortization of intangible capital assets	2179	–	1,869,000.00	2,377,000.00
	Total long-term assets	2589	+	1,519,000.00	1,560,000.00
	* Assets held in trust	2590	+		
	Total assets (mandatory field)	2599	=	379,005,247.00	319,724,000.00
Liabilities					
	Total current liabilities	3139	+	178,364,136.00	131,825,000.00
	Total long-term liabilities	3450	+	16,465,000.00	16,504,000.00
	* Subordinated debt	3460	+		
	* Amounts held in trust	3470	+		
	Total liabilities (mandatory field)	3499	=	194,829,136.00	148,329,000.00
Partner's capital					
	Total partners' capital (mandatory field)	3575	+	184,176,111.00	171,395,000.00
	Total liabilities and partners' capital	3585	=	379,005,247.00	319,724,000.00

* Generic item

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T5013 SCHEDULE 125

Form identifier 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Partnership name	Partnership account number	Fiscal period end (Year Month Day)	
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31	Original [X] Amended [ ]

Income statement information

Description	GIFI

Is this a NIL schedule? . . . . . 999 [ ] Yes [X] No

Operating Business Name 0001

Description of the operation 0002

Sequence Number 0003 01

Account	Description	GIFI		Current year	Prior year
Income statement information					
	Total sales of goods and services	8089	+	49,536,000.00	46,851,000.00
	Cost of sales	8518	–		
	Gross profit/loss	8519	=	49,536,000.00	46,851,000.00
	Cost of sales	8518	+		
	Total operating expenses	9367	+	20,786,599.00	19,380,000.00
	Total expenses (mandatory field)	9368	=	20,786,599.00	19,380,000.00
	Total revenue (mandatory field)	8299	+	49,536,000.00	46,851,000.00
	Total expenses (mandatory field)	9368	–	20,786,599.00	19,380,000.00
	Net non-farming income	9369	=	28,749,401.00	27,471,000.00
Farming income statement information					
	Total farm revenue (mandatory field)	9659	+		
	Total farm expenses (mandatory field)	9898	–		
	Net farm income	9899	=		
	Net income/loss before extraordinary items – all operations	9970	=	28,749,401.00	27,471,000.00
	Total other comprehensive income	9998	=	-61,000.00	-43,000.00
Extraordinary items and income (linked to Schedule 140)					
	Extraordinary item(s)	9975	–		
	Legal settlements	9976	–		
	Unrealized gains/losses	9980	+		
	Unusual items	9985	–		
	Current income taxes	9990	–		
	Deferred income tax provision	9995	–		
	Total – Other comprehensive income	9998	+	-61,000.00	-43,000.00
	Net income/loss after taxes and extraordinary items (mandatory field)	9999	=	28,688,401.00	27,428,000.00

Canada Revenue Agency / Agence du revenu du Canada

T5013
Schedule 141
Protected B when completed

General Index of Financial Information (GIFI) – Additional Information

Partnership name	Partnership account number	Fiscal period-end Year Month Day	
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31	[X] Original [ ] Amended

- A partnership needs to complete all parts of this schedule that apply and include it with their partnership information return along with the other GIFI schedules.
- For more information, see Guide RC4088, General Index of Financial Information (GIFI), and Guide T4068, Guide for the Partnership Information Return (T5013 forms).

Part 1 – Information on the person primarily involved with the financial information

Can you identify the person* specified in the heading of Part 1? . . . . . **111** Yes [X] No [ ]

If you answered **no**, go to Part 2.

Does that person have a professional designation in accounting? . . . . . **095** Yes [X] No [ ]

Is that person connected** with the partnership? . . . . . **097** Yes [ ] No [X]

* A person primarily involved with the financial information is a person who has more than a 50% involvement in preparing the financial information that the partnership information return is based on. For example, if three persons prepared the financial information by doing respectively 30%, 30%, and 40% of the work, answer **no** at line 111. If they did respectively 10%, 20%, and 70% of the work, answer **yes** at line 111 and complete Part 1 by referring only to the third person.

** A person connected with a partnership can be: (i) a member of the partnership who owns more than 10% of the partnership units; (ii) an employee of the partnership; or (iii) a person not dealing at arm's length with the partnership.

Part 2 – Type of involvement

Choose one or more of the following options that represent your involvement and that of the person referred to in Part 1:

Completed an auditor's report . . . . . **300** [X]

Completed a review engagement report . . . . . **301** [ ]

Conducted a compilation engagement . . . . . **302** [ ]

Provided accounting services . . . . . **303** [ ]

Provided bookkeeping services . . . . . **304** [ ]

Other . . . . . **305** [ ]

If other, please specify . . . . . **306** _____

Part 3 – Reservations

If you selected option **300** or **301** in Part 2 above, answer the following question:

Has the person referred to in Part 1 expressed a reservation? . . . . . **099** Yes [ ] No [X]

Part 4 – Other information

Were notes to the financial statements prepared? . . . . . **101** Yes [X] No [ ]

Did the partnership have any subsequent events? . . . . . **104** Yes [X] No [ ]

Did the partnership re-evaluate its assets during the fiscal period? . . . . . **105** Yes [X] No [ ]

Did the partnership have any contingent liabilities during the fiscal period? . . . . . **106** Yes [ ] No [X]

Did the partnership have any commitments during the fiscal period? . . . . . **107** Yes [ ] No [X]

Does the partnership have investments in joint ventures? If **yes**, complete question 109 below . . . . . **108** Yes [ ] No [X]

Is the partnership filing joint venture(s) financial statements? . . . . . **109** Yes [ ] No [X]

Part 4 – Other information (continued)

Impairment and fair value changes

In any of the following assets, was an amount recognized in net income or other comprehensive income as a result of an impairment loss in the fiscal period, a reversal of an impairment loss recognized in a previous fiscal period, or a change in fair value during the fiscal period? . . . . . **200** Yes [X] No [ ]

If **yes**, enter the amount recognized:

In net income Increase (decrease)

Property, plant, and equipment	**210**	
Intangible assets	**215**	
Investment property	**220**	
Biological assets	**225**	
Financial instruments	**230**	
Other	**235**	

In other comprehensive income Increase (decrease)

Property, plant, and equipment	**211**	
Intangible assets	**216**	
Financial instruments	**231**	
Other	**236**	61,000.00

Financial instruments

Did the partnership derecognize any financial instrument(s) during the fiscal period (other than trade receivables)?	**250**	Yes [ ]	No [X]
Did the partnership apply hedge accounting during the fiscal period?	**255**	Yes [ ]	No [X]
Did the partnership discontinue hedge accounting during the fiscal period?	**260**	Yes [ ]	No [X]

Adjustments to opening partners' capital

Was an amount included in the opening balance of partners' capital, in order to correct an error, to recognize a change in accounting policy, or to adopt a new accounting standard in the current fiscal period? . . . . . **265** Yes [ ] No [X]

If **yes**, you have to maintain a separate reconciliation.

Part 5 – Information on the person who prepared the partnership information return

If the person who prepared the partnership information return has a professional designation in accounting but is not the person identified in Part 1, choose all of the following options that apply:

Prepared the partnership information return and the financial information contained therein	**310**	[ ]
The client provided the financial statements	**311**	[ ]
The client provided a trial balance	**312**	[ ]
The client provided a general ledger	**313**	[ ]
Other	**314**	[X]

If other, please specify . . . . . **315** HO Tax prepared the return using audited FS

See the privacy notice on your return.

SCHEDULE 100

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 100

Partnership name	Partnership account number	**Fiscal period end** Year Month Day
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31

Is this a NIL schedule? . . . . . 999 Yes ☐ No ☒

Assets – lines 1000 to 2599

1001	2,434,247.00	1400	4,127,000.00	1599	6,561,247.00
1600	236,000.00	1740	19,667,000.00	1741	-9,076,000.00
1900	364,569,000.00	1901	-102,651,000.00	1920	94,000,000.00
2008	478,472,000.00	2009	-111,727,000.00	2010	6,049,000.00
2011	-1,869,000.00	2178	6,049,000.00	2179	-1,869,000.00
2420	1,519,000.00	2589	1,519,000.00	2599	379,005,247.00

Liabilities – lines 2600 to 3499

2620	491,000.00	2860	82,775,000.00	2861	94,847,000.00
2862	250,000.00	2960	1,136.00	3139	178,364,136.00
3320	16,465,000.00	3450	16,465,000.00	3499	194,829,136.00

Partner's capital – lines 3540 to 3575

3545	28,749,401.00	3550	28,688,401.00	3580	-61,000.00
3551	222,208.00	3552	2,869.00	3553	-1,591.00
3560	223,486.00	3561	171,172,792.00	3562	28,685,532.00
3563	-15,905,699.00	3571	183,952,625.00	3575	184,176,111.00
3585	379,005,247.00				

SCHEDULE 125

GENERAL INDEX OF FINANCIAL INFORMATION – GIFI

Form identifier 125

Partnership name	Partnership account number	Fiscal period end Year Month Day
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31

Is this a NIL schedule? . . . . 999 ☐ Yes ☒ No

Description

Sequence number 0003 01

Other comprehensive income – lines 7000 to 7020

7002	-61,000.00

Revenue – lines 8000 to 8299

8000	49,536,000.00	8089	49,536,000.00	8299	49,536,000.00

Cost of sales – lines 8300 to 8519

8519	49,536,000.00

Operating expenses – lines 8520 to 9369

8570	59,000.00	8670	11,788,786.00	8710	-264,247.00
9284	9,203,060.00	9367	20,786,599.00	9368	20,786,599.00
9369	28,749,401.00				

Farming revenue – lines 9370 to 9659

9659	0.00

Farming expenses – lines 9660 to 9899

9898	0.00

Extraordinary items and taxes – lines 9970 to 9999

9970	28,749,401.00	9998	-61,000.00	9999	28,688,401.00

Canada Revenue Agency | Agence du revenu du Canada

T5013
Schedule 1
Protected B when completed

Net Income (Loss) for Income Tax Purposes

Partnership name	Partnership account number	Fiscal period-end Year Month Day	
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31	[X] Original [ ] Amended

- Fill out this schedule to reconcile the partnership's net income (loss) reported on the financial statements and its net income (loss) for income tax purposes.
- All the information requested in this form and in the documents supporting your information return is "prescribed information."
- Fill out this schedule using the instructions in the T4068, Guide for the Partnership Information Return (T5013 forms).
- Fill out a worksheet to identify the source of all the amounts reported on the T5013 information slips.
- Attach the original copy of this completed schedule to the T5013 FIN, Partnership Financial Return.

Is this a NIL schedule? . . . . . 999 [ ] Yes [X] No
(If **yes**, do not use zeroes (000 00), dashes (-), nil, or N/A on the lines.)

Amount calculated on line 9999 from Schedule 125 or Schedule 140			500	28,688,401.00
Add:				
Provision for Part IX.1 specified investment flow through (SIFT) taxes	101			
Amortization/depreciation of tangible assets	104	11,788,786.00		
Amortization of natural resource assets	105			
Amortization of intangible assets	106	59,000.00		
Recapture of capital cost allowance from Schedule 8	107			
Income or loss for tax purposes from partnerships	109			
Loss in equity of affiliates	110			
Loss on disposal of assets per financial statements	111			
Charitable donations and gifts from Schedule 2	112			
Political contributions from Schedule 2	114			
Current fiscal period's holdbacks	115			
Deferred and prepaid expenses	116			
Depreciation in inventory – end of fiscal period	117			
Scientific research and experimental development (SR&ED) expenditures deducted per financial statements	118			
Capitalized interest and property taxes on vacant land	119			
Non-deductible club dues and fees	120			
Non-deductible meals and entertainment expenses	121			
Non-deductible automobile expenses	122			
Non-deductible life insurance premiums	123			
Non-deductible company pension plans	124			
Reserves from financial statements – balance at the end of the fiscal period	126			
Soft costs on construction and renovation of buildings	127			
Salaries and wages paid to partners deducted on financial statements	150			
Cost of products available for sale that were consumed	151			
Personal expenses of the partners paid by the partnership	152			
Dividend rental arrangement compensation payment deductions	154			
Renounced exploration, development and resource property expenses from Schedule 52 deducted per financial statements	155			
Certain fines and penalties	156			
Amount from line 508 on page 2 of this schedule	199	60,753.00		
Total (**Add** lines 101 to 199. Enter this amount on line 501)		11,908,539.00 ▶	501	11,908,539.00
Deduct: Amount from line 511 on page 3 of this schedule			502	19,682,929.49
Net income (loss) for income tax purposes – (line 500 **plus** line 501 **minus** line 502)			503	20,914,010.51
Deduct: Net income (loss) for general partners			504	2,091.40
Net income (loss) for income tax purposes for limited and non-active partners (line 503 **minus** line 504)			505	20,911,919.11

Add:

Accounts payable and accruals for cash basis – closing	201	
Accounts receivable and prepaid for cash basis – opening	202	
Accrual inventory – opening	203	
Accrued dividends – prior fiscal period	204	
Book loss on joint ventures or partnerships	205	
Capital items expensed	206	
Debt issue expense	208	
Deemed dividend income	209	
Deemed interest on loans to non-residents	210	
Deemed interest received	211	
Development expenses claimed in current fiscal period	212	
Dividend stop-loss adjustment	213	
Dividends credited to the investment account	214	
Exploration expenses claimed in current fiscal period	215	
Financing fees deducted in books	216	
Foreign accrual property income	217	
Foreign affiliate property income	218	
Foreign exchange included in retained earnings	219	
Gain on settlement of debt – income inclusion under subsection 80(13)	220	
Interest paid on income debentures	221	
Limited partnership losses	222	
Loss from international banking centres	223	
Mandatory inventory adjustment – included in current fiscal period	224	
Non-deductible advertising	226	
Non-deductible interest	227	
Non-deductible legal and accounting fees	228	
Optional value of inventory – included in current fiscal period	229	
Other expenses from financial statements	230	
Recapture of SR&ED expenditures from Form T661	231	
Resource amounts deducted	232	
Sales tax assessments	234	
Write-down of capital property	236	
Amounts received in respect of qualifying environmental trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – previous fiscal period	238	
Taxable/Non-deductible other comprehensive income items	239	

Other additions:

Description 605	Amount 295
OCI - Revaluation	60,753.00
Benefit Plan payment in excess of exp.	

If you need more space, attach additional schedules. **Total** of column 2 60,753.00 ▶ 296 60,753.00

Total of lines 201 to 239 and line 296 508 60,753.00

Enter the amount from line 508 on line 199 on page 1 of this schedule.

Deduct:

Accounts payable and accruals for cash basis – opening	300	
Accounts receivable and prepaid for cash basis – closing	301	
Accrual inventory – closing	302	
Accrued dividends – current fiscal period	303	
Bad debt	304	
Book income of joint venture or partnership	305	
Equity in income from affiliates	306	
Exempt income under section 81	307	
Income from international banking centres	308	
Mandatory inventory adjustment – included in prior fiscal period	309	
Contributions to a qualifying environmental trust	310	
Non-Canadian advertising expenses – broadcasting	311	
Non-Canadian advertising expenses – printed materials	312	
Optional value of inventory – included in prior fiscal period	313	
Other income from financial statements	314	
Payments made for allocations in proportion to borrowing and bonus interest payments	315	
Contractors' completion method adjustment: revenue net of costs on contracts under 2 years – current fiscal period	316	
Non-taxable/Deductible other comprehensive income items	347	

Other less common deductions:

Description 705	Amount 395
Capitalized interest	5,008,260.00
Deferred revenue - customer contribution	279,060.00
Regulatory Asset & Liab. Adjustment	
OPEB payment in excess of P&L expense	20,063.00

If you need more space, attach additional schedules. **Total** of column 2 5,307,383.00 ▶ 396 5,307,383.00

Total of lines 300 to 347 and line 396 509 5,307,383.00

Other deductions:

Gain on disposal of assets per financial statements	401	
Non-taxable dividends under section 83	402	
Capital cost allowance from Schedule 8	403	14,375,546.49
Terminal loss from Schedule 8	404	
Foreign non-business tax deduction under subsection 20(12)	407	
Prior fiscal period's holdbacks	408	
Deferred and prepaid expenses	409	
Depreciation in inventory – end of prior fiscal period	410	
SR&ED expenditures claimed in the fiscal period from Form T661 (line 460)	411	
Reserves from financial statements – balance at the beginning of the fiscal period	414	
Patronage dividends	416	
Contributions to deferred income plans	417	

Total (**Add** lines 401 to 417. Enter this amount on line 510) 14,375,546.49 ▶ 510 14,375,546.49

Total (**Add** lines 509 and 510) 511 19,682,929.49

Enter the amount from line 511 on line 502 on page 1 of this schedule.

See the privacy notice on your return.

Attached Schedule with Total

Other additions – Amount

Title Other additions – Amount

Explanatory note

Description	Operator (Note)	Amount
Project Cancellation Costs for Class47 per Tab8.5		
rounding diff.	+	
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

Attached Schedule with Total

Other less common deductions – Montant

Title Other less common deductions – Montant

Explanatory note

Description	Operator (Note)	Amount
	+	
	Total	

Note: The calculations are performed one at a time, from the first to the last line, and not according to the priority rules of the operations. For example, the formula 1+2*3 will not result in the same thing as the formula 1+3*2.

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T5013
Schedule 8
Protected B when completed

Capital Cost Allowance (CCA)

Partnership name	Partnership account number	Fiscal period end Year Month Day	
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31	[X] Original [ ] Amended

- Fill out this schedule to calculate the amount of capital cost allowance (CCA) the partnership is claiming for the fiscal period, to account for acquisitions or dispositions of depreciable property, or to designate immediate expensing property, or both.
- Unless otherwise stated, all legislative references are to the Income Tax Act.
- Fill out this schedule using the instructions in the T4068, Guide for the Partnership Information Return (T5013 forms).
- If you do not have enough space to list all the information, use an additional T5013 Schedule 8.
- Attach the original copy of this completed schedule to the T5013 FIN, Partnership Financial Return.

Part 1 – Agreement between associated eligible persons or partnerships (EPOPs)

Are you associated in the fiscal period with one or more EPOPs with which you have entered into an agreement under subsection 1104(3.3) of the Income Tax Regulations? . . . . . **105** Yes [ ] No [X]

If you answered **yes**, fill out Part 1. Otherwise, go to Part 2.

Enter a percentage assigned to each associated EPOP (including your partnership) as determined in the agreement.

This percentage will be used to allocate the immediate expensing limit. The total of all the percentages assigned under the agreement should not exceed 100%. If the total is more than 100%, then the associated group has an immediate expensing limit of nil. For more information about the immediate expensing limit, see note 12 in Part 3.

	1 Name of EPOP **110**	2 Identification number **Note 1** **115**	3 Percentage assigned under the agreement **120**
1			%
2			%
3			%
4			%
5			%
6			%
7			%
8			%
		Total	%

Immediate expensing limit allocated to the partnership (see **note 2**) . . . . . **125** _____

Note 1: The identification number is the social insurance number, business number, or partnership account number of the EPOP.

Note 2: Multiply 1.5 million by the percentage assigned to your partnership in column 3.

Part 2 – Income earned from the source in which the designated immediate expensing property (DIEP) is used

The source refers to the business or property from which the income was earned and in which the DIEP is used. For more information about DIEP, see note 5 in Part 3.

Are you a Canadian partnership of which all of the members were, throughout the fiscal period, Canadian-controlled private corporations (CCPC), individuals (other than trusts) resident in Canada or a combination thereof? . . . . . **150** Yes ☐ No ☒

If you answered **yes**, fill out Part 2. Otherwise, go to Part 3.

Is there more than one source of income? . . . . . **155** Yes ☐ No ☐

If you answered **no**, enter the income of that source of income (net income for income tax purposes before any CCA deductions) . . . . . **156** _____

If the answer is **yes**, fill out the table below.

	1 Source of income **160**	2 Income before any CCA deductions from each source (if the income is a loss or nil, enter "0") **165**	3 Aggregate amount of DIEP used for each source **170**
1			
2			
3			
4			
5			
6			
7			
8			

Part 3 – CCA calculation

	1 Class number Note 3 200	2 Undepreciated capital cost (UCC) at the beginning of the fiscal period 201	3 Cost of acquisitions during the fiscal period (new property must be available for use) Note 4 203	4 Cost of acquisitions from column 3 that are designated immediate expensing property (DIEP) Note 5 232	5 Adjustments and transfers (show amounts that will reduce the UCC in brackets) Note 6 205	6 Amount from column 5 that is assistance received or receivable during the fiscal period for a property, subsequent to its disposition Note 7 221	7 Amount from column 5 that is repaid during the fiscal period for a property, subsequent to its disposition Note 8 222	8 Proceeds of dispositions Note 9 207
1	1	55,625,678.46	568,614.00					
2	8	668,162.15	2,339,276.00					
3	10	3,082.28						
4	47	84,650,081.48	56,084,183.00					
5	50	27,276.80						
6	14.1	2,931,209.20						
7	6	178,636.26						
8	13	0.39						
9	13	411,720.41						
10	13	0.04						

	9 Proceeds of dispositions of the DIEP (enter amount from column 8 that relates to the DIEP reported in column 4) 234	10 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) Note 10	11 UCC of the DIEP (enter the UCC amount that relates to the DIEP reported in column 4) Note 11 236	12 Immediate expensing Note 12 238	13 Cost of acquisitions on remainder of Class (column 3 **minus** column 12)	14 Cost of acquisitions from column 13 that are accelerated investment incentive property (AIIP) or properties included in Classes 54 to 56 Note 13 225	15 Remaining UCC (column 10 **minus** column 12) (if negative, enter "0")	16 Proceeds of disposition available to reduce the UCC of AIIP and property included in Classes 54 to 56 (column 8 **plus** column 6 **minus** column 13 **plus** column 14 **minus** column 7) (if negative, enter "0")
1		56,194,292.46			568,614.00	568,614.00	56,194,292.46	
2		3,007,438.15			2,339,276.00	2,339,276.00	3,007,438.15	
3		3,082.28					3,082.28	
4		140,734,264.48			56,084,183.00	56,084,183.00	140,734,264.48	
5		27,276.80					27,276.80	
6		2,931,209.20					2,931,209.20	
7		178,636.26					178,636.26	
8		0.39					0.39	
9		411,720.41					411,720.41	
10		0.04					0.04	
		Totals						

Part 3 – CCA calculation (continued)

	17 Net capital cost additions of AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 14 **minus** column 16) (if negative, enter "0")	18 UCC adjustment for AIIP and property included in Classes 54 to 56 acquired during the fiscal period (column 17 **multiplied** by the relevant factor) **Note 14**	19 UCC adjustment for property acquired during the fiscal period other than AIIP and property included in Classes 54 to 56 (0.5 **multiplied** by the result of column 13 **minus** column 14 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") **Note 15** **224**	20 CCA rate % **Note 16** **212**	21 Recapture of CCA **Note 17** **213**	22 Terminal loss **Note 18** **215**	23 CCA (for declining balance method, the result of column 15 **plus** column 18 **minus** column 19, **multiplied** by column 20, or a lower amount, **plus** column 12) **Note 19** **217**	24 UCC at the end of the fiscal period (column 10 **minus** column 23) **220**
1	568,614.00			4.00			2,247,771.70	53,946,520.76
2	2,339,276.00			20.00			601,487.63	2,405,950.52
3				30.00			924.68	2,157.60
4	56,084,183.00			8.00			11,258,741.16	129,475,523.32
5				55.00			15,002.24	12,274.56
6				5.00			154,607.64	2,776,601.56
7				10.00			17,863.63	160,772.63
8								0.39
9							79,147.81	332,572.60
10								0.04
					230	**240**	**250**	
				Totals			14,375,546.49	

Enter the amount from line 230 on line 107 of T5013 SCH 1, Net Income (Loss) for Income Tax purposes. Enter each partner's share of the amount from line 230 in box 252 of the T5013 slips, Statement of Partnership Income, if the partnership is filing a T5013 SCH 130, Partnership Interest and Financing Expenses and Interest and Financing Revenues for the fiscal period.

Enter the amount from line 240 on line 404 of T5013 SCH 1. Enter each partner's share of the amount from line 240 in box 251 of the T5013 slips if the partnership is filing a T5013 SCH 130 for the fiscal period.

Enter the amount from line 250 on line 403 of T5013 SCH 1.

Note 3: If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101.

Note 4: Include any property acquired in previous fiscal periods that has now become available for use, net of any assistance received or entitled to be received in the fiscal period from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exclusions from the half-year rule. Do not include any amount in column 3 in respect of property included in column 5 (see note 6). See Guide T4068 for more information about the cost of acquisitions during the fiscal period.

Note 5: A DIEP reported in column 4 is a property acquired after December 31, 2021, by a Canadian partnership (all of the members of which were, throughout the period, Canadian-controlled private corporations, individuals (other than trusts) resident in Canada or a combination thereof) that becomes available for use before 2025 (if all the members are individuals throughout the fiscal period), or before 2024 in any other case. The property is designated as such on or before the day that is 12 months after the filing due date of an information return under section 229 of the Regulations by any member of the partnership for the fiscal period to which the designation relates. It includes all capital property subject to the CCA rules, if certain conditions are met, other than property included in Classes 1 to 6, 14.1, 17, 47, 49, and 51. A property can only qualify as DIEP in the fiscal period in which it becomes available for use. See subsection 1104(3.1) of the Regulations for more information.

If there is more than one source of income, the total amount of DIEP reported in Part 2 (total of column 3) should be equal to the total amount of DIEP reported in Part 3 (total of column 4).

Part 3 – CCA calculation (continued)

Note 6: Enter in column 5, "Adjustments and transfers," amounts that increase or reduce the UCC (column 10). Items that increase the UCC include amounts transferred under subsection 97(2). Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the fiscal period for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See Guide T4068 for other examples of adjustments and transfers to include in column 5.

Also include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor at least 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 7: Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 8: Include all amounts you have repaid during the fiscal period for any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance, or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Also include property acquired in a non-arm's length transaction [other than by virtue of a right referred to in paragraph 251(5)(b)] if the property was a depreciable property acquired by the transferor less than 364 days before the end of your fiscal period and continuously owned by the transferor until it was acquired by you.

Note 9: For each property disposed of during the fiscal period, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).

If the cost of a zero-emission passenger vehicle (or a passenger vehicle that was, at any time, a DIEP) exceeds the prescribed amount and it is disposed of to a person or partnership with which you deal at arm's length, the proceeds of disposition will be adjusted based on a factor equal to the prescribed amount as a proportion of the actual cost of the vehicle. The actual cost of the vehicle will be adjusted for payment or repayment of government assistance.

Note 10: If the amount in column 5 (as shown in brackets) reduces the UCC, you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purpose of the calculation.

Note 11: The amount to enter in column 11 must not exceed the amount in column 10. If it does, enter in column 11 the amount from column 10. If the amount determined in column 10 is zero or a negative amount, enter "0". The only amounts incurred before 2022, to be included in this column are certain inventory purchases from arm's length persons or partnerships where the conditions in paragraphs 1100(0.3)(a) to (c) of the Regulations are met.

Note 12: Immediate expensing applies to a DIEP included in column 11. The total immediate expensing for the fiscal period (total of column 12) is limited to the lesser of:

- Immediate expensing limit: it is equal to one of the following five amounts, whichever is applicable:
  - $1.5 million, if you are not associated with any other EPOP in the fiscal period
  - amount from line 125, if you are associated in the fiscal period with one or more EPOPs
  - nil, if the total of the percentages assigned in Part 1 is more than 100% or you are associated in the fiscal period with one or more EPOPs and have not filed an agreement in prescribed form as required under subsection 1104(3.3) of the Regulations
  - the amount determined under subsection 1104(3.5) of the Regulations for any second or subsequent fiscal periods ending in a calendar year, if you have two or more fiscal periods ending in the calendar year in which you are associated with another EPOP that has a tax year ending in that calendar year
  - any amount allocated by the minister under subsection 1104(3.4) of the Regulations
- UCC of the DIEP: total of column 11
- Income earned from the source in which the DIEP is used: amount from line 156 or relevant source of income from line 165

The immediate expensing limit has to be prorated if your fiscal period is less than 51 weeks. You cannot carry forward any unused amount of the immediate expensing limit.

Note 13: An AIIP is a property (other than property included in Classes 54 to 56) that you acquired after November 20, 2018, and that became available for use before 2028.

Classes 54 and 55 include zero-emission vehicles that you acquired after March 18, 2019, and that became available for use before 2028.

Class 56 applies to eligible zero-emission automotive equipment and vehicles (other than motor vehicles) that are acquired after March 1, 2020, and that became available for use before 2028.

See Guide T4068 for more information.

Part 3 – CCA calculation (continued)

Note 14: The relevant factors for property of a class in Schedule II, that is an AIIP or included in Classes 54 to 56, are:

- 2 1/3 for property in Classes 43.1, 54 and 56 that became available for use before 2024 or 1 ½ if it became available for use in 2024 or 2025
- 1 1/2 for property in Class 55 that became available for use before 2024 or 7/8 if it became available for use in 2024 or 2025
- 1 for property in Classes 43.2 and 53 that became available for use before 2024 or 1/2 if it became available for use in 2024 or 2025
- 0 for property in Classes 12, 13, 14, 15, and 59, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 19 for additional information)
- 0.5 for all other property (including property in Class 10.1) that is an AIIP that became available for use before 2024 or 0 if it became available for use after 2023

If the fiscal period does not follow the calendar year, the relevant factor is determined under subsection 1100(2.01) of the Regulations.

Note 15: The UCC adjustment for property acquired during the fiscal period (also known as the half-year rule or 50% rule) does not apply to certain property (including AIIP and property included in Classes 54 to 56).

For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 16: Enter a rate only if you are using the declining balance method. For any other method (for example, the straight-line method, where calculations are always based on the cost of acquisitions), enter "N/A". Then enter the amount you are claiming in column 23.

Note 17: If the amount in column 10 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 10 in column 21 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1. However, they do apply to a passenger vehicle that was, at any time, a DIEP.

Note 18: If no property is left in the class at the end of the fiscal period and there is still a positive amount in column 10, you have a terminal loss. If applicable, enter the positive amount from column 10 in column 22. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 19: If the fiscal period is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See Guide T4068 for more information.

For property in Class 10.1 disposed of during the fiscal period, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the fiscal period.

For AIIP listed below, the maximum first fiscal period allowance you can claim is determined as follows:

- Class 13: if the capital cost of the property was incurred before 2024, the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the fiscal period (before any CCA deduction), and in any other case, the amount for the year calculated in accordance with Schedule III of the Regulations
- Class 14: the lesser of 150% (if the property becomes available for use in the year and before 2024) or 125% (if the property becomes available for use in the year and after 2023) of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the fiscal period (before any CCA deduction)
- Class 15: the lesser of 150% (if the property is acquired in the year and before 2024) or 125% (if the property is acquired in the year and after 2023) of an amount calculated on the basis of a rate per cord, board foot, or cubic metre cut in the fiscal period and the UCC at the end of the fiscal period (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% (for property acquired in the year and before 2024) or 33 1/3% (in any other case) of the capital cost of the property and the UCC at the end of the fiscal period (before any CCA deduction)
- Natural Gas Liquefaction: The additional allowances in respect of natural gas liquefaction under paragraphs 1100(1)(a.3) and (yb) of the Regulations are eligible for the accelerated investment incentive.

The AIIP provisions also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more details.

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Partner's Ownership and Account Activity

Protected B when completed

T5013
Schedule 50

Partnership name	Partnership account number	Fiscal period end (Year Month Day)	
Hydro One Sault Ste. Marie LP	[redacted]	2025-12-31	[X] Original [ ] Amended

- Fill out this schedule to reconcile each partner's interest in the partnership (including partners who retired during the fiscal period).
- All the information requested in this form and in the documents supporting your information return is "prescribed information".
- Fill out this schedule using the instructions in Guide T4068, *Guide for the Partnership Information Return (T5013 forms)*.
- If you do not have enough space to list all the information, use an additional Schedule 50.
- Attach the original copy of this completed schedule to Form T5013 FIN, *Partnership Financial Return*.

Number of partners	010	2
Number of partners who disposed of all, or part of, their partnership interest	011	
Number of nominees or agents	012	
Total of all amounts from line 220	015	20,914,010.51

Partner 1

Ownership						Fiscal period's income (loss) allocation	Account activity
100 Partner name	101 Partner identification number	105 Type of partner	106 Partner code	107 Percentage (%) of partner's interest	110 Did the partner dispose of an interest during the fiscal period?	220 Partner's share of the net income (loss)	300 Cost base
Hydro One Sault Ste Marie Inc	[redacted]	2	2	0.0100	[ ] Yes [X] No	2,091.40	N/A

Account activity (continued) / **At-risk amount (ARA)** (for limited partners only)

310 Cost of units acquired during the fiscal period	320 Partner's share of the previous fiscal period's net income (loss)	330 Capital contributions in the fiscal period	340 Withdrawals in the fiscal period	350 Other adjustment	410 Partner's share of the fiscal period's net income	420 Partner's share in certain reductions of resource expenses for the fiscal period	430 Non-arm's length debt owing and/or benefits receivable
	2,326.98						

Partner 2

Ownership						Fiscal period's income (loss) allocation	Account activity
100 Partner name	101 Partner identification number	105 Type of partner	106 Partner code	107 Percentage (%) of partner's interest	110 Did the partner dispose of an interest during the fiscal period?	220 Partner's share of the net income (loss)	300 Cost base
Hydro One Sault Ste Marie Holdings LP	[redacted]	3	0	99.9900	[ ] Yes [X] No	20,911,919.11	91195480.35

Account activity (continued) / **At-risk amount (ARA)** (for limited partners only)

310 Cost of units acquired during the fiscal period	320 Partner's share of the previous fiscal period's net income (loss)	330 Capital contributions in the fiscal period	340 Withdrawals in the fiscal period	350 Other adjustment	410 Partner's share of the fiscal period's net income	420 Partner's share in certain reductions of resource expenses for the fiscal period	430 Non-arm's length debt owing and/or benefits receivable
	23,267,496.20		-15,907,264.00		20,911,919.11		

Approval code: RC-25-P010

Partner 3	Ownership						Fiscal period's income (loss) allocation	Account activity
100	101	105	106	107	110		220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?		Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No			

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 4	Ownership						Fiscal period's income (loss) allocation	Account activity
100	101	105	106	107	110		220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?		Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No			

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

Partner 5	Ownership						Fiscal period's income (loss) allocation	Account activity
100	101	105	106	107	110		220	300
Partner name	Partner identification number	Type of partner	Partner code	Percentage (%) of partner's interest	Did the partner dispose of an interest during the fiscal period?		Partner's share of the net income (loss)	Cost base
					☐ Yes ☐ No			

Account activity (continued)					At-risk amount (ARA) (for limited partners only)		
310	320	330	340	350	410	420	430
Cost of units acquired during the fiscal period	Partner's share of the previous fiscal period's net income (loss)	Capital contributions in the fiscal period	Withdrawals in the fiscal period	Other adjustment	Partner's share of the fiscal period's net income	Partner's share in certain reductions of resource expenses for the fiscal period	Non-arm's length debt owing and/or benefits receivable

See the privacy notice on your return.

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Fiscal period-end / Exercice se terminant le — YYYY-MM-DD / AAAA-MM-JJ: 2025-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Hydro One Sault Ste. Marie LP
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 2	003: CAN	004: 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001: [redacted]	010:	020: 2,091 40

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006: [redacted]	005: 0.010000	030:	040: 1,437 55

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Sault Ste Marie Inc
483 Bay Street
8th Floor South Tower
Toronto ON M5G 2P5

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116		2,091 40	118		4,953 60

Box – Case	Code	Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Attach to your income tax return 2
Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2

See recipient instructions
Voir les instructions du bénéficiaire

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le — YYYY-MM-DD / AAAA-MM-JJ: 2025-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Hydro One Sault Ste. Marie LP
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on back*) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 2	003: CAN	004: 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001: [redacted]	010:	020: 2,091 40

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006: [redacted]	005: 0.010000	030:	040: 1,437 55

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Sault Ste Marie Inc
483 Bay Street
8th Floor South Tower
Toronto ON M5G 2P5

Box / Case	Code	Amount – Montant	Box / Case	Code	Amount – Montant
116		2,091 40	118		4,953 60

Box – Case	Code	Other information – Autres renseignements

Box / Case	Code	Amount – Montant	Box / Case	Code	Amount – Montant

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Keep this slip for your records 3
Bénéficiaire – Conservez pour vos dossiers 3

See recipient instructions
Voir les instructions du bénéficiaire

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le — YYYY-MM-DD / AAAA-MM-JJ: 2025-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Hydro One Sault Ste. Marie LP
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002 — 0	003 — CAN	004 — 4

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001 — [redacted]	010 — 20,911,919.11	020 —

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006 — [redacted]	005 — 99.990000	030 —	040 — 14,374,108.94

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

▶ Hydro One Sault Ste Marie Holdings LP
483 Bay Street
8th Floor South Tower
Toronto ON M5G 2P5

Box – Case	Code	Amount – Montant	Box – Case	Code	Amount – Montant
104		20,911,919.11	105		130,264,230.30
106		130,264,230.30	118		49,531,046.40

Box – Case	Code	Other information – Autres renseignements

Box – Case	Code	Amount – Montant	Box – Case	Code	Amount – Montant

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

For Recipient – Attach to your income tax return 2
Bénéficiaire – Annexez à votre déclaration d'impôt sur le revenu 2

See recipient instructions
Voir les instructions du bénéficiaire

Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le: YYYY-MM-DD / AAAA-MM-JJ: 2025-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Hydro One Sault Ste. Marie LP
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on back*) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 0	003: CAN	004: 4

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001: [redacted]	010: 20,911,919 11	020:

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006: [redacted]	005: 99.990000	030:	040: 14,374,108 94

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Sault Ste Marie Holdings LP
483 Bay Street
8th Floor South Tower
Toronto ON M5G 2P5

Box / Case	Code	Amount – Montant	Box / Case	Code	Amount – Montant
104		20,911,919 11	105		130,264,230 30
106		130,264,230 30	118		49,531,046 40

Box – Case	Code	Other information – Autres renseignements

Box / Case	Code	Amount – Montant	Box / Case	Code	Amount – Montant

See the privacy notice on your return
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For Recipient – Keep this slip for your records 3
Bénéficiaire – Conservez pour vos dossiers 3

See recipient instructions
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Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le — YYYY-MM-DD / AAAA-MM-JJ: 2025-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Hydro One Sault Ste. Marie LP
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 2	003: CAN	004: 3

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001: [redacted]	010:	020: 2,091 40

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006: [redacted]	005: 0.010000	030:	040: 1,437 55

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Sault Ste Marie Inc
483 Bay Street
8th Floor South Tower
Toronto ON M5G 2P5

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant
116		2,091 40	118		4,953 60

Box – Case	Code	Other information – Autres renseignements

Box Case	Code	Amount – Montant	Box Case	Code	Amount – Montant

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Canada Revenue Agency | Agence du revenu du Canada

Fiscal period-end / Exercice se terminant le — YYYY-MM-DD / AAAA-MM-JJ: 2025-12-31

T5013

Statement of Partnership Income
État des revenus d'une société de personnes

Filer's name and address – Nom et adresse du déclarant

Hydro One Sault Ste. Marie LP
483 Bay Street, 8th Floor, South Tower
Toronto ON M5G 2P5

Tax shelter identification number (see **statement** on back *) / Numéro d'inscription de l'abri fiscal (lisez **l'énoncé** au dos *)

Partner code / Code de l'associé	Country code / Code du pays	Recipient type / Genre de bénéficiaire
002: 0	003: CAN	004: 4

Partnership account number (15 characters) / Numéro de compte de la société de personnes (15 caractères)	Total limited partner's business income (loss) / Total du revenu (de la perte) d'entreprise du commanditaire	Total business income (loss) / Total du revenu (de la perte) d'entreprise
001: [redacted]	010: 20,911,919 11	020:

Partner's identification number / Numéro d'identification de l'associé	Partner's share (%) of partnership / Part de l'associé (%) dans la société de personnes	Total capital gains (losses) / Total des gains (pertes) en capital	Capital cost allowance / Déduction pour amortissement
006: [redacted]	005: 99.990000	030:	040: 14,374,108 94

Partner's name and address – Nom et adresse de l'associé

Last name (print) – Nom de famille (en lettres moulées) | First name – Prénom | Initials – Initiales

Hydro One Sault Ste Marie Holdings LP
483 Bay Street
8th Floor South Tower
Toronto ON M5G 2P5

Box / Case	Code	Amount – Montant	Box / Case	Code	Amount – Montant
104		20,911,919 11	105		130,264,230 30
106		130,264,230 30	118		49,531,046 40

Box – Case	Code	Other information – Autres renseignements

Box / Case	Code	Amount – Montant	Box / Case	Code	Amount – Montant

See the privacy notice on your return
Consultez l'avis de confidentialité dans votre déclaration

Canada Revenue Agency | Agence du revenu du Canada

Protected B when completed

Summary of Partnership Income

T5013 Summary

Fill out this summary and the related slips using the instructions in Guide T4068, Guide for the Partnership Information Return (T5013 Forms).

The **partnership information return** is made up of three parts:

- T5013 FIN, Partnership Financial Return
- All the T5013 schedules the partnership has to file, depending on its fiscal situation
- T5013, Statement of Partnership Income, slips and this summary

If you make certain payments to a non-resident of Canada, the amounts must be reported on an NR4 return. For more information, see Guide T4061, NR4 – Non-Resident Tax Withholding, Remitting and Reporting.

For more information on filing the partnership information return, go to **canada.ca/t5013-filing-requirements**.

Do not use this area.

50 | | | | | 1616

Part 1 – Identification

Partnership's account number	Fiscal period-start (Year Month Day)	Fiscal period-end (Year Month Day)
[redacted]	2025-01-01	2025-12-31

Name of the partnership	Postal or ZIP code
Hydro One Sault Ste. Marie LP	M5G 2P5

Are you a nominee or an agent? (If yes, provide the following information) . . . . . ☐ Yes ☒ No

Nominee or agent's account number	Name of the nominee or agent	Postal or ZIP code

Is the partnership a tax shelter? . . . . . ☐ Yes ☒ No

If yes, enter the tax shelter identification number (TS) . . . . . .

Part 2 – Totals from T5013 slips

Total number of T5013 information slips attached	009	2
Total limited partner's business income (loss)	010	20,911,919.11
Total business income (loss)	020	2,091.40
Total capital gains (losses)	030	
Capital cost allowance	040	14,375,546.49

Fill out the six boxes below using the information found on the T5013 slips

Canadian and foreign net rental income (loss)	110	
Professional income (loss)	120	
Renounced Canadian exploration expenses	190	
Renounced Canadian development expenses	191	
Expenses qualifying for an ITC *	194	
Total carrying charges	210	

* Line 194 is the total of all the amounts in boxes 194 and 239 of all the T5013 slips.

Part 3 – Contact information

076 Person to contact about this summary	078 Telephone number
Yam Selma	[redacted]

Part 4 – Certification

I certify that the information given in this summary and the related slips is correct and complete.

Year Month Day	Signature of authorized person	Position or office
2026-05-05		Director, Corporate Tax

Prepared by	Year Month Day
	2026-05-05

Part 5 – Privacy notice

Personal information is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 224 on Information about Programs and Information Holdings at **canada.ca/cra-information-about-programs**.

PROPERTY TAXES AND RIGHTS PAYMENTS

1.0 INTRODUCTION

This schedule describes Hydro One's expenses related to taxes other than income and capital taxes. These taxes consist of various property taxes, including payments for the right to cross and/or occupy land not owned by Hydro One. Sections 2.0 and 3.0 present these taxes for the Transmission and Distribution lines of business, respectively.

For Transmission and Distribution, the forecasted property tax expenses and rights payments are generally higher than historical years, as the forecast years reflect higher tax rates, increases in the assessed value of Hydro One properties, and increasing land values.

2.0 TRANSMISSION TAXES

In respect of the Transmission business, Table 1 summarizes property tax and rights payments over the historical, bridge, and test years.

Table 1 - Taxes - Transmission ($M)[1]

Description	Historical				Bridge	Test
	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
Property Tax	63.9	60.4	62.5	67.2	68.5	70.2
Rights Payments	8.6	8.5	11.0	10.6	10.7	19.5
Total	**72.4**	**68.8**	**73.5**	**77.8**	**79.2**	**89.7**

The 2028 Test Year expenditure for Transmission Property Tax and Rights Payments is $89.7M, a $17.2M increase over 2023 actuals, and a $15.3M increase over the average of the last rate period (2023-2027).

[1] Figures presented in the tables may not sum to the totals shown due to rounding.

2.1 PROPERTY TAXES

Like every other landowner in Ontario, Hydro One is responsible for the payment of property taxes. Property taxes for Hydro One are regulated under Ontario's *Electricity Act, 1998*, the *Municipal Act, 2001*, the *Assessment Act*, and the *Indian Act*. Property taxes are levied on Hydro One's land and buildings, including service centre sites, transmission stations and transmission lines. Hydro One pays property tax to 385 municipalities each year. The Municipal Property Assessment Corporation (MPAC) assigns the total assessed value, which is updated using the same schedule as for the rest of the province. MPAC issues Notices of Assessments, which are received and reviewed by Hydro One for accurate valuation and tax classification each year. Any incorrect classes or over-valuations are appealed through the MPAC or the Assessment Review Board.

Lands owned by Hydro One are taxed based on a property's current value assessment (CVA). However, CVA is not assessed every year. The Province of Ontario, through the Ministry of Finance, issued a province wide reassessment for the 2017 – 2020 taxation years whereby the CVA of each property in Ontario was based on a valuation date of January 1, 2016. During the COVID-19 pandemic, Ontario postponed the 2020 assessment update. The Ministry of Finance has not yet announced when the next re-assessment will occur. Accordingly, property taxes currently continue to be based on a January 1, 2016 valuation date.

Despite currently stable CVAs, Hydro One's property taxes are subject to increases due to annual tax rate increases by municipalities and regions in which they are located.

A summary breakdown of annual transmission property taxes is presented in Table 2 below.

Table 2 - Breakdown of Total Property Tax Expense - Transmission ($M)

Description	Historical				Bridge	Test
	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
Stations and Buildings, including Proxy Tax	27.3	26.5	27.1	30.6	30.4	32.9
Transmission Lines	36.6	33.9	35.4	36.6	38.1	37.3
Total	**63.9**	**60.4**	**62.5**	**67.2**	**68.5**	**70.2**

The 2028 Test Year expenditure for Transmission Property Tax is $70.2M, a $6.3M increase over 2023 actuals, and a $5.7M increase over the average of the last rate period (2023-2027).

The components of Table 2 are discussed in the subsections below.

2.1.1 TRANSMISSION STATIONS AND BUILDINGS

Property taxes for transmission stations and buildings are the product of two separate assessment methods: one for land and one for buildings.

The lands containing the transmission stations and buildings are assessed by MPAC using the CVA method - the valuation method used for other property owners within the province.

Transmission station buildings are assessed at a statutory rate of $86.11 per square metre, pursuant to the *Assessment Act*. In addition to this statutory rate, transmission stations are subject to additional property tax payments called property “proxy taxes.” These amounts are payable to the Minister of Finance under Ontario Regulation 423/11 of the *Electricity Act, 1998*. The additional tax is the difference between the statutory rate for transmission station buildings and the municipal tax that would apply to the buildings if they were taxed using the CVA method. This amount is calculated each year for each transmission station building owned by Hydro One.

Other municipal property tax costs relate to costs on other sundry properties, such as transmission communication towers and administrative buildings.

From 2023-2025, property taxes for stations and buildings remained roughly constant. Forecasted property taxes increase over the 2026 to 2028 period due to anticipated annual property rate increases, which are expected to continue into 2028 and beyond.

2.1.2 TRANSMISSION LINES

Hydro One's transmission line corridors are assessed, and municipal taxes are calculated at a rate per acre of owned corridor land. These rates are established by Ontario Regulation 387/98 (Tax Matter – Taxation of Certain Railway, Power Utility Lands) made under the *Municipal Act, 2001* and Ontario Regulation 494/98 made under the *Education Act*, all as amended. As payments are made based on an area of land multiplied by a legislated rate, appeals must be based on corrections to the area of the property, or on the decision to re-classify a property as outside the utility corridor tax class.

An additional amount is paid annually to various First Nations Bands as payment in lieu of taxes with respect to transmission assets on reserves. Since June 1985, Section 83 of the *Indian Act* has provided for taxation by First Nations of property interests on their reserve lands. Hydro One makes payments in lieu of taxes similar to taxes paid to municipalities that have Hydro One Transmission facilities within their boundaries.

Transmission line property tax has varied through the 2023-2025 historic actual period, reflecting variations in the size of Hydro One's transmission land base. Similarly, the forecast reflects the impact of anticipated land acquisitions in 2026-2028.

2.2 TRANSMISSION RIGHTS PAYMENTS

In some circumstances, Hydro One must make rights payments in respect of its transmission lines and facilities that cross or occupy land not owned by the company. These payments are made under agreements with railway companies (e.g., Canadian Pacific and Kansas City Southern (CPKC), Canadian National) and governmental bodies

(e.g., Ministry of Natural Resources, Metrolinx). Hydro One also makes payments in respect of its transmission assets that cross and/or occupy First Nations Reserves and other lands held for First Nations.

Table 3 - Rights Payments - Transmission ($M) [2]

Description	Historical				Bridge	Test
	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
Right Payment associated with non-First Nations	5.4	4.8	5.2	5.5	5.6	13.9
Right Payment associated with First Nations	3.2	3.6	5.8	5.1	5.1	5.5
Rights Payments Total	**8.6**	**8.5**	**11.0**	**10.6**	**10.7**	**19.5**

The 2028 Test Year expenditure for Transmission Rights Payments is $19.5M, a $10.9M increase over 2023 actuals, and a $9.6M increase over the average of the last rate period (2023-2027).

The payments to railway companies and government entities, for the right to have transmission assets cross and/or occupy their properties, are determined according to the terms of agreements governing the respective assets. The forecast payments under these agreements increase from $5.6M in 2027 to $13.9M in 2028 due to a combination of new rights acquired in perpetuity and renewal of existing long-term agreements. Existing agreements contain rental review provisions allowing for rent increases. Hydro One anticipates increased costs upon contract renewal as a result of increased land values in the market.

Following the increased forecast in 2028, payments under non-First Nations rights payment agreements are not anticipated to increase materially over the remainder of the 2028–2032 period, including as agreements come up for renewal.

[2] Figures presented in the tables may not sum to the totals shown due to rounding.

Through agreements or permits granted by Indigenous Services Canada (ISC), Hydro One has approval for its transmission and distribution facilities (that is, lines and transformer and distribution stations), to cross and/or occupy First Nation Reserves. Some of these permits and agreements require Hydro One to pay annual rental fees. Payments are administered by ISC with the exception of First Nation Bands under the *Framework Agreement on First Nation Land Management Act*, in which case Hydro One compensates the First Nation Band directly.

The transfer orders by which Hydro One acquired Ontario Hydro's electricity transmission, distribution and energy services businesses as of April 1, 1999 did not transfer title to some assets located on lands held for First Nations under the *Indian Act*. The transfer of title to these assets did not occur because authorizations originally granted by the federal Minister of Indigenous Services Canada for the construction and operation of these assets could not be transferred without the consent of the Minister and the relevant First Nations or, in several cases, because the authorizations had either expired or had never been properly issued.

The portion of Ontario Hydro's former electricity transmission business, primarily comprised of transmission lines, continues to be held by the Ontario Electricity Financial Corporation (OEFC). Under the terms of the transfer orders, Hydro One is required to manage these assets until it has obtained all consents necessary to complete the transfer of title from the OEFC to Hydro One. Hydro One is seeking to obtain from the relevant First Nations, the consents necessary to complete the transfer of title to these assets. Hydro One makes annual payments associated with historical grants and assets that did not transfer and will remain obliged to do so until it negotiates a new agreement that releases OEFC from past obligations and liabilities.

In 2025, the increase in First Nations rights payments from $3.6M to $5.8M was driven by a higher number of agreements being completed, as well as renewals that were finalized to meet existing legal obligations. First Nations rights payments in 2026 and 2027 are forecasted to be lower than 2025 actuals. The First Nations rights payments for 2028 are

budgeted to be $5.5M. This amount is approximately $0.4M, or 8%, higher than 2027 forecast, while being $0.3M lower than 2025 actuals. Variations in annual expenditures reflect payments required under existing legal obligations, including agreement renewals undertaken in accordance with those obligations, and the timing of new agreements reaching conclusion that give rise to additional payment obligations. As the timing of these activities varies from year to year, associated expenditures may fluctuate accordingly.

3.0 DISTRIBUTION TAXES

In respect of the Distribution business, Table 4 summarizes property tax and rights payments over the historical, bridge, and test years.

Table 4 - Taxes - Distribution ($M) [3]

Description	Historical				Bridge	Test
	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
Property Tax	5.5	5.8	5.8	6.3	6.5	6.9
Rights Payment	0.6	0.1	0.6	0.4	0.5	0.5
Total	**6.2**	**5.8**	**6.4**	**6.7**	**7.0**	**7.5**

The 2028 Test Year expenditure for Distribution Property Tax and Rights Payments is $7.5M, a $1.3M increase over 2023 actuals, and a $1.1M increase over the average of the last rate period (2023-2027).

3.1 DISTRIBUTION PROPERTY TAX

Hydro One is responsible for the payment of property taxes similar to every other landowner within the province of Ontario. Property taxes for Hydro One are regulated under the *Electricity Act, 1998*, the *Municipal Act, 2001*, and the *Assessment Act*. Property taxes are paid on company-owned distribution lands and buildings including service centre sites, distribution transformer stations, and distribution lines. Hydro One Networks Inc. makes property tax payments to 385 municipalities each year.

[3] Figures presented in the tables may not sum to the totals shown due to rounding.

The total assessed property values are assigned by the MPAC and are updated using the same schedule as the rest of the province. Except for distribution transformer stations (described below), all distribution properties owned by Hydro One Networks Inc. are assessed using a CVA method – the valuation method used for other property owners within the province. As described above, the CVA method is currently based on a January 1, 2016 valuation date.

As described above in Section 2.1, property tax Notices of Assessment are received and reviewed by Hydro One for accurate valuation and tax classification each year. Any incorrect classes and overvaluations are appealed through MPAC or the Assessment Review Board.

Despite currently stable CVAs, Hydro One's property taxes are subject to increases due to annual tax rate increases by municipalities and the regions in which they are located.

Similar to transmission stations, property taxes for distribution transformer stations are the product of multiple taxes. Distribution transformer station buildings are assessed at a statutory rate of $86.11 per square metre, per the *Assessment Act*. Distribution transformer stations are subject to property proxy taxes, payable to the Minister of Finance under Ontario Regulation 423/11 of the *Electricity Act, 1998*. Property proxy taxes are calculated for each distribution transformer station building owned by Hydro One Networks Inc. and are included in the property tax amount. The lands containing the distribution stations are assessed using the CVA method - the valuation method used for other property owners within the province. Other Hydro One property (i.e., real property other than distribution lines and distribution stations) is assessed using only the CVA method. The annual distribution property taxes are presented in Table 5 below.

Table 5 - Property Tax Expense - Distribution ($M)

Description	Historical				Bridge	Test
	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
Property Tax	5.5	5.8	5.8	6.3	6.5	6.9

As noted above, the annual Distribution property taxes for the years 2023 to 2028 range from $5.5M to $6.9M. The 2028 Test Year expenditure for Distribution Property Tax is $6.9M, a $1.4M increase over 2023 actuals, and a $0.9M increase over the average of the last rate period (2023-2027).

From 2023-2025, Distribution property taxes remained roughly constant. Forecasted property taxes increase in the 2026 to 2028 period due to annual rate increases by municipalities and the regions in which they are located. Just by way of example of this type of increase, in Kingston, Ontario, Hydro One's property taxes at Elginbury DS, increased by 7% from 2023-2025.

3.2 DISTRIBUTION RIGHTS PAYMENTS

Through agreements or permits, Hydro One Distribution line facilities cross and/or occupy properties owned by railway companies (e.g. Canadian Pacific and Kansas City Southern (CPKC), Canadian National) and/or governmental bodies (e.g., Ministry of Natural Resources, Metrolinx). Per the terms of the agreements, Hydro One Networks Inc. pays annual rights fees to the railway companies and the government entities in this regard.

Table 6 - Rights Payments - Distribution ($M) [4]

Description	Historical				Bridge	Test
	2023 Actual	2024 Actual	2025 Actual	2026 Forecast	2027 Forecast	2028 Forecast
Right Payment associated with non-First Nations	0.6	0.0*	0.4	0.4	0.4	0.4
Right Payment associated with First Nations	0.1	0.1	0.2	0.1	0.1	0.1
Rights Payments Total	**0.6**	**0.1**	**0.6**	**0.4**	**0.5**	**0.5**

** Value is less than $50k.*

[4] Figures presented in the tables may not sum to the totals shown due to rounding.

The 2028 Test Year expenditure for Distribution Rights Payments is $0.5M, a $0.1M increase over the average of the last rate period (2023-2027).

Rights payments associated with non-First Nations are largely consistent across the 2023-2027 rate period, with the decrease in 2024 reflecting a change in accounting method rather than a change in payments. Hydro One expects some increased costs in the 2025 to 2028 period as negotiations with government bodies and railway companies and reviews within the agreements are triggered. This expectation is mainly due to increases in land values.

From 2023-2027, fluctuations in First Nations rights payments are driven by settlements for historical obligations, updated agreements, changes in First Nation land occupancy, and periodic rent review and renewal.

ONE-TIME REGULATORY COSTS

1.0 OVERVIEW

The Exhibit includes a description of Hydro One's one-time regulatory costs to prepare this Application. One-time regulatory costs are recovered in the year in which they are incurred, not amortized over the application term.[1]

Ongoing regulatory costs are included as common corporate OM&A costs. See Appendix 2-JB OM&A Cost Drivers for Transmission, Distribution and HOSSM for further details. One-time regulatory costs for HOSSM are immaterial and are derived from the corporate cost allocation.

2.0 TYPES OF APPLICATION COSTS

Costs associated with the preparation and litigation of this Application include:

- **Legal costs:** External legal counsel was retained to assist with the development and litigation of the Application.

- **External consultant costs**:
  - *Consultants:* External consultants were retained to assist with the development and litigation of the Application.
  - *Independent Expert Studies*: Independent experts developed studies to support the Application and to satisfy the terms of settlement n Hydro One's 2023-2027 Custom IR Application (EB-2021-0110). This includes responding to questions about their studies and provide expert testimony during the litigation of the Application. A list of studies submitted as part of this Application is included at Exhibit A-02-04.

[1] Per Chapter 2 Filing Requirements, section 2.4.3.4

- **Intervenor costs**: These amounts reflect intervenor costs anticipated to be incurred over the course of the proceeding. Forecast amounts are expected to be incurred in 2028.

- **OEB section 30 costs**: These amounts reflect OEB processing costs such as hearing costs anticipated to be incurred over the course of the proceeding. Forecast amounts are expected to be incurred in 2028.

- **Expert witness costs**: Amounts for expert witnesses to respond to interrogatories and undertakings and to provide expert testimony during the proceeding are included as part of the "Consultant" costs.

3.0 DIRECT APPLICATION COSTS – TRANSMISSION, DISTRIBUTION & HOSSM

Tables 1 and 2 include actual costs from 2023 to 2025 and forecast costs through to the end of 2026, the 2027 bridge and 2028 test years associated with this Application for Transmission and Distribution respectively. Costs are also delineated in Attachment 1 to this Exhibit: Appendix 2-M – Regulatory Cost Schedule.

Table 1 - Direct Application Cost - Transmission ($M)

Description	2023	2024	2025	2026	2027	2028
Expert Witness Costs	-	-	-	-	-	-
Legal	-	0.2	0.7	0.8	1.0	-
Consultants	-	0.3	0.8	0.7	0.5	0.2
Studies	-	0.2	1.5	1.9	0.2	-
Intervenors	-	-	-	-	-	0.8
OEB Section 30 Costs (application-related)	-	-	-	-	-	0.5
Total	**0.0**	**0.8**	**3.0**	**3.4**	**1.7**	**1.6**

Hydro One Transmission's forecast one-time regulatory costs are generally consistent with those reported for recently completed rebasing applications by other large Ontario utilities.

Table 2 - Direct Application Cost - Distribution ($M)

Description	2023	2024	2025	2026	2027	2028
Expert Witness Costs	-	-	-	-	-	-
Legal	-	0.2	0.7	0.7	0.9	-
Consultants	-	0.3	0.7	0.6	0.4	0.1
Studies	-	0.2	1.4	1.6	0.2	-
Intervenors	-	-	-	-	-	0.4
OEB Section 30 Costs (application-related)	-	-	-	-	-	0.2
Total	**0.0**	**0.7**	**2.7**	**3.0**	**1.5**	**0.7**

Hydro One Distribution's forecast one-time regulatory costs are generally consistent with those reported for recently completed rebasing applications by other large Ontario utilities.

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CHAPTER 2 APPENDIX 2-M: REGULATORY COST SCHEDULE

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ONE TIME COSTS

Hydro One is not seeking recovery of any one-time costs, as described in section 2.8.7 of the Filing Requirements for Electricity Transmission Applications and section 2.4.3.4 of the Filing Requirements for Electricity Distributors.

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CHARITABLE AND POLITICAL DONATIONS

Hydro One confirms that neither charitable donations nor political donations have been included in this Application for recovery. Any charitable donations made by Hydro One are allocated to its non-regulated accounting segment, not Hydro One Transmission nor Hydro One Distribution.

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Z-FACTOR CLAIMS

Hydro One Networks (Transmission and Distribution) and HOSSM are not requesting a z-factor claim in this Application. Materiality thresholds for Z-factor claims are discussed in Exhibit A-04-01.

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