Hydro One Networks Inc.
483 Bay Street
7th Floor South Tower
Toronto, Ontario M5G 2P5
HydroOne.com

Elise Andrey
Director, Applications Delivery
C 416.770.6305
Elise.Andrey@HydroOne.com

BY EMAIL

November 27, 2026

Mr. Ritchie Murray
Registrar
Ontario Energy Board
Suite 2700, 2300 Yonge Street
P.O. Box 2319
Toronto, ON M4P 1E4

Dear Mr. Murray,

EB-2021-0110 – Hydro One Networks Inc.'s Settlement Commitments

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022.

Under the terms of the Settlement Agreement, Hydro One agreed to prepare and publish reports listed in Appendix A below. Accordingly, these materials for 2025 have been published on Hydro One's website: Transmission Rate Applications, Distribution Rate Applications.

Should you have any questions, please contact Michelle Reesor via email at Michelle.Reesor@hydroone.com.

Sincerely,

Elise Andrey

Appendix A

Section	Description	Settlement Reference[1]
1.0	Scorecards	
1.1	Fiscal 2025 - Hydro One Networks Distribution Scorecard and Management Discussion and Analysis	Part A.2
1.2	Fiscal 2025 - Hydro One Networks Electricity Transmitter Scorecard and Management Discussion and Analysis	Part A.2
2.0	Capital Performance Reports	
2.1	2025 Transmission Capital Performance Report	Part A.1
2.2	2025 Distribution Capital Performance Report	Part A.1
2.3	2025 General Plant Capital Performance Report	Part A.1
3.0	Other Reporting	
3.1	DERs Connected to Hydro One's Distribution System (per undertaking JT-3.22)	Part A.3
3.2	Residential Energy Storage Performance Data	Part E.3
3.3	Grid Scale Energy Storage Performance Data	Part E.3

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.327-334 (Settlement Proposal, Appendix A, p. 106-113)

Section 1.1

Fiscal 2025 – Hydro One Networks Distribution OEB Scorecard and Management Discussion and Analysis

Fiscal 2025 – Hydro One Networks Distribution OEB Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Distribution OEB Scorecard MD&A - General Overview

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission rebasing application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The Hydro One 2025 Distribution Scorecard discussion is set out below.

Customer Satisfaction

Hydro One collects customer satisfaction data through customer perception studies conducted by independent expert research firms.

- **Small Business and Residential Satisfaction**

  The Small Business and Residential ("SB&R") customer satisfaction survey is conducted every month among randomly selected customers who may or may not have interacted with Hydro One recently. The customer satisfaction measure captures SB&R customers' overall satisfaction with the service they receive from Hydro One. The survey includes a range of questions regarding customers' experience and satisfaction with their electricity service, allowing Hydro One to monitor how well the company meets customers' expectations and delivers on critical success factors.

  The SB&R Satisfaction was 88% in 2025, which met the target of 87%.

[1] EB-2021-0110, Settlement Agreement, Appendix A

- **Handling of Unplanned Outages Satisfaction**

  This measure captures customer satisfaction with Hydro One's handling of unplanned outages. The data is collected through a transactional online survey that is sent to customers who reside in an area affected by an unplanned outage, after the outage has occurred. An outage satisfaction index is calculated as the simple average of three components: (1) satisfaction with communication, (2) satisfaction with time it took to restore power and (3) satisfaction with accuracy of Estimated Time of Restoration (ETR).

  The Handling of Unplanned Outages Satisfaction was 80% in 2025, which did not meet the target of 82%. This is primarily attributable to satisfaction with the amount of time it took to restore power and satisfaction with ETR accuracy.

- **Call Centre Customer Satisfaction**

  This measure captures customer satisfaction with services provided by Hydro One's call centre, which is often the first point of contact Hydro One has with a customer when they have a question or an issue that needs to be resolved. Customer satisfaction after the call is a strong indication of whether a customer inquiry has been addressed appropriately. This metric demonstrates whether services are provided in a manner that is responsive to customer needs. The call centre customer satisfaction survey occurs shortly after the phone call, which allows the call centre to capture timely and accurate information and to address any areas for improvement.

  The Call Centre Customer Satisfaction was 84% in 2025, which did not meet the target of 86%. This was primarily attributable to outage communications, account and billing calls, and a higher share of complex inquiries that required more effort to resolve as digital and self-service channels shifted routine transactions away from the call centre.

- **myAccount Customer Satisfaction**

  This measure captures customer satisfaction with services delivered by Hydro One's myAccount web portal. The myAccount portal allows customers to view their bills, analyze their electricity usage and request several services online, in a convenient and efficient manner.

  The myAccount Customer Satisfaction was 66% in 2025, which did not meet the target of 68%. This was primarily attributable to two isolated technical issues experienced where corrective actions have been implemented.

Cost Control

- **Pole Replacement - Gross Cost per Unit**

  The Pole Replacement Gross Cost per Unit is defined as the total pole replacement costs, divided by the total number of poles replaced.

  The gross cost per pole replacement was $18,191 in 2025, which did not meet the target. This result reflects increased unit costs driven by the ramp-down and deferral of portions of the replacement program to higher-priority safety and reliability work. Lower replacement volumes, while design, permitting, and other preparatory activities continued, resulted in fixed and trailing costs being spread across fewer completed units. The use of contractors also contributed to higher labour expenses.

- **Vegetation Management – Gross Defect Correction Cost per km**

  The Vegetation Management Gross Defect Correction Cost per kilometer is measured as the total cost of the Optimal Cycle Protocol vegetation management program divided by the number of kilometers of line cleared.

  The Vegetation Management unit cost was $8,580 in 2025, which did not meet the target. This result is due primarily to increased defect densities and more complex vegetation conditions than anticipated. Reduced brush management in prior years resulted in greater vegetation growth requiring increased effort per kilometer. In addition, a greater proportion of work required specialized resources to safely manage vegetation within proximity limits, resulting in higher labour expenses.

- **Station Refurbishment – Gross Cost per MVA**

  The Station Refurbishment – Gross Cost per Mega Volt Amp (“MVA”) is defined as the total cost of station refurbishments divided by the total number of refurbished MVAs. Every station refurbishment project has a unique scope of work resulting in variation of the total cost for each investment. The cost per MVA measure only considers projects which have a station MVA of less than 10 MVA.

  The Station Refurbishment cost was $917,979 per MVA in 2025, which did not meet the target. This result is due to the lower number of completed projects, dependence on higher-cost solutions due to the unavailability of lower-cost padmount distribution stations, and increased material and labour expenses.

- **Operations, Maintenance and Administration (OM&A) dollars per customer**

  OM&A dollars per customer is defined as total OM&A divided by the number of customers.

  The OM&A per customer was $419 in 2025, which met the target of $469.

- **Operations, Maintenance and Administration (OM&A) dollars per kilometer of line**

  OM&A dollars per kilometer of line is defined as total OM&A divided by the total number of kilometers of distribution lines.

  The OM&A per kilometer of line was $5,058 per km in 2025, which met the target of $5,393.

System Reliability

The System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI) are tracked for a number of scenarios.

- **SAIDI for Equipment-Caused Interruptions**

  SAIDI for Equipment-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for equipment-caused interruptions. This metric tracks the SAIDI impact and outcome caused by distribution equipment failures on an annual basis.

  The SAIDI for Equipment Caused Interruptions was 1.9 hours in 2025, which did not meet the target of 1.5 hours. This was primarily attributed to a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIDI for Vegetation-Caused Interruptions**

  SAIDI for Vegetation-Caused Interruptions is defined as the average number of hours that power to a customer is interrupted for vegetation-caused interruptions. This metric tracks the SAIDI impact and outcome for vegetation-caused interruptions on an annual basis.

Visibility to the vegetation-caused interruptions allows focus to be placed on those areas with less-than-optimal performance. Ultimately, one of the expected outcomes and customer benefits of the vegetation management program is a reduction in vegetation-caused outages. This metric is a lagging indicator of the outcomes of the vegetation management program.

The Vegetation Caused SAIDI was 2.1 hours in 2025, which did not meet the target of 1.7 hours. This was primarily attributed to a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year and an increased tree/defect density.

- **SAIDI – Rural Duration**

  SAIDI – Rural Duration is defined as the total number of hours of interruption for rural customers divided by the total number of rural customers served. All rural planned and unplanned interruptions of one minute or more (excluding loss of supply and force majeure events) are used to calculate this measure.

  The SAIDI – Rural Duration was 10.0 hours in 2025, which did not meet the target. This was primarily attributed to tree contacts and equipment failures, coupled with a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIFI - Rural Frequency of Outages**

  SAIFI – Rural Frequency of Outages is defined as the total number of rural customer interruptions divided by the total number of rural customers served. The SAIFI – Rural metric tracks the average interruption frequency for the rural areas only. All rural planned and unplanned interruptions of one minute or more (excluding loss of supply and force majeure events) are used to calculate this measure.

  The SAIFI - Rural Frequency of Outages had a frequency of 3.3 outages per rural customer in 2025, which did not meet the target. This was primarily attributed to tree contacts and equipment failures, coupled with a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIDI – Urban Duration**

  SAIDI – Urban Duration of outages is defined as the total customer hours of interruption for urban customers divided by the total number

of urban customers served.

The SAIDI - Urban Duration was 2.9 hours in 2025, which did not meet the target of 2.8 hours. This was primarily attributed to equipment failures and a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **SAIFI - Urban Frequency of Outages**

  SAIFI – Urban Frequency of Outages is defined as the total number of interruptions for urban customers divided by the total number of urban customers served. The SAIFI – Urban metric tracks the average interruption frequency for the urban areas only.

  The SAIFI - Urban Frequency of Outages had a frequency of 1.6 outages per urban customer in 2025, which did not meet the target of 1.5. This was primarily attributed to equipment failures and a high number of storm days in 2025, including 47 storm days compared to the 10-year historical average of 36 storm days per year.

- **Large Customer Interruption Frequency**

  Large Customer Interruptions Frequency is defined as the total number of interruptions for Large Distribution Customer Accounts (“LDAs”) divided by the total number of large distribution accounts served. This metric tracks the sustained interruption frequency to all LDA customers connected to Hydro One.

  The Large Customer Interruption Frequency had a frequency of 1.2 interruptions per large distribution customer account in 2025, which met the target of 1.6 interruptions per large distribution customer account.

Note to Readers of Fiscal 2025 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to expected outcomes and customer benefits of the vegetation management program, and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include legislative or regulatory developments, government policy and program developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Distribution OEB Scorecard

Performance Outcomes	Performance Categories	Measures	2020	2021	2022	2023	2024	2025	JRAP Target 2025
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	87%	89%	87%	87%	88%	88%	87%
		Handling of Unplanned Outages Satisfaction (%)	77%	78%	78%	78%	79%	80%	82%
		Call Centre Customer Satisfaction (%)	86%	86%	86%	84%	86%	84%	86%
		My Account Customer Satisfaction (%)	52%	60%	67%	68%	72%	66%	68%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in ($)	$10,624	$11,158	$13,133	$15,216	$19,477	$18,191	$11,032
		Vegetation Management - Gross Defect Correction (OCP) Cost per km ($)	$5,670	$4,019	$5,070	$6,996	$8,026	$8,580	$3,980
		Station Refurbishment - Gross Cost Per MVA ($)	$315,000	$356,899	$655,244	No projects in service	$818,524	$917,979	$421,000
		OM&A dollars per customer ($)	$410	$409	$461	$459	$474	$419	$469
		OM&A dollars per km of line ($)	$4,622	$4,779	$5,441	$5,469	$5,709	$5,058	$5,393
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)	2.3	2.1	2.6	2.0	1.7	1.9	1.5
		SAIDI for Vegetation Caused Interruptions (hrs)	3.1	2.7	2.5	1.7	2.0	2.1	1.7
		SAIDI - Rural - duration (hrs)	8.3	7.5	8.0	8.8	9.2	10.0	4.7
		SAIFI - Rural - frequency of outages	2.8	2.6	2.8	3.2	3.1	3.3	2.0
		SAIDI - Urban - duration (hrs)	2.7	2.8	2.8	3.5	3.1	2.9	2.8
		SAIFI - Urban - frequency of outages	1.3	1.4	1.3	1.6	1.5	1.6	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	1.6	1.3	1.5	1.7	1.3	1.2	1.6

Section 1.2

Fiscal 2025 – Hydro One Networks Electricity Transmitter Scorecard and Management Discussion and Analysis

Fiscal 2025 Hydro One Networks Electricity Transmitter Scorecard, Management Discussion and Analysis ("Scorecard MD&A")

Hydro One Networks Electricity Transmitter Scorecard MD&A - General Overview

In Hydro One Networks Inc.'s (Hydro One) application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Agreement) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, Hydro One agreed as follows:

> *For each of Distribution and Transmission, Hydro One will prepare a scorecard. The scorecards will be prepared subject to the following conditions: i) they will be prepared annually, no earlier than September 30th each year to align with OEB RRR scorecards; ii) upon completion they will be published on Hydro One's website; iii) they will be prepared for the purposes of Hydro One's next Distribution and Transmission rebasing application and will not form part of Hydro One's annual update applications during the 2023-2027 Custom IR term; iv) they will include discussion sections similar to the OEB Distribution RRR Scorecard; and v) they may be redacted if necessary.*[1]

The 2025 Hydro One Transmission Scorecard discussion is set out below.

Service Quality

- **Customer Delivery Point Performance - Standard Outliers as Percent of Total Delivery Points**

  The Customer Delivery Point Performance is a service quality metric that is measured as the number of standard performance outliers (using standards set by the OEB) as a percentage of the total number of Hydro One delivery points. Customer Delivery Point Performance Standards (CDPPS) were established by the OEB to ensure acceptable transmission reliability experienced at transmission customer delivery points. The group outlier standard defines a delivery point as an outlier if its performance is over the thresholds based on its station load size. The individual outlier standard defines a delivery point as an outlier if its recent two year's performance is worse than its historical performance. The percentage of outliers to total number of delivery points is measured annually.

[1] EB-2021-0110, Settlement Agreement, Appendix A

The Standard Outliers as a Percent of Total Delivery Points was 9.3% in 2025, which met the target of 10.6%.Customer Satisfaction

- **Overall Customer Satisfaction**

  This measure reflects the overall satisfaction levels among customers within the three major transmission-connected segments (Transmission End Users, Local Distribution Companies (LDCs) and Transmission-Connected Generators).

  The Overall Customer Satisfaction was 79% in 2025, which did not meet the target of 88%. The result was primarily attributed to major weather events.

- **Satisfaction With Outage Planning Procedures**

  This measure reflects the satisfaction with planned outage management among customers within the three major transmission-connected segments (Transmission End Users, LDCs and Transmission-Connected Generators).

  Satisfaction with Outage Planning Procedures was 84% in 2025, which did not meet the target of 85%. The result was primarily due to workload growth driven by an increase in development activity (new lines and stations) that raised the complexity of prioritization of outage planning and the potential for greater customer impact.

Safety

- **Recordable Injury # of recordable injuries/illnesses per 200,000 hours worked**

  The number of recordable injuries/illnesses per 200,000 hours worked measures the work-related injuries or illnesses per 200,000 hours worked which result in: restricted work, lost time, loss of consciousness, medical attention beyond first aid, death, or any other significant work-related injury or illness diagnosed by a physician or other healthcare professional and are confirmed by a Hydro One Occupational Health Nurse. This measure only applies to employees of Hydro One and excludes contractors and the general public.

  The Recordable Injury rate was 0.68 in 2025, which met the target of 0.9.

System Reliability

- **T-SAIFI-S (Average Number of Sustained interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Sustained is measured as the total number of unplanned sustained interruptions (1 minute or longer) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Sustained was 0.46 in 2025, which met the target of 0.54.

- **T-SAIFI-M (Average Number of Momentary interruptions per Delivery Point)**

  Transmission System Average Interruption Frequency Index – Momentary is measured as the total number of unplanned momentary interruptions (less than 1 minute) that customers experienced per Delivery Point in a year. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Frequency Index – Momentary was 0.26 in 2025, which met the target of 0.41.

- **T-SAIDI (Average minutes of interruptions per Delivery Point)**

  Transmission System Average Interruption Duration Index is measured as the total number of minutes of unplanned interruptions that customers experienced per Delivery Point in a year. The measure is presented as interruption minutes per delivery point per year. Only sustained (1 minute and longer as per the Canadian Electricity Association (CEA) industry standard) interruptions contribute to this measure. The measure includes the impact of all interruptions caused by forced outages and excludes events with excessive impact or events that strongly skew the historical trend of the measure.

  The Transmission System Average Interruption Duration Index was 18.5 in 2025, which met the target of 31.3.

- **System Unavailability (%)**

  System Unavailability measures the unavailability of transmission lines and major transmission station equipment, due to direct automatic or forced manual outages caused by factors such as defective equipment, adverse weather, adverse environment, foreign interference and human element. While equipment unavailability doesn't necessarily lead to interruptions due to redundancy on Hydro One's transmission system, it is a leading indicator of future reliability erosion.

  Major station equipment includes transmission lines, high voltage cables, breakers, transformers, shunt capacitor banks, shunt reactors, series capacitor banks and static VAR compensators. This metric does not take into consideration the subordinate outages of healthy transmission equipment being removed out of service because of the outage of some other equipment.

  The System Unavailability was 0.63% in 2025, which did not meet the target of 0.60%. This result was primarily due to large contributions to this metric by transformers awaiting replacement, capacitors and capacitor breakers awaiting repairs and repair of switches.

- **Unsupplied Energy (minutes)**

  Unsupplied Energy is the total energy not supplied to customers during the year, measured in system minutes, due to unplanned interruptions to all delivery points. This measure is normalized against the system peak to allow comparison with the performance of different sized utilities.

  The Unsupplied Energy was 5.7 minutes in 2025, which met the target of 8.6 minutes.

Asset and Project Management

- **Transmission System Plan Implementation Progress (%)**

  The Transmission System Plan Implementation Progress is measured as the total actual in-year sustainment, development, and operating expenditures for in-service additions over the total internal company scorecard budget expenditures for in-service additions, including any OEB carry-forward variance.

  In-service capital additions are tracked and reported in a manner consistent with the regulatory requirements of the transmission business and reported as a percentage value relative to the transmission plan.

  The Transmission System Plan Implementation Progress was 91% in 2025, which did not meet the target of 100%. The result is primarily driven by the timing of major project completions and changes in the nature of work undertaken during the current rate period.

- **CapEx as % of OEB Approved Plan**

  Capex as a percentage of budget is measured as the total actual capital expenditures over the total amount budgeted (planned) capital expenditures in a year. This measure reflects the progress of Hydro One's capital expenditures towards the approved plan.

  The CapEx as a % of Budget was 109% in 2025, which met the target of 100% with increased levels of mandatory system development work driven by external requirements, customer requests, and growth.

- **Operations, Maintenance and Administration (OM&A) Program Accomplishment (composite index)**

  The Transmission OM&A Program Accomplishment (composite index) measure compares the weighted actual in-year accomplishment for significant Tx OM&A Programs against the weighted budget. There are eight programs monitored for this measure including: 1) forestry line clearing; 2) brush control; 3) PCB testing and retro fill; and station preventive maintenance programs which include 4) power equipment, 5) ancillary equipment, 6) protection and control, 7) telecom and 8) infrastructure.

  The Transmission OM&A Program Accomplishment composite index was 97 in 2025, which did not meet the target of 100. The results

are primarily due to lower work program expenditures in the PCB Testing and Retrofill programs primarily attributable to lower number of units accomplished with limited candidate availability.

- **Transmission Capital Accomplishment Index (TCAI) - (%)**

  The TCAI compares the weighted actual in-year accomplishment for significant transmission system renewal capital investments against the weighted budget. The investments covered by this metric represent the major assets associated with station centric and lines refurbishment projects being transformers, circuit breakers, protections and circuit kilometers of transmission line, as well as five programs including insulator replacement, wood pole replacement, shield wire replacement, tower foundations and steel structure coating.

  The Transmission Capital Accomplishment Index was 112% in 2025, which met the target of 100%.

COST CONTROL

- **Total OM&A and Capital per Gross Fixed Asset Value (%)**

  The Total OM&A and Capital per Gross Fixed Asset Value is measured as the total capital and OM&A spend over the total gross book value of in-service assets. This measure demonstrates transmission cost effectiveness.

  The Total OM&A and Capital per Gross Fixed Asset Value was 7.6% in 2025, which did not meet the target of 7.0%.

- **OM&A per Gross Fixed Asset Value (%)**

  OM&A per Gross Fixed Asset Value is measured as the total OM&A over the gross book value of fixed assets. The measure demonstrates transmission cost effectiveness.

  The OM&A per Gross Fixed Asset Value was 1.8% in 2025, which met the target of 1.8%.

- **Line Clearing Cost per Kilometer ($/km)**

  The Line Clearing Cost per Kilometer is measured as the total line clearing costs over the total number of kilometers of transmission line. This measure shows the cost associated with line clearing activities completed in the year, per kilometer of line.

  The Line Clearing Cost per Kilometer was $2,896 in 2025, which met the target of $2,925.

- **Brush Control Cost per Hectare ($/Ha)**

  The Brush Control Cost per Hectare is measured as the total cost of brush control completed in the year, per hectare of brush.

  The Brush Control Cost per Hectare was $2,678 in 2025, which did not meet the target of $1,711. The result is primarily attributable to project requirement changes requiring inclusion of urban and helicopter support, higher fleet and labour costs along with an increase in temporary work headquarter costs.

Customer Impact Assessment on Renewable Generation

- **% On-time completion of Customer Impact Assessments on Renewable Generation**

  For new Transmission-connected renewable generation projects, Hydro One was required under the O. Reg. 326/09 to complete a customer impact assessment (CIA) for renewables within 150 days. The % of on-time completion of renewables CIAs is measured as the total number of renewables CIAs completed within the required timeline over the total number of renewables CIAs completed in the year. This regulation was rescinded in 2021.

  In 2025, no requests for transmission-connected renewable generation were received. As a result, no Customer Impact Assessments were required or conducted. Accordingly, performance for this metric is reported as “No CIAs Required in 2025”.

Regional Infrastructure Planning & Long-Term Energy Plan (LTEP) Right-Sizing

- **Regional Infrastructure Planning progress - Deliverables Met (%)**

  Regional Infrastructure Planning Progress – Deliverables Met measures progress in meeting the deliverables of the regional infrastructure planning process, including meeting the Transmission System Code ("TSC") prescribed timelines and delivering the required products. The number of deliverables will vary in a given year. Deliverables include plans, reports and Local Distribution Companies (LDC) status update letters. Deliverables Met is measured as the number of correct deliverables that meet the TSC prescribed timelines over the total number of deliverables.

  The Regional Infrastructure Planning Progress – Deliverables was 100%, which met the target in 2025.

- **End-of-Life Right-Sizing Assessment Expectation**

  This qualitative measure gauges Hydro One's performance in meeting the expectation that no more than two (2) assessment opportunities for right-sizing the replacement of end-of-life equipment to facilitate future growth are missed during the year, for all regions assessed in the year as part of the Regional Planning Process. The number of regions assessed may vary in each year. Measure Calculation: N/A as this is a qualitative measure – either Met or Not Met

  The End-of-Life Right Sizing Assessment Expectation met the target in 2025.

Financial Ratios

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  Liquidity: Current Ratio measures the ratio of current assets to current liabilities. Current assets are defined as cash or other assets to be converted to cash within the year. Current liabilities are defined as short-term debts or financial obligations that will become due within the year.

  The Liquidity: Current Ratio was 0.25 in 2025.

- **Leverage: Total Debt to Equity Ratio**

  The Total Debt to Equity Ratio is measured as the total short-term and long-term debt over the total equity. This measure reflects Hydro One's financial leverage and serves to identify the ability to finance assets and fulfill obligations to creditors, while remaining within the OEB-mandated 60% to 40% debt-to-equity structure (a ratio of 1.5).

  The Leverage: Total Debt to Equity Ratio was 1.72 in 2025.

- **Profitability: Regulatory Return on Equity**

  Achieved Regulatory Return on Equity (ROE) measures the return earned on the equity component that is embedded in the transmitter's base rates. Hydro One's Transmission Business deemed regulatory return on equity (ROE) for 2025 is 9.36%, as approved by the OEB.

  The Profitability: Regulated Return on Equity was 12.72% in 2025. The 2025 achieved ROE was higher than deemed primarily due to higher demand driven by external factors including weather-related variability as compared to the load forecast embedded in rates, and other factors including timing of in-service additions.

Note to Readers of Fiscal 2025 Scorecard MD&A

The information provided by transmitters on their future performance (or what can be construed as forward-looking information) may be subject to several risks, uncertainties and other factors that may cause actual events, conditions or results to differ materially from historical results or those contemplated by the distributor regarding their future performance.

Words such as “expect,” “anticipate,” “intend,” “attempt,” “may,” “plan,” “will”, “can”, “believe,” “seek,” “estimate,” and variations of such words and similar expressions are intended to identify such forward-looking statements and information. Such statements include, but are not limited to, references to financial measurements and their implications, and targets. These statements are not guarantees of future performance and involve assumptions and risks and uncertainties that are difficult to predict. Some of the factors that could cause such differences include legislative or regulatory developments, government policy and program developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management’s best judgment on the reporting date of the performance scorecard and could be markedly different in the future. We do not intend, and we disclaim any obligation to update any forward-looking statements, except as required by law.

Hydro One Networks Electricity Transmitter Scorecard

Performance Outcomes	Performance Categories	Measures		2020	2021	2022	2023	2024	2025	JRAP Target 2025
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs (%)		11.4%	8.3%	9.3%	10.9%	13.6%	9.3%	10.6%
	Customer Satisfaction	Overall Customer Satisfaction (%)		83%	92%	88%	88%	85%	79%	88%
		Satisfaction with Outage Planning Procedures (%)		71%	82%	78%	72%	88%	84%	85%
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		0.87	0.74	0.62	0.56	0.55	0.68	0.90
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.50	0.49	0.64	0.54	0.52	0.46	0.54
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.40	0.42	0.43	0.46	0.44	0.26	0.41
		T-SAIDI (Ave. minutes of interruptions per Deliver Point)		61.3	21.0	61.0	25.9	23.7	18.5	31.3
		System Unavailability (%)		0.83%	0.67%	0.76%	0.52%	0.50%	0.63%	0.60%
		Unsupplied energy (minutes)		8.0	7.1	13.3	6.4	8.2	5.7	8.6
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		101%	99%	101%	97%	95%	91%	100%
		CapEx as % of Budget (%)		104%	112%	114%	97%	114%	109%	100%
		OM&A Program Accomplishment (composite index)		93%	105%	96%	109%	102%	97%	100%
		Transmission Capital Accomplishment Index (%)		101%	99%	80%	91%	95%	112%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		7.9%	8.3%	7.6%	8.6%	8.5%	7.6%	7.0%
		OM&A per Gross Fixed Asset Value (%)		2.1%	2.0%	2.2%	2.4%	2.0%	1.8%	1.8%
		Line Clearing Cost per kilometer ($/km)		$3,368	$2,211	$2,140	$2,210	$2,426	$2,896	$2,925
		Brush Control Cost per Hectare ($/Ha)		$1,538	$1,807	$2,003	$1,916	$2,402	$2,678	$1,711
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments (CIAs)		100%	100%	100%	None requested	None requested	None requested	100%
	Regional Infrastructure Planning & Long-Term Energy Plan Right-Sizing	Regional Infrastructure Planning progress - Deliverables met (%)		100%	95%	100%	100%	100%	100%	100%
		End-of-Life Right-Sizing Assessment Expectation		Met	Met	Met	Met	Met	Met	Met
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.28	0.27	0.23	0.21	0.21	0.25	N/A
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.50	1.40	1.37	1.48	1.65	1.72	N/A
		Profitability: Regulatory Return on Equity	Deemed	8.52%	8.52%	8.52%	9.36%	9.36%	9.36%	N/A
			Achieved RROE %	9.29%	9.30%	9.92%	10.80%	10.96%	12.72%	N/A

Section 2.1

2025 Transmission Capital Performance Report

SECTION 2.9 – ATTACHMENT 5 – TRANSMISSION CAPITAL PERFORMANCE REPORT – 2025

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report (CPR) provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2025 in relation to the overall transmission capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISAs) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISAs.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (Forecast). This was the first time Hydro One allocated the impact of the Settlement Proposal at the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY

Table 1 below presents a breakdown of the actual 2025 transmission capital expenditures and ISAs by OEB investment category and compares them to the OEB-approved values. The primary focus of this report is on the Transmission System Access, System Renewal,

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

and System Service categories. The Transmission General Plant category is discussed in the General Plant Capital Performance Report.

Table 1 - 2025 Transmission Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2025			In-Service Additions – 2025		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	63.0	148.9	85.9	63.9	99.2	35.3
System Renewal	1,172.4	1,103.7	-68.7	1,334.2	1,168.1	-166.1
System Service	90.3	141.0	50.7	172.3	77.3	-94.9
General Plant	111.8	111.0	-0.8	125.7	134.6	8.9
Productivity[4]	-64.2	-	64.2	-64.2	-	64.2
Total	**1,373.3**	**1,504.6**	**131.3**	**1,631.8**	**1,479.3**	**-152.5**

In 2025, Hydro One's transmission capital expenditures for 2025 were 9.6% above the OEB-approved amount and ISAs were 9.3% below the OEB-approved amount. Transmission capital expenditures were higher largely due to increased spending in the System Access and System Service categories. Increased expenditures in System Service were primarily driven by mandatory transmission work required by governmental authorities (externally driven work). The decrease in transmission ISAs was due to lower System Renewal additions. Furthermore, expenditure variances at the OEB-category level were impacted by inflationary pressures including rising costs of goods, services, and labour. Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible. The OEB categories and associated variance explanations are summarized below.

System Access: System Access capital expenditures were $85.9M above the OEB-approved amount. This variance was primarily driven by Centennial TS connection (T-SA-Other), where the customer has selected the province of Ontario and the City of St Thomas

[2] Does not include Hydro One affiliates or future Affiliate Transmission Lines Projects (ATP).
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)
[4] Productivity is reflected in Actual expenditures.

in which to invest $7.0B in a large-scale EV battery manufacturing facility. The proposed connection plan to supply the customer facility consists of building two new 230 kV double-circuit transmission line taps and a new 230/27.6 kV transmission station. The variance was also caused by Belleville TS: Build 75/125 MVA, 230/44 kV DESN project (T-SA-Other) which is required to provide additional capacity in the region of Belleville as the projected load is expected to exceed the current capacity available from the existing Belleville TS. System Access ISAs were $35.3M above the OEB-approved amount primarily due to the addition of Wallaceburg TS: Conversion from 115 kV to 230 kV (T-SA-Other) to support the St. Clair Transmission Line project as directed by the Independent Electricity System Operator (IESO).

System Renewal: System Renewal capital expenditures were $68.7M below the OEB-approved amount. This variance was primarily driven by the deferral of several transmission line refurbishment projects (T-SR-13), including the refurbishments of L22H Easton Junction x Hinchinbrook, A4L Beardmore x Longlac TS, D2/3H Hunta SS x Abitibi Canyon Junction and T33E Almonte TS x Oshawa North Junction. The variance was also caused by a reduction in the Transmission Lines Insulator Replacement Program (T-SR-08) which experienced system outage constraints and the diversion of crews to storm and wildfire restoration work.

System Renewal ISAs were $166.1M below the OEB-approved amount due to the factors noted above, along with scope reduction and re-pacing of the Gardiner TS: T1/T2 PCT Component Replacement project (T-SR-03) due to equipment failure which shifted the expected in-service year from 2025 to 2026. The System Renewal ISA decrease was partially offset by the acceleration of the Bruce A 500kV Switchyard Replacement project (T-SR-02), which achieved a project milestone in 2025, and reflects $337.9M of ISAs that were not included in the 2025 Forecast.

System Service: System Service expenditures were $50.7M above the OEB-approved amount. This variance was primarily driven by the advancement of planning work for St. Clair Transmission Line: Stations Work (T-SS-09) and the refinement of execution

methods for Richview Manby Transmission Reinforcement – Line (T-SS-06) to minimize disruption to the community.

System Service ISAs were $94.9M below the OEB-approved amount primarily driven by Chatham SS x Lakeshore TS: Stations Work (T-SS-07) which was completed a year ahead of schedule.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One takes an integrated approach to transmission portfolio management and manages to the overall capital envelope. The approach recognizes that changes at both the project and program levels will occur. Individual variances, whether at the annual or project total level, are to be expected given the magnitude and complexity of the work being performed. Each project involves a unique combination of elements related to the scope of work included and site conditions and is undertaken pursuant to a defined project delivery process with a range of expected outcomes as defined by the Association for the Advancement of Cost Engineering (AACE) class of estimate.[5] Projects are typically released for execution and funded based on a Class 3 estimate. As projects are executed, they are managed to allow Hydro One to be responsive to execution challenges and update project scope, where required, while continuing to deliver the projects according to Hydro One's project delivery process.

At Hydro One, projects are governed with a focus on adherence to the total project budget. In-year amounts are managed from a portfolio perspective recognizing the multitude of internal and external pressures across the portfolio. As such, project performance is shown in this report in reference to project total variances and overall project schedule variances. Programs are different in that the budget is set annually and are managed and governed against these budgets. As such, program performance is discussed in the context of adherence to annual budgets.

[5] AACE estimate classification is discussed in TSP Section 2.11.

3.1 OVERVIEW

The projects and programs discussed in this report represent 95% of the 2025 actual ISAs that are shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

Hydro One's performance in relation to material[6] projects with AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2), is presented in Figure 1 below.[7] The blue vertical lines in the cost variance chart are placed at -20% and +30% which represent the range of expected outcomes that most commonly aligns with an AACE Class 3 estimate, and are representative of the typical project definition work completed at the time of business case approval at Hydro One. The figure shows a relatively tight dispersion of cost performance with the majority of projects (71%, or 15 of 21) having project variances below the AACE upper range, which is a reasonable result given the significant cost pressures experienced in recent years and is an improvement relative to 2024. The overall variance for the 21 projects is +8% which is within the AACE Class 3 estimate range. Hydro One utilizes its Capital Project Delivery model to manage and remain effective in executing projects within the range anticipated when the project budgets were established. This is particularly true for larger projects that are subject to increased rigour and scrutiny as part of the project delivery process.

[6]Greater than or equal to $4M, and with actual or planned ISA in 2025
[7] This provides a more consistent evaluation of AACE Class 3-based project estimates against the AACE Class 3 estimate accuracy range.

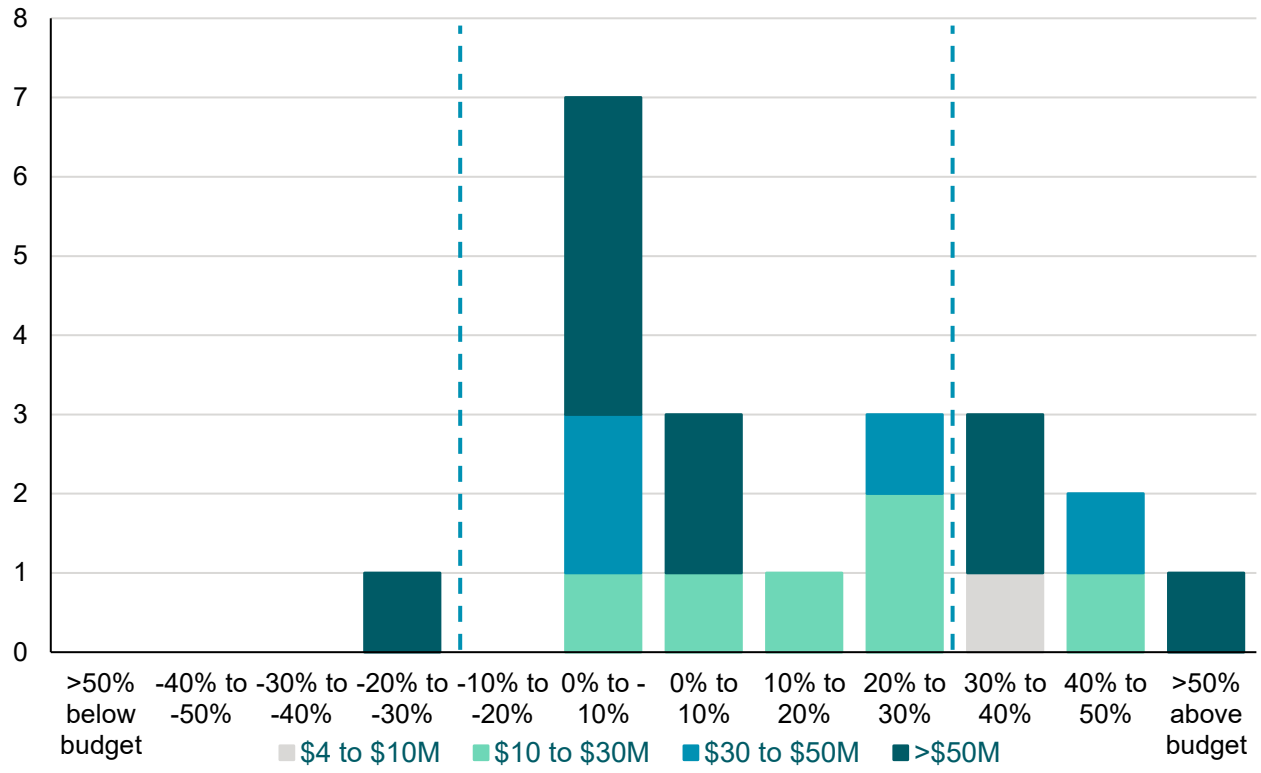

Figure 1: Material Project Cost Variance Dispersion[8]

Similarly, Figure 2 shows that the majority of projects (57%, or 12 of 21) were completed or are forecast to complete on plan, within 12 months of baseline.

[8] Based on actual cost for completed projects and forecast cost at completion for projects still in progress.

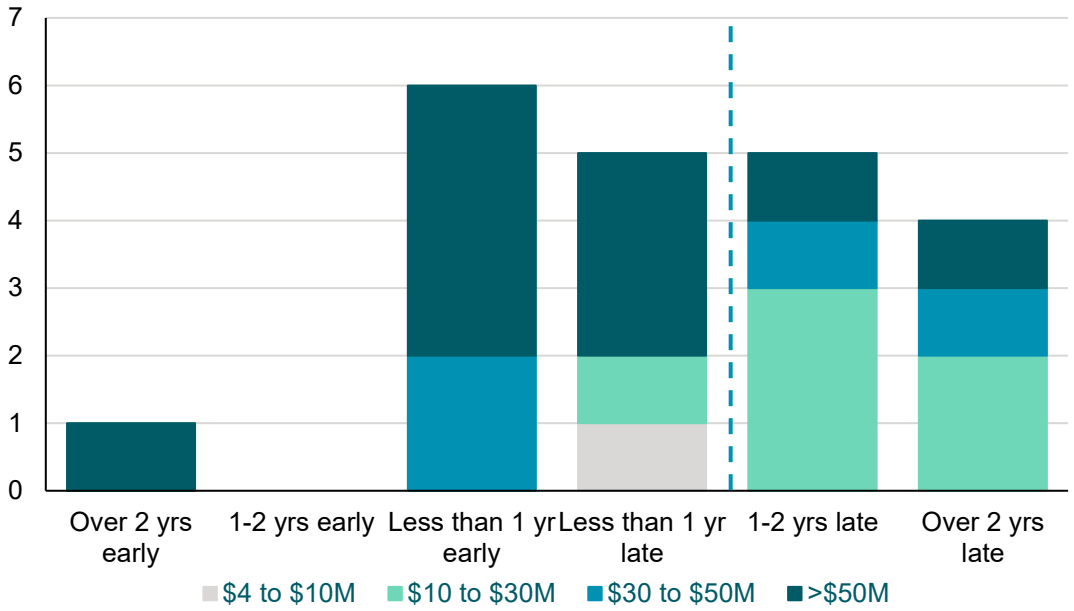

Figure 2: Material Projects Schedule Variance Dispersion[9]

3.2 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISAs in 2025 greater than or equal to $4M have been summarized in the tables below, along with variance explanations. The thresholds used by Hydro One to identify material variances were determined using the following criteria[10]:

- **Cost Variances** – Material cost variances were identified where the in-year cost variance for a program, or the total project end cost variance was greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – Material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2025 or earlier, to a later year.

[9] Based on actual in-service date for completed projects and forecast in-service date for projects still in progress.
[10] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

The reasons for variances in individual projects and programs fall into four categories: (1) Emergent Needs, (2) Execution Factors, (3) Work Definition, and (4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One makes in response to a change in priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work, which can include timing changes that arise as a result of changing conditions, risks, or priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact on cost, schedule, and resources. This can change the year in which the project goes in-service without materially changing the ISA or affecting the overall scope of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs**.**

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget, and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known during the design and estimate and execution phases.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROJECT PERFORMANCE

As summarized in Table 3 below, transmission projects are managed with a focus on adherence to the overall project total budget and project schedule.

1

Table 3 - Transmission Project Summary

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
System Access													
Generator Customer Connection													
Hagersville Battery Storage -ELT1	Complete	T-SA-Other	0.0	3.5	0.0	4.1	0.0	4.1	4.1	-	2025	-	Emergent Needs
Load Customer Connection													
Bayfront Facility - EAF Project	Planning	T-SA-Other	21.2	0.0	49.0	0.0	49.0	25.6	-23.4	2025	2030	5	Reprioritization
Islington TS New 230 kV Customer Connection	Complete	T-SA-01	0.0	9.5	18.0	21.7	18.0	21.7	3.7	2025	2025	0	Execution Factors
South Middle Road TS DESN 2: 230/27.6 kV DESN	Complete	T-SA-10	3.8	3.0	44.1	39.2	44.8	41.9	-2.8	2025	2025	0	Not Applicable
Wallaceburg TS: Conversion from 115 kV to 230 kV	Execution	T-SA-Other	0.0	13.5	0.0	28.7	0.0	39.9	39.9	-	2028	-	Emergent Needs
System Renewal													
Integrated Station Investment													
Algoma TS: Component Replacement	Planning	T-SR-01	7.0	0.0	7.4	0.0	30.9	25.8	-5.1	2027	2034	7	Not Applicable
Beck 1 SS: ABCB Replacement	Execution	T-SR-02	9.0	3.7	29.9	9.3	54.2	38.3	-15.9	2026	2026	0	Not Applicable
Bracebridge TS: T1 & Component Replacement	Complete	T-SR-03	3.0	11.6	0.0	18.0	8.2	18.4	10.2	2026	2025	-1	Work Definition
Bridgman TS Load Station Transformer Replacement	Execution	T-SR-03	0.0	9.2	0.0	9.0	69.3	91.0	21.7	2024	2026	2	Execution Factors

[11] Phases: Planning, Execution, Complete, or Cancelled.

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Bruce A TS: 500 kV Switchyard Replacement	Execution	T-SR-02	44.4	88.9	0.0	337.9	316.2	487.8	171.6	2027	2027	0	Execution Factors
Bruce B SS: ABCB Replacement	Complete	T-SR-02	0.0	3.6	0.0	4.2	182.3	177.4	-4.9	2024	2022	-2	Not Applicable
Charles TS: T3, T4 & Component Replacement	Execution	T-SR-03	8.3	3.2	19.9	0.0	27.9	48.7	20.9	2026	2027	1	Work Definition
Cherrywood TS: 500 kV ABCB Replacement (Phase 3-1)	Complete	T-SR-02	2.2	2.6	7.0	4.2	74.8	72.1	-2.7	2025	2025	0	Not Applicable
Claireville TS: Component Replacement	Execution	T-SR-01	0.9	1.6	5.3	2.6	27.9	35.9	7.9	2025	2026	1	Execution Factors
Crowland TS: T5, T6 & Component Replacement	Cancelled	T-SR-03	11.6	0.1	33.2	0.0	33.9	-	-	2026	-	-	Not Applicable
Duplex TS: T1, T2, T3, T4 & Component Replacement	Planning	T-SR-03	9.8	0.1	9.3	0.0	22.3	89.0	66.7	2026	2034	8	Work Definition
Elliot Lake TS: Component Replacement	Execution	T-SR-03	7.5	8.0	11.5	0.0	23.5	33.7	10.3	2026	2026	0	Work Definition
Gardiner TS: T1, T2, PCT & Component Replacement	Execution	T-SR-03	26.0	21.6	61.9	0.0	61.9	39.5	-22.4	2025	2026	1	Emergent Needs
Glendale TS: Station Refurbishment and Reconfiguration	Planning	T-SR-03	8.5	0.6	9.7	0.0	52.9	32.4	-20.5	2027	2031	4	Not Applicable
Hunta SS: Component Replacement	Planning	T-SR-01	4.7	0.1	9.4	0.0	10.9	14.6	3.7	2025	2030	5	Reprioritization
John TS: T5 and T6 Transformer Replacement	Complete	T-SR-03	9.0	9.1	15.7	27.5	25.9	27.5	1.6	2025	2025	0	Not Applicable
Kirkland Lake TS: Component Replacement	Execution	T-SR-03	2.5	3.7	8.0	6.1	27.9	35.9	8.0	2025	2027	2	Execution Factors
Lake TS: T2 & Component Replacement	Complete	T-SR-03	8.1	0.2	8.0	0.2	39.9	11.9	-28.0	2026	2024	-2	Not Applicable
Lauzon TS: T6, T5 & Component Replacement	Execution	T-SR-03	10.8	31.3	32.0	42.7	64.1	69.5	5.5	2026	2026	0	Not Applicable

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Lennox TS: ABCB Component Replacement	Complete	T-SR-02	10.7	8.1	11.0	8.2	143.2	148.0	4.8	2026	2025	-1	Not Applicable
Lisgar TS: T1 and Component Replacement	Execution	T-SR-03	0.0	7.5	0.0	7.3	18.1	15.0	-3.1	2031	2026	-5	Not Applicable
Longueuil TS: T3, T4 Component Replacement	Complete	T-SR-03	10.5	9.6	0.0	28.4	24.9	29.5	4.6	2026	2025	-1	Execution Factors
Longwood TS: Component Replacement	Execution	T-SR-03	0.7	1.5	14.7	1.7	14.7	16.3	1.6	2025	2026	1	Work Definition
Mackenzie TS: Component Replacement - Phase 1	Complete	T-SR-01	15.7	18.6	28.3	60.7	47.3	60.9	13.6	2025	2025	0	Work Definition
Main TS: T3, T4 & Component Replacement	Execution	T-SR-03	2.6	13.9	2.6	36.7	48.0	67.3	19.2	2024	2026	2	Execution Factors
Marathon TS: Component Replacement	Execution	T-SR-01	11.1	2.5	11.3	0.0	30.7	36.6	5.9	2026	2028	2	Work Definition
Merivale TS Refurbishment	Execution	T-SR-01 T-SS-05	58.0	88.6	0.0	63.0	297.4	281.0	-16.4	2027	2029	2	Not Applicable
Middleport TS: ABCB Replacement	Complete	T-SR-02	10.0	7.5	34.6	8.1	178.1	165.5	-12.5	2025	2025	0	Not Applicable
Middleport TS: T6 Replacement	Complete	T-SR-01	6.1	14.5	25.4	16.4	24.9	25.7	0.8	2025	2025	0	Not Applicable
Midhurst TS: T4 & Component Replacement	Planning	T-SR-03	3.7	0.0	8.7	0.0	11.0	17.0	6.0	2025	2032	7	Reprioritization
Milton SS: Component Replacement	Execution	T-SR-01	0.0	3.1	0.0	5.9	20.0	28.8	8.9	2024	2028	4	Execution Factors
Murray TS: T11, T12 & Component Replacement	Planning	T-SR-03	17.0	0.9	38.1	0.0	39.6	60.8	21.3	2025	2032	7	Reprioritization
Nanticoke TS: ABCB Replacement	Execution	T-SR-02	6.6	8.0	15.0	10.8	79.0	81.9	2.9	2026	2027	1	Not Applicable
Newton TS: HV Breakers & Component Replacement	Cancelled	T-SR-03	5.4	0.1	13.7	0.0	13.8	-	-	2025	-	-	Not Applicable
Orillia TS: Component Replacement	Execution	T-SR-03	4.8	12.1	11.0	0.0	11.0	31.2	20.3	2025	2026	1	Work Definition

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Otto Holden TS: T3/T4 & Component Replacement	Execution	T-SR-01	12.2	29.6	11.3	2.7	68.7	102.4	33.7	2027	2028	1	Work Definition
Palermo TS: T3, T4 Replacement & Station Expansion	Execution	T-SR-03	7.0	7.8	7.2	0.0	34.3	54.7	20.5	2027	2027	0	Work Definition
Porcupine TS: Component Replacement	Execution	T-SR-01	23.5	13.7	34.0	32.5	88.8	86.9	-1.9	2026	2026	0	Not Applicable
Preston TS: T3, T4 & Component Replacement	Execution	T-SR-03	10.8	24.6	11.3	28.5	23.7	52.0	28.3	2026	2027	1	Work Definition
Russell TS: T1, T2 & Component Replacement	Execution	T-SR-03	12.4	13.2	10.8	0.0	28.6	41.9	13.3	2026	2027	1	Work Definition
Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement	Execution	T-SR-01	0.0	22.7	0.0	53.5	53.6	70.0	16.4	2024	2027	3	Work Definition
Strachan TS: T14 & Component Replacement	Execution	T-SR-03	0.2	2.3	10.9	0.0	10.9	16.6	5.7	2025	2027	2	Execution Factors
Wawa TS: Component Replacement	Execution	T-SR-01	16.9	19.5	21.0	3.7	60.1	99.0	38.9	2026	2029	3	Execution Factors
Whitedog Falls SS: Component Replacement	Complete	T-SR-01	0.1	4.5	0.0	8.9	8.8	12.1	3.3	2025	2025	0	Work Definition
Wonderland TS: T5, PCT & Component Replacement	Cancelled	T-SR-03	11.7	0.0	12.5	0.0	27.0	-	-	2026	-	-	Not Applicable
Overhead Lines Refurbishment Projects, Component Replacement Programs													
A4L Transmission Line Refurbishment	Planning	T-SR-13	23.8	0.0	36.4	0.0	49.1	35.6	-13.5	2025	2031	6	Reprioritization
B5/6C Transmission Line Refurbishment	Execution	T-SR-13	3.1	1.6	17.2	2.8	24.0	24.0	0.0	2025	2026	1	Execution Factors
D2/3H Transmission Line Refurbishment	Planning	T-SR-13	19.1	0.1	22.2	0.0	96.3	189.2	92.9	2026	2031	5	Work Definition
D6 Transmission Line Refurbishment	Execution	T-SR-13	1.7	1.3	7.3	0.0	42.8	55.6	12.8	2025	2028	3	Execution Factors
E1C Transmission Line Refurbishment	Planning	T-SR-13	17.3	0.1	19.2	0.0	55.2	67.9	12.7	2026	2031	5	Reprioritization

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
E8V/E9V Transmission Line Refurbishment	Planning	T-SR-13	13.0	0.0	7.2	0.0	61.9	25.0	-36.9	2027	2031	4	Not Applicable
H1L/H3L/H6LC/H8LC Transmission Line Refurbishment	Planning	T-SR-13	3.2	0.0	6.0	0.0	6.0	17.5	11.4	2025	2031	6	Reprioritization
L22H Transmission Line Refurbishment	Planning	T-SR-13	26.8	0.0	24.7	0.0	61.3	64.5	3.2	2026	2035	9	Not Applicable
M6/7E Transmission Line Refurbishment	Cancelled	T-SR-13	12.8	0.0	7.1	0.0	26.8	-	-	2026	-	-	Not Applicable
N5K Transmission Line Refurbishment[12]	Cancelled	T-SR-13	10.9	0.0	7.4	0.0	34.8	-	-	2027	-	-	Not Applicable
Q2AH Transmission Line Refurbishment	Planning	T-SR-13	3.9	0.0	9.7	0.0	9.7	11.5	1.9	2025	2031	6	Reprioritization
S2N Transmission Line Refurbishment	Planning	T-SR-13	7.0	0.0	7.2	0.0	29.6	22.6	-7.0	2027	2031	4	Not Applicable
T33E Transmission Line Refurbishment	Planning	T-SR-13	18.2	0.0	15.3	0.0	118.3	230.2	111.9	2027	2032	5	Reprioritization
Protection and Automation													
Ottawa Ring 9 Fibre Infrastructure Development	Execution	T-SR-17	5.6	6.3	0.0	14.3	22.0	24.5	2.5	2026	2026	0	Execution Factors
Telecom Performance - Ring 6 OPGW (B22D,Hannover)	Planning	T-SR-12	4.0	0.0	11.1	0.0	11.1	29.4	18.3	2025	2030	5	Reprioritization
System Service													
Enabling Facilities - Government Project													
Keith TS: Replace 6-115 kV Breakers	Complete	T-SS-Other	0.0	3.3	0.0	4.5	0.0	10.5	10.5	-	2025	-	Emergent Needs
Inter Area Network Capability													

[12] Project being addressed as part of the St. Clair Transmission Line project

Project Characteristics			2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[11]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Chatham SS x Lakeshore TS: Stations Work	Complete	T-SS-07	3.9	0.9	32.4	0.9	32.4	29.5	-2.9	2025	2024	-1	Not Applicable
Local Area Supply Adequacy													
Richview Manby Transmission Reinforcement - Line	Execution	T-SS-06	12.3	19.7	0.0	35.3	32.6	61.6	28.9	2026	2026	0	Work Definition
Richview x Trafalgar 230 kV Conductor Upgrade	Complete	T-SS-04	9.5	16.2	0.0	28.6	59.3	80.3	21.0	2026	2025	-1	Execution Factors

The following is an overview of the more significant cost and schedule variances for projects that had AACE Class 3 estimates at the time the Settlement Proposal was implemented (see Section 1.2).

The **Wawa TS: Component Replacement (T-SR-01)** project is forecast to exceed its budget by $38.9M, predominantly due to input cost pressures and increased project complexity including requirements for several temporary line bypasses to accommodate a power-outage staging plan in the region. **Bridgman TS Load Station Transformer Replacement (T-SR-03)** is forecast to exceed its $69.3M budget by $21.7M for a latest total project forecast of $91.0M due to changes in the contingency tie cable design to meet Toronto Hydro's requirements, design maturity, constructability challenges, and cost escalations for cable relocation work completed by Toronto Hydro. These factors, along with material delivery delays and outage management constraints, led to a schedule delay as well, shifting project completion from 2024 to 2026. However, project savings of approximately $8.0M were realized through value engineering and risk management, reducing the overall project cost and mitigating additional cost pressures. **Richview x Trafalgar 230 kV Conductor Upgrade (T-SS-04)** was completed above budget by $21.0M, primarily due to changes in project definition assumptions, including permit-related requirements, construction complexity associated with crossing multiple highways and procurement escalations. Through partial in-servicing and risk management, cost savings of approximately $5.0M were realized, helping to offset cost pressures.

The **Beck 1 SS: ABCB Replacement (T-SR-02)** project is forecast to be completed $15.9M below budget due to the reduced impact of execution factors. This was achieved through effective project execution, enhanced stakeholder coordination, and construction optimization initiatives. Similarly, **Middleport TS: ABCB Replacement (T-SR-02)** project was completed $12.5M below budget due to construction efficiency and effective risk management, and scope optimization. The use of pre-built and partially commissioned panels enabled work to be completed ahead of outages, ensuring that outage windows could be executed as planned and mitigating project risk.

The following is an overview of the more significant cost and schedule variances for projects that did not have an AACE Class 3 estimate at the time the Settlement Proposal was implemented (see Section 1.2).

The Bruce A TS: 500kV Switchyard Replacement (T-SR-02) project is forecast to exceed its $316.2M budget by $171.6M based on the latest total project forecast of $487.8M, with the forecast in-service year remaining as 2027. The original forecast for the 500kV gas insulated switchgear (GIS) was developed based on an earlier investment at the Bruce Nuclear Complex, using pre-pandemic prices. The specialized nature of the required GIS and post-pandemic market forces resulted in higher actual costs for the required equipment. Additional scope was added to the project as well to improve reliability, operational flexibility, and maintainability. Following scope development, an AACE Class 3 estimate was completed with a value of $516.5M and is now forecast to be completed $28.7M below the estimate ($487.8M). Through accelerating the ISAs, the contingency and commissioning costs were lowered, effectively reducing the overall project cost by approximately $30M. Several **Transmission Line Refurbishment (T-SR-13)** projects have experienced cost increases due to maturity and cost escalation factors, and have subsequently been deferred to manage expenditures toward the overall capital envelope, notably T33E Transmission Line Refurbishment and D2/3H Transmission Line Refurbishment. **Duplex TS: T1, T2, T3, T4 & Component Replacement (T-SR-03)** is forecast to exceed its $22.3M budget by $66.7M, with the latest total project forecast of $89.0M, due to updated estimates based on recent comparable projects and the incorporation of scope from another investment at the same site. The integrated scope includes the replacement of two additional transformers and associated end-of-life equipment.

The **Lake TS: T2 & Component Replacement (T-SR-03)** project was completed $28.0M below budget due to a reduction in scope. The original scope included the replacement of three transformers; however, following an opportunity to acquire adjacent land, two of the transformers were moved to a separate future investment at the site. This approach significantly reduced safety, staging, and outage risks while providing flexibility for future

load growth. Similarly, **Gardiner TS: T1, T2, PCT & Component Replacement (T-SR-03)** project is forecast to be completed $22.4M below budget due to scope optimization that prioritized the highest risk assets (i.e. transformers), deferring PCT equipment and medium voltage switchgear replacement to a separate investment. Further savings were realized through construction efficiencies and the use of spare materials from other projects. **Merivale TS Refurbishment (T-SR-01 / T-SS-05)** project is forecast to be completed $16.4M below budget due to contract management where a separate supply vendor and installation general contractor approach was used to balance risk-reward and improve overall cost competitiveness. Additional savings were achieved through early outage availability that accelerated the completion of the west yard a month ahead of schedule, as well as execution efficiencies including design optimization, re-use of existing facilities, and optimized construction sequencing.

5.0 PROGRAM PERFORMANCE

Consistent with the previously discussed reprioritization of work in the System Renewal category to accommodate pressures across the portfolio, aggregate capital expenditure and ISAs for System Renewal programs in Table 4 were below the overall Forecast amounts by -$21.6M and -$16.0M, respectively. This reflects the reprioritization of work toward mandatory, customer-driven, and other high-priority investments while continuing to operate towards the OEB-approved expenditure envelope.

1

Table 4 - Transmission Program Summary

Program Characteristics		2025 Transmission Capital Expenditures ($M)			2025 Transmission In-Service Additions ($M)			2025 Tx Units				Performance
Program Description	EB-2021-0110 ISD Number	Forecast	Actual	Variance	Forecast	Actual	Variance	Unit Description	Forecast	Actual	Variance	Variance Category
System Renewal												
Wood Pole Structure Replacement	T-SR-04	57.6	60.6	2.9	57.5	69.1	11.6	# of Structures	944	820	-124	Execution Factors
Steel Structure Coating Program	T-SR-05	20.0	0.4	-19.7	20.0	0.1	-19.9	# of Structures	478	0	-478	Reprioritization
Tx Lines Foundation Assess/Clean/Coat, Life Extension & Tower Member Refurbishment Program	T-SR-06	14.4	14.7	0.3	14.4	14.4	0.0	# of Structures	1354	1363	9	Not Applicable
Transmission Line Shieldwire Replacement	T-SR-07	13.2	20.4	7.2	13.2	18.9	5.8	# of km	297	274	-23	Work Definition
Transmission Line Insulator Replacement	T-SR-08	79.0	53.7	-25.3	78.6	48.3	-30.4	# of Circuit Structures	3690	2536	-1154	Reprioritization
Transmission Station Demand, Spares and Targeted Assets	T-SR-09	72.9	77.1	4.2	58.9	77.3	18.4	N/A	N/A	N/A	N/A	Execution Factors
Protection Relay Replacement Program	T-SR-10	10.5	19.2	8.7	10.4	12.1	1.7	# of Upgrades	45	48	3	Execution Factors
Tx Lines Emergency Replacements	T-SR-15	11.2	12.8	1.6	11.0	10.9	-0.2	# of Work Orders	115	74	-41	Execution Factors
Fiber Entrance Installation and Completion of OPGW	T-SR-17	6.9	0.8	-6.1	4.1	0.7	-3.4	N/A	N/A	N/A	N/A	Not Applicable
Tx RTU Replacement Program	T-SR-Other	6.9	11.5	4.6	6.8	7.2	0.4	# of RTUs	8	14	6	Execution Factors

Reductions in both expenditures and accomplishments are noted in the **Transmission Line Insulator Replacement (T-SR-08)** and **Steel Structure Coating (T-SR-05)** programs due to reprioritization of work, along with system outage constraints. For the Transmission Line Insulator Replacement program, the diversion of crews to storm and wildfire restoration work was also a factor.

Other programs that experienced material variances were:

- The **Wood Pole Structure Replacement (T-SR-04)** program had higher expenditures and ISAs because of carry-over work and partial completions were capitalized.
- The **Transmission Line Shieldwire Replacement (T-SR-07)** program had higher expenditures and reduced accomplishment due to more complex work, including the replacement of shieldwire with optical ground wire (OPGW), which is more costly due to tower peak modifications and required fibre optic cable work.
- The **Transmission Station Demand, Spares and Targeted Assets (T-SR-09)** program had higher expenditures due to the early delivery of a transformer.
- The **Protection Relay Replacement (T-SR-10)** program had higher expenditures due to work deferred from the previous year to 2025 to accommodate priority investments and the transfer of costs to the program associated with Bunting TS Standard Development that were not included in the original budget.
- **Transmission Lines Emergency Replacements (T-SR-15)** had higher expenditures due to wildfire restoration work, which resulted in more expensive repairs and lower accomplishments due to fewer emergency failures and outage constraints.
- The **Remote Terminal Unit** (**RTU) Replacement (T-SR-Other)** program had higher expenditures and accomplishments due to work deferred to 2025 from the previous year and work advanced from 2026 due to resource availability.

Section 2.2

2025 Distribution Capital Performance Report

DISTRIBUTION CAPITAL PERFORMANCE REPORT – 2025

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2025 in relation to the overall Distribution capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One.

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached a settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

2.0 PERFORMANCE AT THE OVERALL ENVELOPE AND OEB CATEGORY LEVEL

Table 1 below presents a breakdown of the actual 2025 capital Distribution expenditures and ISA by OEB investment category and compares them to the OEB-approved values. The primary focus of this report is on the Distribution System Access, System Renewal, and System Service categories. The Distribution General Plant category is discussed in the General Plant Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 and p.257-258.

Table 1 - 2025 Distribution Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2025			In-Service Additions – 2025		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$238.9	$340.6	$101.7	$239.4	$333.7	$94.3
System Renewal (Excl. AMI 2.0)	$ 280.6	$422.3	$141.7	$289.1	$419.7	$130.6
System Renewal (AMI 2.0 Only)	$158.4	$94.6	-$63.8	$158.4	$146.7	-$11.7
System Service	$ 212.6	$108.4	-$104.2	$232.6	$155.7	-$77.0
General Plant	$149.5	$118.7	-$30.7	$193.7	$195.2	$1.6
Total	**$1,040.0**	**$1,084.6**	**$44.6**	**$1,113.1**	**$1,250.9**	**$137.8**

In 2025, Hydro One's distribution capital expenditures were 4% above the OEB-approved amount and ISAs were 12% above the OEB-approved amount. Distribution capital expenditures and ISAs were higher due to System Access expenditures related to increased customer connection requests, more complex connection projects, and mandatory Joint Use and Relocation work (Externally Driven Work). In addition, higher System Renewal investments were required to respond to major weather events predominantly the March 2025 Ice Storm and polychlorinated biphenyls (PCBs) equipment replacement required to meet deadlines associated with environmental regulations. Furthermore, expenditure variances at the OEB-category level were impacted by inflationary pressures, including rising costs of goods, services, and labour. Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so.

To partly offset these increases in the System Access category (i.e., customer-driven), and the System Renewal category (i.e., emergency, demand-driven and compliance), Hydro One made reductions in certain System Renewal (i.e., sustainment and replacement) and System Service (i.e., energy storage solutions, system capacity and feeder modernization) programs. Further, lower General Plant and AMI 2.0 expenditures

[2] Does not include Hydro One affiliates.
[3] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

helped mitigate these increases. The OEB categories and associated variance explanations are summarized below.

System Access: System Access capital expenditures and ISAs were higher than the OEB-approved amount by $101.7M and $94.3M, respectively. These variances were primarily driven by higher expenditures in New Load Connections and Upgrades (D-SA-02), reflecting a greater number of large connection requests, and increased project scope and complexity. In addition, Joint Use and Lines Relocations (D-SA-01) expenditures were above the forecast due to sustained higher externally driven work volumes, including more complex line relocation projects and third-party attachment requests. Meter Infrastructure Sustainment (D-SA-04) did not have a material impact on the System Access category variance.

System Renewal: System Renewal capital expenditures and ISAs were higher than the OEB-approved amount by $77.9M and $118.9M, respectively. These variances were primarily driven by higher expenditures in Distribution Lines Trouble Call and Storm Damage Response (D-SR-05), predominantly due to the March 2025 Ice Storm; Distribution Lines PCB Equipment Replacement (D-SR-06), to meet deadlines associated with environmental regulations; and Distribution Stations Demand Capital (D-SR-01), due to emergent needs driven by higher equipment failures. To help mitigate these impacts, Hydro One reprioritized the funding of specific planned System Renewal work, including Pole Sustainment (D-SR-07), Station Renewal (D-SR-04), Submarine Cable Replacement (D-SR-09), Distribution Lines Sustainment Initiatives (D-SR-10), and other planned station component replacement work. Within Distribution Lines Minor Component Replacement (D-SR-08), overall expenditures were below forecast; with most programs having lower accomplishments with the exception of sentinel light-related activities that were higher due to PCB compliance requirements. The Advanced Meter Infrastructure (AMI 2.0) project (D-SR-12) also had lower expenditures and ISAs in 2025 as the project pacing was adjusted, as discussed further in Section 5 below.

System Service: System Service capital expenditures and ISAs were lower than the OEB-approved amount by $104.2M and $77.0M, respectively. These variances were primarily driven by work reprioritization in Energy Storage Solutions (D-SS-04), Worst Performing Feeders (D-SS-05), and Load Growth Projects (D-SS-01), reflecting reductions in planned energy storage, feeder modernization, and system capacity work. These reductions were partly offset by higher expenditures in Demand Investments (D-SS-03), driven by localized load growth and system constraints.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One's Distribution expenditures consist of programs and projects. Programs involve work that is repeatable in nature on a specific asset type that reoccurs every year and the assets are largely in-serviced in the same fiscal year. Projects are stand-alone jobs with a discrete beginning and end which may span over more than one fiscal year and are not in-serviced until they are energized. Capital expenditure variances at the program-level are discussed in Section 4.0, and project-level variances are discussed in Section 5.0.

The projects and programs discussed in this report represent 92% of the 2025 actual ISA that is shown in Table 1 (for the System Access, System Renewal and System Service categories) and as such provide a very strong indication of the overall portfolio performance.

Performance Definitions

Projects and programs with planned or actual ISA in 2025 greater than or equal to $3M have been summarized in the following sub-sections along with variance explanations. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria[4]:

[4] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2025 or earlier, to a later year.

The reasons for variances in individual projects and programs fall into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes that arise as a result of changing conditions, risks, and priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact to cost, schedule, and resources. This can change the year in which the project goes in-service without necessarily materially changing the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors, as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or

decreases in project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

4.0 PROGRAM PERFORMANCE

A large portion of Distribution's capital work program includes investments that are driven by demand and require action in a specified period as part of Hydro One's obligations under the Distribution System Code. While Hydro One makes every effort to work within its budget, there are times when an influx of demand work results in a reprioritization of resources away from planned work. Hydro One has a robust reprioritization process that provides the flexibility necessary to reprioritize investments to respond to fluctuations in emergent work while aiming to minimize the impacts of deferring planned investments that can introduce additional risks to the system in future years. Distribution Capital Program variances are summarized in Table 2 and further discussed below.

Table 2 - Distribution Program Summary[5]

			2025 Dx Capital Expenditures ($M)			2025 Dx In-Service Additions ($M)			2025 Dx Units				Performance
OEB Category	**Program Description**		**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
System Access	D-SA-01	Joint Use and Relocations	28.5	40.5	11.9	28.7	33.3	4.6	None	n/a	n/a	n/a	Emergent Needs
	D-SA-02	New Load Connections, Upgrades and Cancellations	166.8	252.3	85.5	166.8	251.1	84.2	# of Connections & Upgrades	21,317	20,353	-964	Work Definition
	D-SA-04	Metering Sustainment	43.4	42.6	-0.8	43.6	42.8	-0.8	# of Meters Replaced	54,916	54,399	-517	Not Applicable
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.7	12.0	5.2	6.7	13.4	6.7	None	n/a	n/a	n/a	Emergent Needs
	D-SR-02	Mobile Unit Substation Program	3.3	1.4	-1.8	4.1	4.1	0.1	# of MUS	1	1	0	Reprioritization
	D-SR-03	Distribution Station Planned Component Replacement Program	4.1	0.6	-3.5	4.3	3.2	-1.2	# of Recloser & MUS Structures	109	219	110	Reprioritization
	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	116.1	332.5	216.5	116.1	329.9	213.8	None	n/a	n/a	n/a	Emergent Needs
	D-SR-06	Distribution Lines PCB Equipment Replacement Program	10.0	23.5	13.6	10.0	23.7	13.8	# of Transformer Replacements	1,476	1,735	259	Execution Factors
	D-SR-07	Pole Sustainment	60.5	16.0	-44.5	60.5	16.4	-44.1	# of Pole Replacements	5,976	1,034	-4,942	Reprioritization
	D-SR-07	Wood Pole Test and Treat	10.8	0.5	-10.3	10.8	0.4	-10.4	# of Poles Tested	101,598	3,366	-98,232	Reprioritization
	D-SR-07	Wood Pole Structural Refurbishment	6.6	-0.2	-6.9	6.7	-0.2	-6.9	# of Poles Refurbished	2,785	0	-2,785	Reprioritization
	D-SR-08	Distribution Lines Minor Component Replacement Program	14.2	11.1	-3.2	14.7	11.0	-3.7	# of Components Replaced	3,275	8,061	4,786	Work Definition
	D-SR-09	Submarine Cable Replacement Program	13.4	1.2	-12.2	13.3	1.5	-11.9	None	n/a	n/a	n/a	Reprioritization
	D-SR-10	Distribution Lines Sustainment Initiatives	8.7	5.5	-3.2	8.7	5.2	-3.5	None	n/a	n/a	n/a	Reprioritization
System Service	D-SS-03	Demand System Modifications	14.4	27.2	12.8	14.2	24.7	10.5	None	n/a	n/a	n/a	Emergent Needs
	D-SS-04	Energy Storage Solutions	29.5	7.9	-21.6	21.0	3.0	-18.0	# of Battery Systems Installed	n/a	75	n/a	Reprioritization
	D-SS-05	Worst Performing Feeders	37.7	14.4	-23.3	37.6	13.9	-23.7	# of Devices	1,296	1,078	-218	Reprioritization
	D-SS-06	Power Quality and Stray Voltage	4.2	5.0	0.8	4.2	5.0	0.8	None	n/a	n/a	n/a	Emergent Needs

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

Witness: Gianni Difilippo

4.1 SYSTEM ACCESS PROGRAMS

The **Joint Use and Lines Relocations (D-SA-01)** program expenditures were above forecast primarily due to sustained higher work volumes, increased complexity associated with large line relocation projects, and the broader cost pressures described in Section 2.0. This work is largely externally driven and is required for Hydro One to meet its contractual obligations to third parties under Joint Use agreements and to maintain compliance with the requirements of Hydro One's distributor licence.

The **New Load Connection, Upgrades, Cancellations (D-SA-02)** program expenditures were above forecast due to a combination of a greater number of large connection requests, increased project scope and complexity, and the broader cost pressures outlined in Section 2.0. Although overall program volumes were lower than forecast, this was mainly attributable to lower subdivision connection volumes in 2025. These subdivision-related volumes are expected to materialize in future periods due to the timing lag between subdivision development and individual residential customers connecting to the distribution system. Excluding this subdivision timing impact, customer connection and upgrade activity was higher than forecast, with a greater proportion of large and complex requests that are more costly to design, estimate, and construct.

The **Metering Sustainment (D-SA-04)** program expenditures were largely in line with the forecast. Program activity was consistent with planned meter sustainment requirements, and the slight variance reflects normal fluctuations in meter replacement needs and execution timing.

4.2 SYSTEM RENEWAL PROGRAMS

The **Distribution Stations Demand Capital (D-SR-01)** program expenditures were above forecast due to emergent needs driven by higher equipment failures. Expenditures under this category vary based on the nature and severity of the equipment failure, which can range from individual component replacements, such as failed switches or electronic reclosers, to more significant transformer replacements. The program was also impacted by the broader cost pressures outlined in Section 2.0.

The **Mobile Unit Substations (MUS) (D-SR-02)** program expenditures were below the forecast due to work reprioritization and the deferral of planned work to future years. In-year expenditures and in-service additions primarily reflected carryover work from 2024.

The **Distribution Station Planned Component Replacement (D-SR-03)** program expenditures were below the forecast due to work reprioritization. As part of Hydro One's portfolio management process, planned station component replacement work was adjusted to prioritize higher-risk mandatory, emergent, and customer-driven work within the overall capital envelope. Replacement work under this planned program will continue to be assessed based on asset condition, safety, reliability risk, and execution requirement. Most of the component replacements were hydraulic reclosers which are less expensive compared to other more expensive components such as MUS structures and switches.

The **Distribution Lines Trouble Call and Storm Damage Response (D-SR-05)** program expenditures were above the forecast predominantly due to the March 2025 Ice Storm. Beginning on March 29, 2025, severe freezing rain and significant ice accumulation caused extensive damage across Hydro One's distribution system, particularly in the Southern, Eastern, and Central regions. The event resulted in approximately 1.2 million service interruptions and impacted over 600,000 customers, representing approximately 42% of Hydro One's customer base. The storm caused substantial damage to distribution assets requiring a significant restoration and rebuild response by Hydro One crews, contractors, and other external crews. While the program also continued to address normal-course trouble calls, equipment failures, and other storm events, the March 2025 Ice Storm was the predominant driver of the variance due to the scale of damage, restoration resources required and associated capital replacement work. The program was also impacted by the broader cost pressures outlined in Section 2.0, including inflationary pressures and rising costs of goods, services, and labour.

The **Distribution Lines PCB Equipment Replacement Program (D-SR-06)** program expenditures exceeded the forecast as Hydro One continued to complete work to replace

equipment containing PCBs to meet deadlines associated with environmental regulations. Replacement costs were also higher where related equipment was replaced or upgraded at the same time to support safe, compliant, and efficient execution on the distribution system, such as poles replaced in conjunction with PCB-filled transformers.

The **Pole Sustainment Program (D-SR-07)** program contains three sub-programs: Pole Replacement, Wood Pole Test and Treat, and Wood Pole Structural Refurbishment. Program expenditures and accomplishments across the three sub-programs were below forecast due to work reprioritization. In 2025, higher overall Distribution capital demand, including mandatory customer-driven work, time-sensitive storm response, and compliance-related work, required Hydro One to reprioritize planned pole sustainment work within the overall capital envelope and allocate resources to higher-priority demand programs.

The **Distribution Lines Minor Component Replacement Program (D-SR-08)** program expenditures were below forecast due to work reprioritization. Although overall expenditures were below forecast, accomplishments were higher than forecast because the work completed included a higher volume of lower-cost sentinel light-related activities. Sentinel light work increased in 2025 as the program shifted to proactive replacement of older mercury vapour fixtures of a vintage associated with PCB content. Replacing these older fixtures supported PCB compliance and remediation requirements to meet deadlines associated with environmental regulations.

The **Submarine Cable Replacement Program (D-SR-09)** program expenditures were below forecast due to work reprioritization to mitigate emergent needs and cost pressures in other programs. Within the reduced level of spending, Hydro One prioritized work on the highest-risk damaged or exposed submarine cables to mitigate public safety risks and maintain reliability.

The **Distribution Lines Sustainment Initiatives (D-SR-10)** program expenditures were below forecast due to work reprioritization to address emergent needs and cost pressures in other programs.

4.3 SYSTEM SERVICE PROGRAMS

The **Demand System Modifications (D-SS-03)** program expenditures were above the forecast due to higher than anticipated investment needs to address localized load growth and system constraints. This work includes minor distribution system modifications that are necessary and urgent to address system needs identified through customer power quality complaints, feeder studies, and system impact assessments.

The **Energy Storage Solutions (D-SS-04)** program expenditures were below the forecast due to work reprioritization. Grid-scale battery energy storage initiatives were largely deferred to respond to emergent needs and cost pressures in other programs. However, development of one Grid Scale project at La Croix First Nation is currently underway. Behind-the-meter residential battery storage for Customers Experiencing Long Interruption Duration (CELID) was also reprioritized. However, Hydro One successfully deployed 75 residential battery storage installations in 2025 and began delivering benefits to participating customers.

The **Worst Performing Feeders Program (D-SS-05)** program expenditures were below the forecast due to work reprioritization to help offset continued pressures from demand-driven and emergency work. Communicating Fault Current Indicator (CFCI) work, which supports fault detection and location, continued and was largely in line with the forecast. Switch-related feeder modernization work, which supports feeder sectionalization and load transfer capability for faster customer power restoration, was reprioritized.

The **Stray Voltage (D-SS-06)** program expenditures were above the forecast due to higher than anticipated requirements to address customer-reported stray voltage and power quality issues.

5.0 PROJECT PERFORMANCE

The Distribution capital envelope is largely program-based; however, some project-based investments are required. For these projects, Hydro One focuses on adherence to the total project cost rather than adherence to in-year expenditures.

Table 3 summarizes the projects that met the performance criteria of a material variance for either timing, scope or cost with detailed explanations for each listed below.

As the Distribution capital work program is largely comprised of programs and smaller projects, few projects meet the $3M variance threshold. Hydro One continues to manage its capital expenditures through its investment planning process which prioritizes investments that respond to mandatory service obligations and mitigate the highest risk for the lowest cost. The balance of risks, system needs, and capital requirements that underpin a project deferral will continue to be monitored and reprioritized in conformance with the investment planning process.

The 15 projects in Table 3 below are either in a Planning, Deferred, Execution, or Completed phase. Of these 15 projects, two did not meet the performance definitions in Section 3.1 above, two were reprioritized primarily because load growth materialized more slowly than forecast, and three were reprioritized to accommodate projects or programs requiring emergent needs. Variance explanations for the remaining eight projects have been provided where required using the criteria outlined in Section 3.1 above.

Table 3 - Distribution Project Summary

			2025 Dx Capital Expenditures ($M)		2025 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[6]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Variance Category**
Wallaceburg DS Relocation	Execution	D-SA-Other	0.0	3.7	0.0	5.5	0.0	5.6	5.6	N/A	2025	N/A	Emergent Needs
Vanastra DS Padmount Transformers	Execution	D-SR-04	0.0	2.0	0.0	6.4	4.3	6.6	2.3	2023	2025	2	Execution Factors
Dymond TS M3 Rebuild - Stage 2	Execution	D-SR-10	2.3	3.1	6.8	0.0	6.8	6.7	-0.1	2025	2026	1	Execution Factors
Enfield TS M4 44KV Line Relocation	Execution	D-SR-10	0.0	5.2	0.0	0.0	0.0	28.0	28.0	N/A	2026	N/A	Emergent Needs
Minden TS M2 Muskoka TS M4 Relocate Tie	Deferred	D-SR-10	4.3	0.0	4.4	0.0	4.4	4.6	0.3	2025	2031	6	Reprioritization
AMI 2.0	Execution	D-SR-12	158.4	94.6	158.4	146.7	705.6	799.4	93.8	2029	2029	0	Execution Factors
Brant TS M22 Load Relief	Deferred	D-SS-01	3.5	0.0	3.9	0.0	3.9	0.0	-3.9	2025	2033	8	Reprioritization
Chesterville M1 Load Growth	Deferred	D-SS-01	2.9	0.0	3.3	0.0	3.3	3.3	0.0	2025	2033	8	Reprioritization
Dickenson Rd DS F2 + Mount Hope DS Load Relief	Execution	D-SS-01	0.0	3.7	0.0	3.7	1.5	3.7	2.2	2024	2025	1	Execution Factors
Leamington Area DESN5 Feeder Development	Planning	D-SS-01	12.3	0.0	0.0	0.0	51.2	32.2	-19.0	2027	2032	5	Work Definition
South Middle Road TS DESN1 Feeder Development	Execution	D-SS-01	0.8	0.7	18.1	22.3	130.5	141.3	10.8	2025	2025	0	Not a Material Variance
South Middle Road TS DESN2 Feeder Development	Execution	D-SS-01	6.3	17.0	74.1	71.3	74.2	71.3	-2.8	2025	2025	0	Not a Material Variance
Midhurst TS M4-M9 44kV Tie-line	Deferred	D-SS-02	5.4	0.0	5.5	0.0	5.5	6.8	1.3	2025	2031	6	Reprioritization
Stayner TS M2 Tie Line	Deferred	D-SS-02	0.0	0.0	0.0	0.0	4.3	6.0	1.7	2025	2031	6	Reprioritization
ADMS Upgrade - DC 206	Execution	D-SS-Other	0.0	6.2	0.0	0.0	0.0	42.7	42.7	N/A	2028	N/A	Emergent Needs

[6] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

Witness: Gianni Difilippo

Several factors impacted project costs and schedule:

Transmission Driven Emergent Needs: The unanticipated acceleration of transmission projects triggered the relocation of distribution assets. This resulted in distribution line and station relocation projects including Wallaceburg DS Relocation (D-SA-Other), and Enfield TS M4 44kV line relocation (D-SR-10). Hydro One deferred the completion of Leamington Area DESN5 Feeder Development (D-SS-01) to align with Transmission lines and stations investments in the area which must be in place to supply the downstream feeders.

Scope and Schedule Alignment During Detailed Design: As projects moved from early planning stages to detailed design, several incremental scope components leading to increased costs or schedule delays emerged. Vanastra DS Padmount Transformers (D-SR-04) required excess soil remediation and transformer pad re-leveling which resulted in additional efforts and increased construction timeline. Acquiring outstanding easements for Dickenson Rd DS F2 and Mount Hope DS Load Relief (D-SS-01) resulted in schedule delays. Hydro One delayed the Dymond TS M3 Rebuild - Stage 2 (D-SR-10) and brought forward the ADMS Upgrade (D-SS-Other) to address several end-of-life assets in a coordinated manner. This eliminated the need for discrete Outage Response Management System and Distribution Management System upgrades.

AMI 2.0 Project Implementation (D-SR-12): Total costs for the AMI 2.0 project are forecast to be higher than those approved in EB-2021-0110, primarily due to higher-than-estimated IT integration, foundational planning, and program management activities, including contracting, IT assessments, and IT development work associated with the complexities of transitioning from the AMI 1.0 platform to AMI 2.0. As a result of these challenges, the meter and network deployment pilot was delayed to 2025. Consequently, the commencement of mass meter deployment was deferred until the end of 2025, resulting in lower-than-planned ISA amounts for 2025. The total forecast cost estimate reflects updated vendor pricing, refined planning assumptions, actual expenditures incurred from 2021 through 2025, and forecast costs.

Section 2.3

2025 General Plant Capital Performance Report

SECTION 4.9 – ATTACHMENT 4 – CAPITAL PROGRAM PERFORMANCE REPORT FOR GENERAL PLANT – 2025

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Performance Report provides an overview of Hydro One's performance in 2025 in relation to the overall General Plant capital envelope for the year and reviews the performance of individual projects and programs. It addresses both capital expenditures and in-service additions (ISA) delivered by Hydro One, organized as follows:

This report consists of two sections:

- Section 2 presents Transmission-allocated General Plant investments
- Section 3 presents Distribution-allocated General Plant investments

1.2 APPROVED CAPITAL INVESTMENT

In Hydro One's application for Transmission Revenue Requirement and Distribution Rates for 2023 to 2027 (EB-2021-0110), Hydro One reached settlement with all parties (the Settlement Proposal) which was approved by the OEB on November 29, 2022. Under the terms of the Settlement Agreement, the OEB approved Hydro One's 2023 to 2027 capital expenditures and ISA.[1]

In December 2022, Hydro One revised the capital expenditure and ISA forecast on a multi-year envelope and OEB-category basis to implement the OEB-approved Settlement Proposal (the "Forecast"). This was the first time Hydro One allocated the impact of the Settlement Proposal to the project and program level. The Forecast is the basis for the Program and Project level variances described in this Capital Performance Report.

[1] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-255 and p. 257-258.

1.3 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2025 greater than or equal to $3M have been summarized in the tables below along with variance explanations. The thresholds used by Hydro One to identify "material variances" were determined using the following criteria[2]:

- **Cost Variances** – Material cost variances were identified where the in-year variance in cost for programs, or the total project end cost variance is greater than or equal to $1M and greater than or equal to 10% of planned values.
- **Scope Variances** – For programs, material scope variances arise if the functional scope changes by +/-20% or more.
- **Date Variances** – Material date variances were identified for projects where the actual or projected in-service year shifted from 2025 or earlier to a later year.

The variances in these major projects and programs fall mainly into four categories: 1) Emergent Needs, 2) Execution Factors, 3) Work Definition, and 4) Reprioritization. These categories are used to identify the reasons for variances at the project and program level and are further defined below.

Emergent Needs

Emergent needs are investments that Hydro One made in response to a change of priority due to equipment condition or failure, as well as customer needs.

Execution Factors

Execution factors represent advances or delays encountered during the execution phase of work which can include timing changes that arise as a result of changing conditions, risks and priorities that need to be addressed during execution. As risks materialize, plans are adjusted to accommodate the change and mitigate the overall impact to cost, schedule and resources. This can change the year in which the project goes in-service without

[2] This report's variance criteria conform with Hydro One's internal variance reporting criteria which focuses on projects and programs with positive variances greater than the thresholds described below.

necessarily materially changing to the in-service amount or affecting the overall volume of work completed. Some of the main causes of delays are outage deferrals or cancellations, material delivery and logistics factors as well as customer needs.

Work Definition

Work definition variances arise from the process of refining a project's scope, the estimated budget and schedule as the project moves from the high-level planning phase to design and estimate, and execution phases. As the project is refined, there may be increases or decreases to the project cost as a result of new or changing information that becomes known during the design and estimation phase or in the execution stage of work.

Reprioritization

Reprioritization includes investments that are accelerated or deferred. Hydro One adjusts its capital investments through annual planning and in-year redirection processes.

2.0 TRANSMISSION-ALLOCATED GENERAL PLANT INVESTMENTS

2.1 PERFORMANCE AT THE TRANSMISSION GENERAL PLANT CATEGORY

Table 1 below presents a breakdown of the actual 2025 capital expenditures and ISA for the Transmission General Plant category and compares them against OEB-approved values.

Table 1 - 2025 Transmission Capital Expenditures and ISA[3]

OEB Category	Capital Expenditures – 2025			In-Service Additions – 2025		
	OEB-Approved ($M)[4]	Actual ($M)	Variance ($M)	OEB-Approved ($M)	Actual ($M)	Variance ($M)
General Plant – Transmission	111.8	111.0	-0.8	125.7	134.6	8.9

[3] Does not include Hydro One affiliates.
[4] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.254-55 (Table 22 and 23)

In 2025, Hydro One's Transmission-allocated General Plant capital expenditures were 1% below the OEB-approved amount and ISAs were 7% above the OEB-approved amount. As described below, these variances are mainly driven by Information Solutions program variances, including emergent cybersecurity needs, reprioritization of technology investments, and execution factors such as scope refinement and timeline shifts.

2.2 PERFORMANCE AT THE TRANSMISSION PROJECT AND PROGRAM LEVEL

This section presents projects and programs with planned or actual ISA greater than or equal to $3M. A variance category is assigned to any project or program with material variances, as described in Section 1.3. Transmission-allocated General Plant programs are presented below in Table 2 and material projects are presented below in Table 3.

2.2.1 TRANSMISSION PROGRAM PERFORMANCE

Transmission-allocated General Plant Program variances are summarized in Table 2 and further discussed below:

Table 2 - Transmission General Plant Program Summary

			2025 Transmission Capital Expenditures ($M)			2025 Transmission In-Service Additions ($M)			2025 Units[5]				Performance
Category	**EB-2021-0110 ISD Number**	**Program Description**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
Fleet	G-GP-01	Transport and Work Equipment	21.7	22.6	0.9	21.7	22.6	0.9	# of vehicles	407	439	32	Not Applicable
Facilities and Real Estate	G-GP-03	Facilities and Accommodation	8.6	10.1	1.5	30.7	37.8	7.1	N/A	N/A	N/A	N/A	Emergent Needs & Reprioritization
	G-GP-04	Transmission Facilities	13.5	13.6	0.1	16.2	15.7	-0.5	N/A	N/A	N/A	N/A	Not Applicable
Information Solutions	G-GP-05	Hardware/Software Refresh and Maintenance	9.0	8.4	-0.5	6.5	8.0	1.5	N/A	N/A	N/A	N/A	Reprioritization
	G-GP-10	Physical Security Upgrade	8.4	9.9	1.4	0.0	12.9	12.9	N/A	N/A	N/A	N/A	Reprioritization
	G-GP-11	Security Monitoring	1.9	4.1	2.2	1.5	4.4	2.9	N/A	N/A	N/A	N/A	Reprioritization
Operating Infrastructure	G-GP-19	Grid Control Network Sustainment	6.2	7.2	1.0	6.1	4.5	-1.7	N/A	N/A	N/A	N/A	Execution Factors

[5] Where the cost allocation of the program is shared between Transmission and Distribution, the unit numbers reflect the total units allocated to both Transmission and Distribution for the respective investment.

The **Facilities and Accommodation (G-GP-03)** program had capital expenditures that were above the forecast and ISAs that were above forecast. The variance is primarily due to funding reallocation for EV charging stations and substantial completion of various construction projects from prior years.

The **Hardware/Software Refresh and Maintenance (G-GP-05)** program had capital expenditures slightly below the forecast, but within threshold. ISA is slightly above. The variance is a result of reprioritization following shifting program needs, including increased purchase of minor fixed assets to address end of life laptops and tablets,

The **Physical Security Upgrade (G-GP-10)** program's capital expenditures were slightly above the forecast, while ISAs exceeded the forecast. The ISA variance is due to the reprioritization of projects that could be in-serviced within the same year as construction. The plan was adjusted, and included the opportunity to leverage concurrent construction activities in the same region.

The **Security Monitoring (G-GP-11)** program had capital expenditures and ISAs that were slightly above the forecast due to reprioritization and timing differences in the delivery of planned work for application rationalization and to reduce reliance on legacy systems and improve operational efficiency for Avesksa (Sailpoint).

The Grid Control Network Sustainment (G-GP-19) program had capital expenditures that were above the forecast and the ISAs that were below forecast. The variance was due to the completion of work deferred from earlier periods, together with ongoing manufacturer equipment delivery delays and resource constraints that affected the timing of planned in-service additions.

2.2.2 TRANSMISSION PROJECT PERFORMANCE

Transmission-allocated General Plant Project variances are summarized in Table 3 and further discussed below:

Table 3 - Transmission General Plant Project Summary

				2025 Transmission Capital Expenditures ($M)		2025 Transmission In-Service Additions ($M)		Project End Total Cost ($M)[6]			In-Service Year			Performance
Functional Area / Project Name	**Allocation**	**Project Phase[7]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance (Years)**	**Variance Category**
System Operations														
UWPC Forms Package	Shared	Execution	G-GP-Other	1.1	0.2	3.0	0.0	7.0	11.0	4.0	2025	2027	2	Execution Factors

[6] Where the cost allocation of the project is shared, the project total reflects the total value allocated to both Transmission and Distribution for the respective investment.
[7] Phases: Planning, Execution, Complete, Cancelled, or Deferred.

The UWPC Forms Package Replacement projects (G-GP-Other) had project end actual/latest forecast is higher forecast primarily due to timing impacts and scope refinement during project execution. Implementation activities were deferred pending completion of a dependent ITOA (Integrated Tools for Operations Application) platform migration, resulting in the project in-service date being delayed later than originally planned. In addition, detailed design and requirements validation identified the need for expanded functionality, including electronic logging and control room resource scheduling capabilities, which increased the overall project scope and associated expenditures.

3.0 DISTRIBUTION-ALLOCATED GENERAL PLANT INVESTMENTS

3.1 PERFORMANCE AT THE DISTRIBUTION GENERAL PLANT CATEGORY

Table 4 below presents a breakdown of the actual 2025 capital expenditures and ISA for the Distribution General Plant category and compares them against the OEB-approved values.

Table 4 - 2025 Distribution Capital Expenditures and ISA[8]

OEB Category	Capital Expenditures – 2025			In-Service Additions – 2025		
	OEB-Approved ($M)[9]	Actual ($M)	Variance ($M)	OEB-Approved ($M)	Actual ($M)	Variance ($M)
General Plant - Distribution	149.5	118.7	-30.7	193.7	195.2	1.6

In 2025, Hydro One's Distribution-allocated General Plant capital expenditures were 21% below the OEB-approved amount and ISAs were 1% above the OEB-approved amount. As described below, these variances are mainly driven by Information Solutions and System Operations project variances, including emergent cybersecurity needs and reprioritization of digital investments.

[8] Does not include Hydro One affiliates.
[9] EB-2021-0110, Decision and Order, November 29, 2022, Schedule A, p.257-58 (Table 25 and 26)

3.2 PERFORMANCE AT THE DISTRIBUTION PROJECT AND PROGRAM LEVEL

This section presents projects and programs with planned or actual ISA greater than or equal to $3M. A variance category is assigned to any project or program with material variances, as described in Section 1.3. Distribution-allocated General Plant programs are presented below in Table 5 and material projects are presented below in Table 6.

3.2.1 DISTRIBUTION PROGRAM PERFORMANCE

Distribution-allocated General Plant Program variances are summarized in Table 5 and further discussed below:

Table 5 - Distribution General Plant Program Summary

			2025 Distribution Capital Expenditures ($M)			2025 Distribution In-Service Additions ($M)			2025 Units[10]				Performance
Category	**EB-2021-0110 ISD Number**	**Program Description**	**Forecast**	**Actual**	**Variance**	**Forecast**	**Actual**	**Variance**	**Unit Description**	**Forecast**	**Actual**	**Variance**	**Variance Category**
Fleet	G-GP-01	Transport and Work Equipment	42.6	44.2	1.7	42.6	44.2	1.7	# of vehicles	407	439	32	Not Applicable
	G-GP-02	Helicopters	4.0	5.2	1.2	4.0	5.2	1.2	# of helicopters	1	1	0	Execution Factors
Facilities and Real Estate	G-GP-03	Facilities and Accommodation	49.5	29.9	-19.6	135.3	99.6	-35.7	N/A	N/A	N/A	N/A	Emergent Needs & Reprioritization
Information Solutions	G-GP-05	Hardware/Software Refresh and Maintenance	14.4	13.3	-1.1	11.0	12.7	1.7	N/A	N/A	N/A	N/A	Reprioritization
	G-GP-11	Security Monitoring	1.2	5.6	4.4	0.6	6.0	5.4	N/A	N/A	N/A	N/A	Reprioritization
System Operations	G-GP-12	Common Operating Technology Infrastructure	2.9	3.5	0.6	3.0	3.5	0.5	N/A	N/A	N/A	N/A	Not Applicable

[10] Where the cost allocation of the program is shared between Transmission and Distribution, the unit numbers reflect the total units allocated to both Transmission and Distribution for the respective investment.

The **Helicopters (G-GP-02)** program had capital expenditures and ISAs that were above the forecast. The higher-than-expected spending was primarily driven by foreign exchange rate impacts.

The **Facilities and Real Estate (G-GP-03)** program had capital expenditures and ISAs that were lower than forecast. These variances were mainly driven by timing of execution of various construction projects.

The **Hardware/Software Refresh and Maintenance (G-GP-05)** program had capital expenditures and ISAs that were below the forecast. Please see the explanation provided in Section 2.2.1.

The **Security Monitoring (G-GP-11)** program had capital expenditures and ISAs that were above the forecast. Please see the explanation provided in Section 2.2.1.

3.2.2 DISTRIBUTION PROJECT PERFORMANCE

Distribution-allocated General Plant Project variances are summarized in Table 6 and further discussed below:

Table 6 - Distribution General Plant Project Summary

				2025 Distribution Capital Expenditures ($M)		2025 Distribution In-Service Additions ($M)		Project End Total Cost ($M)[11]			In-Service Year			Performance
Functional Area / Project Name	**Allocation**	**Project Phase[12]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Project Total Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Variance Category**
Information Solutions														
Windows 11 Deployment	Shared	Execution	G-GP-Other	0.0	2.7	0.0	3.2	0.0	5.6	5.6	-	2026	-	Emergent Needs
System Operations														
UWPC Forms Package	Shared	Execution	G-GP-Other	1.4	0.3	4.0	0.0	7.0	11.0	4.0	2025	2027	2	Execution Factors

[11] Where the cost allocation of the project is shared, the project total reflects the total value allocated to both Transmission and Distribution for the respective investment.
[12] Phases: Planning, Executing, Complete, Cancelled, or Deferred.

The Windows 11 Deployment (G-GP-Other) had expenditures above the forecast due to Microsoft's announcement of the end of support for Windows 10 effective October 14, 2025, after the 2023-2027 Plan was established. As a result, Hydro One had to deploy Windows 11 across its user base to maintain vendor support, security updates, and compatibility with enterprise applications and security standards.

The UWPC Forms Package Replacement projects had lower expenditures and ISA than planned for 2025. Please see the explanation provided in Section 2.2.2.

This page has been left blank intentionally.

Section 3.1

DERs Connected to Hydro One's Distribution System (per undertaking JT-3.22)

Number and MW of Behind the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2025

The breakdown of behind-the-meter Distributed Energy Resources (BTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission connected station as of December 31, 2025, is as follows:

*Ct=Count, Cap=Capacity

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
AGUASABON DS	25	0.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	25	0.21
ALLANBURG TS	7	1.78	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	1.78
ALLISTON TS	70	0.81	0	0.00	0	0.00	0	0.00	0	0.00	2	18.24	72	19.05
ALMONTE TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	9	0.09	14	0.13
ARDOCH DS	27	0.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	27	0.21
ARMITAGE TS DESN1	37	0.97	0	0.00	0	0.00	0	0.00	0	0.00	1	0.50	38	1.47
ARMITAGE TS DESN2	61	0.88	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	61	0.88
ARNPRIOR TS	52	0.56	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	57	0.61
AWENDA DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
AYLMER TS	7	0.06	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	8	0.07
BARWICK TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
BARRIE TS	1	0.20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.20
BATTERSEA DS	17	0.17	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.17
BEAMSVILLE TS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
BEAVERTON TS	54	0.58	1	0.00	0	0.00	0	0.00	0	0.00	1	0.01	56	0.59
BELLE RIVER TS	14	0.14	1	0.01	0	0.00	0	0.00	0	0.00	1	0.03	16	0.17
BELLEVILLE TS	70	1.60	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	70	1.60

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
BILBERRY CREEK TS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
BIRCH TS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	3.98	2	3.98
BLOOMSBURG DS	36	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	36	0.36
BRACEBRIDGE TS	7	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.06
BRANT TS	22	0.19	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02	24	0.21
BRANTFORD TS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
BROCKVILLE TS	69	1.95	0	0.00	0	0.00	0	0.00	0	0.00	3	3.60	72	5.55
BROWN HILL TS	83	0.71	2	0.01	0	0.00	0	0.00	0	0.00	2	0.64	87	1.36
BUCHANAN TS	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	3	14.27	9	14.33
BURLEIGH DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
CALEDONIA TS	26	0.26	4	0.01	0	0.00	0	0.00	0	0.00	2	4.00	32	4.28
CENTRALIA TS	26	1.71	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	31	1.76
CHAPLEAU DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	1.80	1	1.80
CHERRYWOOD TS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.75	1	0.75
CHESTERVILLE TS	32	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	32	0.36
CLARABELLE TS	20	0.30	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	20	0.30
CLARENCE DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
CLARKE TS	24	0.64	0	0.00	0	0.00	0	0.00	0	0.00	4	10.46	28	11.10
CLEARWATER BAY DS	6	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.05
COBDEN DS	7	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.07
COBDEN TS	28	0.20	0	0.00	0	0.00	0	0.00	0	0.00	14	0.14	42	0.34
COCHRANE WEST DS	8	0.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.31
COMMERCE WAY TS	21	0.69	0	0.00	0	0.00	0	0.00	0	0.00	2	6.10	23	6.79
CONSTANCE DS	10	0.29	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02	12	0.31

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
CRAIG DS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
CRAWFORD TS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.79	1	0.79
CROSBY TS DESN1	19	0.26	1	0.00	0	0.00	0	0.00	0	0.00	5	0.05	25	0.31
CROWLAND TS	9	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.07
CRYSTAL FALLS TS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
CUMBERLAND DS	15	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.14
DES JOACHIMS DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	3	0.03
DOBBIN DS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
DOBBIN TS	75	0.78	0	0.00	0	0.00	0	0.00	0	0.00	1	2.50	76	3.28
DOUGLAS POINT TS	37	1.09	1	0.25	0	0.00	0	0.00	0	0.00	0	0.00	38	1.34
DRYDEN TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
DUART TS DESN1	12	0.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.34
DUNDAS TS	43	0.74	0	0.00	0	0.00	0	0.00	0	0.00	3	0.23	46	0.97
DUNDAS TS #2	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
DUNNVILLE TS	25	0.36	0	0.00	0	0.00	0	0.00	0	0.00	3	0.04	28	0.41
DYMOND TS	5	0.07	0	0.00	0	0.00	0	0.00	0	0.00	2	3.07	7	3.13
EDGEWARE TS	55	0.98	0	0.00	0	0.00	0	0.00	0	0.00	3	11.10	58	12.08
ELMIRA TS	2	0.05	0	0.00	0	0.00	0	0.00	0	0.00	1	2.30	3	2.35
ENFIELD TS DESN 1	17	0.17	0	0.00	0	0.00	0	0.00	0	0.00	1	0.52	18	0.69
ESPANOLA TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
ETON DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
EVERETT TS	19	0.34	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	20	0.35
FAUQUIER DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
FERGUS TS	129	2.28	0	0.00	0	0.00	0	0.00	0	0.00	2	0.04	131	2.32
FOREST JURA DS	25	0.87	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	25	0.87
FOREST LEA DS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.08

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
FRONTENAC TS	52	0.65	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	52	0.65
GALT TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
GODERICH TS	7	0.18	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	8	0.19
GRAND BEND EAST DS	7	0.11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.11
GREELY DS	40	0.39	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	40	0.39
HANOVER TS	92	1.30	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	92	1.30
HARROWSMITH DS	26	0.22	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	26	0.22
HAVELOCK TS	45	0.37	0	0.00	0	0.00	0	0.00	0	0.00	7	4.06	52	4.43
HAWTHORNE TS	48	0.67	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	48	0.67
HEARST TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
HERRIDGE LAKE DS	2	0.15	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	5	0.18
HIGHBURY TS	13	0.23	0	0.00	0	0.00	0	0.00	0	0.00	2	6.00	15	6.22
HINCHINBROOKE DS	5	0.03	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	10	0.08
HOLLAND TS	16	0.37	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.37
HOYLE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
INGERSOLL TS	36	1.51	0	0.00	0	0.00	0	0.00	0	0.00	14	0.14	50	1.65
JARVIS TS	21	0.55	2	0.01	0	0.00	0	0.00	0	0.00	4	0.03	27	0.59
KAPUSKASING TS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	1	0.16	4	0.18
KEEWATIN DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
KEITH TS DESN1	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	3.40	1	3.40
KENORA DS	17	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.14
KENT TS DESN1	17	0.37	0	0.00	0	0.00	0	0.00	0	0.00	1	5.00	18	5.37
KENT TS DESN2	5	0.13	0	0.00	0	0.00	0	0.00	0	0.00	3	2.40	8	2.53
KINGSTON GARDINER TS DESN1	58	0.49	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	58	0.49

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
KINGSTON GARDINER TS DESN2	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	2	16.80	3	16.81
KINGSVILLE TS	20	0.41	0	0.00	0	0.00	0	0.00	0	0.00	1	0.82	21	1.23
KIRKLAND LAKE TS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
KLEINBURG TS	62	0.86	1	0.01	0	0.00	0	0.00	0	0.00	4	4.63	67	5.50
LAFOREST ROAD DS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
LAMBTON TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
LARCHWOOD TS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04	13	0.12
LAUZON TS DESN1	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.95	1	0.95
LAUZON TS DESN2	6	0.31	0	0.00	0	0.00	0	0.00	0	0.00	1	0.75	7	1.06
LDC Owned Station	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.06
LEAMINGTON TS DESN 1	12	0.32	0	0.00	0	0.00	0	0.00	0	0.00	1	10.00	13	10.32
LEAMINGTON TS DESN 2	2	0.51	0	0.00	0	0.00	0	0.00	0	0.00	1	0.82	3	1.33
LINDSAY TS	42	1.50	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05	47	1.55
LODGEROOM DS	15	0.18	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.18
LONGLAC TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
LONGUEUIL TS	40	0.89	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	40	0.89
LONGWOOD TS	41	0.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	41	0.51
MALDEN TS	8	0.07	0	0.00	0	0.00	0	0.00	0	0.00	1	9.20	9	9.27
MANITOULIN TS	32	0.80	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	33	0.81
MANOTICK DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
MARATHON DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
MARGACH DS	15	0.12	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	16	0.13
MARIONVILLE DS	13	0.20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.20

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
MARTINDALE TS	27	0.24	0	0.00	0	0.00	0	0.00	0	0.00	7	0.07	34	0.30
MASSEY DS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
MATTAWA DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	3	0.03
MAZINAW DS	72	0.67	0	0.00	0	0.00	0	0.00	0	0.00	1	2.99	73	3.66
MEAFORD TS	50	0.55	0	0.00	0	0.00	0	0.00	0	0.00	3	0.77	53	1.32
MIDHURST TS DESN1	67	0.58	1	0.00	0	0.00	0	0.00	1	0.04	0	0.00	69	0.62
MINAKI DS	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.00
MINDEN TS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	30	0.30	39	0.38
MONTEITH DS	15	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.14
MORRISBURG TS	8	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.07
MURILLO DS	78	1.13	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	81	1.16
MUSKOKA TS	48	0.47	0	0.00	0	0.00	0	0.00	0	0.00	29	0.29	77	0.76
NAPANEE TS	13	0.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.51
NAVAN DS	33	0.39	0	0.00	0	0.00	0	0.00	0	0.00	2	5.25	35	5.64
NEBO TS DESN1	10	0.32	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	10	0.32
NESTOR FALLS DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
NEWINGTON DS	23	0.42	0	0.00	0	0.00	0	0.00	0	0.00	1	0.75	24	1.17
NORFOLK TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
NORTHBROOK DS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
ORANGEVILLE TS DESN1	4	0.13	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02	6	0.15
ORANGEVILLE TS DESN2	129	1.64	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	130	1.65
ORILLIA TS	63	0.58	0	0.00	0	0.00	0	0.00	0	0.00	4	3.28	67	3.87
ORLEANS TS	39	0.41	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	39	0.41
OTONABEE TS DESN1	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04	13	0.12

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
OTONABEE TS DESN2	70	1.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	70	1.01
OWEN SOUND TS	229	2.27	1	0.00	0	0.00	0	0.00	0	0.00	0	0.00	230	2.27
PALMERSTON TS	61	2.28	0	0.00	0	0.00	0	0.00	0	0.00	1	0.13	62	2.41
PARRY SOUND TS	50	0.41	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	51	0.42
PEMBROKE TS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
PETAWAWA DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	2	3.05	5	3.08
PIC DS	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01
PICTON TS	95	0.91	1	0.08	0	0.00	0	0.00	0	0.00	0	0.00	96	0.99
PLEASANT TS DESN1	5	0.03	0	0.00	0	0.00	0	0.00	0	0.00	1	0.95	6	0.98
PORT ARTHUR TS #1	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04	9	0.09
PORT HOPE TS DESN1	64	2.17	0	0.00	0	0.00	0	0.00	0	0.00	1	3.00	65	5.17
PUSLINCH DS	37	0.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	37	0.35
RAMORE TS	3	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.19
RED LAKE TS	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01
ROCKLAND DS	6	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.05
ROCKLAND EAST DS	17	0.22	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	18	0.23
RUSSELL DS	7	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.06
SAM LAKE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
SAPAWE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
SCHREIBER WINNIPG DS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
SEAFORTH TS	16	1.01	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	17	1.02
SHARBOT DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
SIDNEY TS	53	0.44	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	53	0.44

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
SIOUX NARROWS DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
SMITHS FALLS TS	114	1.68	0	0.00	0	0.00	0	0.00	0	0.00	66	1.87	180	3.55
SOUTH GLOUCESTER DS	6	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.05
SOUTH MARCH TS	38	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	38	0.36
SOWERBY DS	2	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.01
SPANISH DS	3	0.18	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.18
ST ISIDORE TS	38	2.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	38	2.19
ST LAWRENCE TS	24	0.22	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	24	0.22
ST MARYS TS	10	0.45	0	0.00	0	0.00	0	0.00	0	0.00	1	1.76	11	2.20
STAYNER TS	72	0.83	0	0.00	0	0.00	0	0.00	0	0.00	3	11.16	75	11.99
STEWARTVILLE TS	27	0.22	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	28	0.23
STRATFORD TS	34	1.79	0	0.00	0	0.00	0	0.00	0	0.00	3	4.51	37	6.29
STRATHROY TS	6	0.29	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.29
STRIKER DS	4	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.08
TEMAGAMI DS	0	0.00	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
THOROLD TS	5	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.09
TILBURY WEST DS	6	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.14
TILLSONBURG TS	42	0.90	0	0.00	0	0.00	0	0.00	0	0.00	26	1.07	68	1.97
TIMMINS TS	1	0.07	0	0.00	0	0.00	0	0.00	0	0.00	1	1.57	2	1.65
TROUT LAKE TS	33	0.29	0	0.00	0	0.00	0	0.00	0	0.00	73	0.73	106	1.02
VERMILION BAY DS	2	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.09
VERNER DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
WALLACE TS	32	0.24	0	0.00	0	0.00	0	0.00	0	0.00	47	0.47	79	0.71
WALLACEBURG TS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
WANSTEAD TS	4	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.07

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
WARREN DS	3	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.02
WAUBAUSHENE TS	53	0.41	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	53	0.41
WENDOVER DS	21	0.44	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	21	0.44
WHARNCLIFFE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	2	0.02
WHITEFISH DS	14	0.12	0	0.00	0	0.00	0	0.00	0	0.00	11	0.11	25	0.23
WILHAVEN DS	11	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.19
WILSON TS DESN2	37	16.03	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	38	16.04
WINGHAM TS	24	0.76	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	24	0.76
WOLVERTON DS	17	0.26	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	20	0.29
WONDERLAND TS	8	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.08
WOODSTOCK TS	28	1.58	0	0.00	0	0.00	0	0.00	0	0.00	2	1.01	30	2.59
SHABAQUA DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	1	0.01
SHARBOT DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03	3	0.03

Notes on Data

- The BTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only DERs directly connected to Hydro One's network are included. DERs that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.
- The list only consists of BTM DER Resources that Hydro One has records of. There may be BTM DERs that are utilized by customers for their own purposes (e.g. backup diesel generation in mines). As customers have no obligation to inform Hydro One of these installations, these installations are neither tracked nor included in this list.

Number and MW of Front of the Meter Distributed Energy Resources Connected to Hydro One Feeders by Fuel Type - 2025

The breakdown of front-of-the-meter Distributed Energy Resources (FTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission connected station as of December 31, 2025, is as follows:

*Ct=Count, Cap=Capacity

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
AGIMAK DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
AGUASABON DS	6	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.09
ALLANBURG TS	70	1.40	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	70	1.40
ALLISTON TS	41	1.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	41	1.06
ALMONTE TS	112	21.82	1	0.01	0	0.00	0	0.00	0	0.00	1	5.00	114	26.83
ARDOCH DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
ARMITAGE TS DESN1	73	7.24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	73	7.24
ARMITAGE TS DESN2	93	1.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	93	1.31
ARNPRIOR TS	119	22.23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	119	22.23
AYLMER TS	50	2.48	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	50	2.48
BALLINAFAD MS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
BARWICK TS	103	25.99	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	103	25.99
BATTERSEA DS	70	1.24	0	0.00	1	0.25	2	1.00	0	0.00	0	0.00	73	2.49
BEAMSVILLE TS	7	0.07	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.07
BEARDMORE DS #2	0	0.00	0	0.00	0	0.00	0	0.00	1	6.00	0	0.00	1	6.00
BEAVERTON TS	300	57.72	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	300	57.72
BELLE RIVER TS	167	2.87	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	168	12.87

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
BELLEVILLE TS	205	52.76	0	0.00	1	0.25	1	0.50	0	0.00	0	0.00	207	53.51
BILBERRY CREEK TS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
BLOOMSBURG DS	17	13.24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	13.24
BRACEBRIDGE TS	15	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.14
BRANT TS	107	9.70	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	107	9.70
BRANTFORD TS	11	0.11	0	0.00	0	0.00	0	0.00	0	0.00	1	8.10	12	8.21
BROCKVILLE TS	219	32.53	0	0.00	0	0.00	1	0.50	0	0.00	1	9.50	221	42.53
BROWN HILL TS	212	32.97	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	212	32.97
BUCHANAN TS	14	0.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	14	0.34
BUNTING TS	0	0.00	0	0.00	0	0.00	0	0.00	2	4.00	0	0.00	2	4.00
BURLEIGH DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
CALEDONIA TS	31	20.95	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	31	20.95
CALSTOCK DS	8	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.08
CAMPBELL TS DESN2	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
CENTRALIA TS	145	5.16	0	0.00	0	0.00	2	0.50	0	0.00	0	0.00	147	5.66
CHESTERVILLE TS	100	21.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	100	21.35
CLARABELLE TS	79	2.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	79	2.51
CLARENCE DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
CLARKE TS	63	1.38	0	0.00	1	0.30	3	0.75	0	0.00	0	0.00	67	2.43
CLEARWATER BAY DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
COBDEN DS	37	0.36	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	37	0.36

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
COBDEN TS	137	4.45	0	0.00	1	0.50	0	0.00	0	0.00	0	0.00	138	4.95
COCHRANE WEST DS	19	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	19	0.19
COMMERCE WAY TS	94	2.90	1	18.00	0	0.00	0	0.00	0	0.00	0	0.00	95	20.90
CONSTANCE DS	97	1.44	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	97	1.44
CRAIG DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
CRILLY DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
CROSBY TS	5	40.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	40.01
CROSBY TS DESN1	49	21.89	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	49	21.89
CROWLAND TS	14	0.27	1	9.00	0	0.00	0	0.00	0	0.00	0	0.00	15	9.27
CRYSTAL FALLS TS	43	5.62	0	0.00	0	0.00	0	0.00	3	11.50	0	0.00	46	17.12
CUMBERLAND DS	21	0.39	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	21	0.39
DEEP RIVER DS	15	0.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.28
DES JOACHIMS DS	3	0.26	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.26
DOBBIN DS	24	0.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	24	0.34
DOBBIN TS	189	14.12	1	10.00	0	0.00	1	0.10	0	0.00	0	0.00	191	24.22
DOUGLAS POINT TS	117	2.10	3	11.05	0	0.00	0	0.00	0	0.00	0	0.00	120	13.15
DRYDEN TS	31	10.28	0	0.00	0	0.00	0	0.00	0	0.00	2	0.38	33	10.66
DUART TS DESN1	103	10.91	1	10.00	0	0.00	1	0.25	0	0.00	0	0.00	105	21.16
DUNDAS TS	210	4.89	0	0.00	0	0.00	0	0.00	0	0.00	2	8.49	212	13.38
DUNNVILLE TS	23	0.67	2	9.90	0	0.00	0	0.00	0	0.00	2	10.42	27	20.99

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
DYMOND TS	59	9.92	0	0.00	0	0.00	0	0.00	1	9.50	0	0.00	60	19.42
EAR FALLS TS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
EDGEWARE TS	107	3.77	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	107	3.77
ELLIOT LAKE TS	14	0.20	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	14	0.20
ELMIRA TS	24	0.35	0	0.00	0	0.00	1	0.25	0	0.00	0	0.00	25	0.60
ENFIELD TS DESN 1	92	1.56	4	35.85	0	0.00	0	0.00	0	0.00	0	0.00	96	37.41
ESPANOLA TS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
ETON DS	29	0.33	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	29	0.33
EVERETT TS	106	1.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	106	1.10
FALLOWFIELD DS	0	0.00	0	0.00	1	5.55	0	0.00	0	0.00	0	0.00	1	5.55
FAUQUIER DS	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.06
FERGUS TS	198	3.01	3	41.20	0	0.00	1	0.14	0	0.00	0	0.00	202	44.35
FOREST JURA DS	98	1.38	2	16.50	0	0.00	0	0.00	0	0.00	0	0.00	100	17.88
FOREST LEA DS	12	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.12
FRONTENAC TS	130	2.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	130	2.31
GALT TS	16	0.15	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.15
GODERICH TS	79	1.15	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	79	1.15
GRAND BEND EAST DS	42	1.01	1	0.80	2	1.00	0	0.00	0	0.00	0	0.00	45	2.81
GREELY DS	67	1.61	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	67	1.61
HANOVER TS	362	8.88	1	22.17	0	0.00	3	0.75	2	0.28	0	0.00	368	32.08
HARROWSMITH DS	139	1.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	139	1.28

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
HAVELOCK TS	242	12.11	0	0.00	0	0.00	0	0.00	1	18.00	0	0.00	243	30.11
HAWTHORNE TS	82	11.75	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	82	11.75
HEARST TS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
HERRIDGE LAKE DS	4	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.04
HIGHBURY TS	35	7.49	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	35	7.49
HINCHINBROOK E DS	39	0.58	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	39	0.58
HOLLAND TS	76	2.45	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	76	2.45
INGERSOLL TS	133	21.83	0	0.00	0	0.00	3	0.75	0	0.00	1	0.25	137	22.83
Innisfil MS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
IROQUOIS FALLS DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
JARVIS TS	33	4.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	33	4.21
KAPUSKASING TS	64	8.64	0	0.00	0	0.00	0	0.00	4	22.00	0	0.00	68	30.64
KEITH TS DESN1	6	20.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	20.04
KENORA DS	15	0.15	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	15	0.15
KENT TS DESN1	178	2.63	3	30.00	0	0.00	0	0.00	0	0.00	0	0.00	181	32.63
KENT TS DESN2	125	1.25	2	20.00	0	0.00	0	0.00	0	0.00	0	0.00	127	21.25
KINGSTON GARDINER TS DESN1	147	42.35	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	148	52.35
KINGSTON GARDINER TS DESN2	34	0.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	34	0.62
KINGSVILLE TS	191	3.00	3	25.80	0	0.00	0	0.00	0	0.00	1	12.00	195	40.80

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
KIRKLAND LAKE TS	34	8.51	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	34	8.51
KLEINBURG TS	172	3.63	0	0.00	0	0.00	0	0.00	0	0.00	1	3.23	173	6.86
LAFOREST ROAD DS	1	0.01	0	0.00	0	0.00	0	0.00	1	14.00	0	0.00	2	14.01
LAMBTON TS	42	40.61	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	42	40.61
LARCHWOOD TS	34	0.86	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	34	0.86
LAUZON TS DESN1	3	0.23	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.23
LAUZON TS DESN2	149	2.60	2	20.00	1	0.25	0	0.00	0	0.00	0	0.00	152	22.85
LDC Owned Station	11	0.11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.11
LEAMINGTON TS DESN 1	163	3.49	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	163	3.49
LEAMINGTON TS DESN 2	42	0.85	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	42	0.85
LINDSAY TS	232	45.60	0	0.00	1	0.50	0	0.00	1	0.50	1	0.34	235	46.94
LODGEROOM DS	67	1.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	67	1.10
LONGLAC TS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
LONGUEUIL TS	144	51.57	1	0.01	3	0.46	0	0.00	0	0.00	0	0.00	148	52.04
LONGWOOD TS	158	3.33	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	158	3.33
MALDEN TS	109	12.39	3	29.80	0	0.00	0	0.00	0	0.00	0	0.00	112	42.19
MANITOULIN TS	101	0.95	2	5.60	0	0.00	0	0.00	0	0.00	0	0.00	103	6.55
MANITOUWADGE DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
MANITOUWADGE TS	3	0.03	0	0.00	2	13.00	0	0.00	0	0.00	0	0.00	5	13.03

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
MANOTICK DS	18	0.46	0	0.00	0	0.00	1	0.50	0	0.00	0	0.00	19	0.96
MARATHON DS	17	0.13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.13
MARGACH DS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
MARIONVILLE DS	64	0.62	0	0.00	0	0.00	1	0.25	0	0.00	1	0.50	66	1.37
MARTINDALE TS	47	10.91	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	47	10.91
MASSEY DS	13	0.13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.13
MATTAWA DS	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
MAZINAW DS	12	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.10
MEAFORD TS	64	1.16	1	18.00	0	0.00	0	0.00	0	0.00	0	0.00	65	19.16
MIDHURST TS DESN1	242	37.89	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	242	37.89
MINDEN TS	86	2.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	86	2.28
MONTEITH DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
MORRISBURG TS	115	20.73	1	30.00	0	0.00	0	0.00	0	0.00	0	0.00	116	50.73
MOUNTAIN CHUTE DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
MURILLO DS	100	1.21	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	100	1.21
MUSKOKA TS	222	29.07	0	0.00	0	0.00	0	0.00	1	5.00	0	0.00	223	34.07
NAKINA DS	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	1.50	1	1.50
NAPANEE TS	231	60.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	231	60.35
NAVAN DS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
NEBO TS DESN1	90	1.06	0	0.00	1	3.20	0	0.00	0	0.00	0	0.00	91	4.26
NESTOR FALLS DS	13	0.12	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.12
NEWINGTON DS	9	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.10

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
NIPIGON DS	2	0.02	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	2	0.02
NORFOLK TS	131	11.13	2	19.90	0	0.00	0	0.00	0	0.00	1	8.50	134	39.53
NORTH BAY TS	1	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.08
NORTH SHORE DS	17	0.16	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	17	0.16
NORTHBROOK DS	31	0.52	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	31	0.52
ORANGEVILLE TS DESN1	3	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	3	0.03
ORANGEVILLE TS DESN2	361	5.44	5	44.23	0	0.00	0	0.00	0	0.00	0	0.00	366	49.67
ORILLIA TS	183	31.84	0	0.00	0	0.00	0	0.00	1	1.65	1	1.06	185	34.55
ORLEANS TS	71	3.10	0	0.00	0	0.00	0	0.00	0	0.00	1	1.00	72	4.10
OTONABEE TS DESN1	17	2.34	0	0.00	1	1.60	0	0.00	0	0.00	0	0.00	18	3.94
OTONABEE TS DESN2	235	9.24	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	235	9.24
OWEN SOUND TS	370	10.62	0	0.00	1	0.10	0	0.00	0	0.00	0	0.00	371	10.72
PALMERSTON TS	256	4.76	1	0.50	0	0.00	0	0.00	0	0.00	0	0.00	257	5.26
PARRY SOUND TS	57	3.63	0	0.00	0	0.00	0	0.00	0	0.00	1	2.00	58	5.63
PEMBROKE TS	33	0.59	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	33	0.59
PETAWAWA DS	12	0.11	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	12	0.11
PIC DS	11	0.10	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	11	0.10
PICTON TS	218	28.78	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	218	28.78
PLEASANT TS DESN1	23	0.31	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	23	0.31

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
PORT ARTHUR TS #1	30	0.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	30	0.28
PORT COLBORNE TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
PORT HOPE TS DESN1	237	34.97	0	0.00	1	0.01	0	0.00	0	0.00	1	5.00	239	39.98
PUSLINCH DS	96	1.60	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	96	1.60
RAMORE TS	12	8.11	0	0.00	0	0.00	0	0.00	1	0.52	0	0.00	13	8.63
RED LAKE TS	5	0.04	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.04
RED ROCK DS	29	1.28	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	29	1.28
ROCKLAND DS	5	0.05	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	5	0.05
ROCKLAND EAST DS	14	0.14	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	14	0.14
RUSSELL DS	7	0.13	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	7	0.13
SCHREIBER WINNIPG DS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.08
SEAFORTH TS	102	2.61	1	15.00	0	0.00	0	0.00	0	0.00	0	0.00	103	17.61
SHABAQUA DS	9	0.09	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.09
SHARBOT DS	22	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	22	0.19
SIDNEY TS	246	4.04	0	0.00	0	0.00	0	0.00	1	10.00	0	0.00	247	14.04
SIOUX NARROWS DS	4	0.03	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	4	0.03
SMITHS FALLS TS	256	83.34	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	256	83.34
SOUTH GLOUCESTER DS	13	0.16	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	13	0.16
SOUTH MARCH TS	66	1.28	0	0.00	0	0.00	0	0.00	0	0.00	1	6.40	67	7.68

Witness: Peter Faltaous

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
SOUTH MIDDLE ROAD TS	9	0.09	0	0.00	0	0.00	0	0.00	0	0.00	1	13.33	10	13.42
SOWERBY DS	9	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	9	0.08
SPANISH DS	6	0.06	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	6	0.06
ST ISIDORE TS	162	23.10	0	0.00	2	4.70	5	1.22	0	0.00	0	0.00	169	29.03
ST LAWRENCE TS	80	81.25	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	80	81.25
ST MARYS TS	51	1.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	51	1.19
STAYNER TS	199	6.12	2	28.45	0	0.00	0	0.00	0	0.00	0	0.00	201	34.57
STEWARTVILLE TS	83	4.35	0	0.00	0	0.00	0	0.00	1	10.70	0	0.00	84	15.05
STRATFORD TS	170	1.98	0	0.00	0	0.00	3	1.10	0	0.00	0	0.00	173	3.08
STRATHROY TS	59	14.58	1	4.10	0	0.00	0	0.00	0	0.00	0	0.00	60	18.68
STRIKER DS	60	2.54	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	60	2.54
TEMAGAMI DS	1	0.01	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01
THOROLD TS	30	0.26	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	30	0.26
TILBURY WEST DS	48	0.57	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	49	10.57
TILLSONBURG TS	165	2.01	2	19.80	0	0.00	0	0.00	0	0.00	0	0.00	167	21.81
TIMMINS TS	4	0.04	0	0.00	0	0.00	0	0.00	2	20.50	0	0.00	6	20.54
TROUT LAKE TS	87	2.35	0	0.00	0	0.00	0	0.00	2	10.80	0	0.00	89	13.15
VERMILION BAY DS	8	0.08	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	8	0.08
VERNER DS	31	0.64	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	31	0.64
WALLACE TS	100	0.97	0	0.00	0	0.00	0	0.00	1	0.60	0	0.00	101	1.57

	Solar		Wind		Biomass		Biogas		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Grand Total	
Station Name	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**	**Ct**	**Cap (MW)**
WALLACEBURG TS	175	1.72	1	10.00	0	0.00	0	0.00	0	0.00	1	5.16	177	16.88
WANSTEAD TS	185	3.48	1	10.00	0	0.00	0	0.00	0	0.00	0	0.00	186	13.48
WARREN DS	16	0.71	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.71
WAUBAUSHENE TS	143	43.69	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	143	43.69
WENDOVER DS	62	13.11	0	0.00	0	0.00	1	0.50	0	0.00	0	0.00	63	13.61
WHARNCLIFFE DS	18	0.18	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	18	0.18
WHITEFISH DS	16	0.62	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	16	0.62
WILHAVEN DS	21	0.19	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	21	0.19
WILSON TS DESN2	142	21.96	0	0.00	0	0.00	0	0.00	1	0.01	1	19.40	144	41.37
WINGHAM TS	130	1.98	1	18.00	0	0.00	0	0.00	0	0.00	0	0.00	131	19.98
WOLVERTON DS	61	1.35	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	61	1.35
WONDERLAND TS	39	0.61	0	0.00	0	0.00	0	0.00	0	0.00	0	0.00	39	0.61
WOODSTOCK TS	36	2.90	0	0.00	0	0.00	0	0.00	0	0.00	1	0.01	37	2.91

Notes on Data

- The FTM DER list consists of both Hydro One owned and non-Hydro One owned DERs.
- Only resources directly connected to Hydro One's network are included. Resources that are indirectly connected to Hydro One's network (i.e., connected to Local Distribution Companies or transmission or distribution assets owned by other parties) are not included.

Section 3.2

Residential Energy Storage Performance Data

Residential Behind the Meter Battery Energy Storage System – Performance Data for 2025

The breakdown of residential behind-the-meter Battery Energy Storage System (BTM BESS) performance data for units connected to Hydro One Networks Inc.'s (Hydro One) distribution system for the period, January to December 2025, is provided below.

BTM BESS Performance Reporting - 2025					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Almonte TS	9.00	0.09	9.07	7.27	80%
Arnprior TS	5.00	0.05	72.40	72.40	100%
Aylmer TS	1.00	0.01	7.33	7.33	100%
Beaverton TS	1.00	0.01	6.83	6.83	100%
Brant TS	2.00	0.02	33.75	33.75	100%
Buchanan TS	2.00	0.02	6.90	6.90	100%
Centralia TS	5.00	0.05	42.18	29.38	70%
Cobden TS	14.00	0.14	910.22	842.78	93%
Constance DS	2.00	0.02	18.53	18.53	100%
Crosby TS	5.00	0.05	346.95	313.62	90%
Des Joachims DS	1.00	0.01	16.98	16.98	100%
Dunnville TS	2.00	0.02	33.68	33.68	100%
Goderich TS	1.00	0.01	19.43	19.43	100%
Havelock TS	6.00	0.06	926.43	708.18	76%
Herridge Lake DS	3.00	0.03	39.05	39.05	100%
Hinchinbrooke DS	5.00	0.05	242.60	221.28	91%
Ingersoll TS	14.00	0.14	310.98	310.98	100%
Kleinburg TS	1.00	0.01	48.62	42.35	87%

BTM BESS Performance Reporting - 2025					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Larchwood TS	4.00	0.04	4.73	4.73	100%
Lindsay TS	5.00	0.05	1699.5	951.72	56%
Martindale TS	6.00	0.06	230.25	214.17	93%
Mattawa DS	1.00	0.01	116.53	116.52	100%
Meaford TS	2.00	0.02	8.62	8.62	100%
Minden TS	28.00	0.28	3000.47	2385.60	80%
Minden TS	2.00	0.02	6.78	6.78	100%
Murillo DS	3.00	0.03	35.97	34.72	97%
Muskoka TS	28.00	0.28	1413.38	1290.47	91%
Muskoka TS	1.00	0.01	69.55	67.80	97%
Orangeville TS	2.00	0.02	41.05	41.05	100%
Otonabee TS	4.00	0.04	295.98	166.73	56%
Parry Sound TS	1.00	0.01	67.78	67.78	100%
Port Arthur TS	4.00	0.04	7.32	7.32	100%
Rockland East DS	1.00	0.01	3.90	3.90	100%
Seaforth TS	1.00	0.01	11.20	11.20	100%
Shabaqua DS	1.00	0.01	37.72	37.72	100%
Sharbot DS	3.00	0.03	42.52	40.27	95%
Smiths Falls TS	63.00	0.63	1306.40	1207.18	92%
Stewartville TS	1.00	0.01	29.55	29.55	100%
Tillsonburg TS	24.00	0.24	371.17	371.15	100%
Trout Lake TS	72.00	0.72	4974.23	4619.90	93%
Trout Lake TS	1.00	0.01	6.35	6.35	100%

BTM BESS Performance Reporting - 2025					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Wallace TS	47.00	0.47	3499.55	3050.37	87%
Wharncliffe DS	1.00	0.01	18.10	18.10	100%
Whitefish DS	11.00	0.11	250.72	244.82	98%
Wolverton DS	3.00	0.03	9.95	9.95	100%

Reference Table	
Name	**Description**
Station Name	Network connection downstream of the first level connection to Hydro One Transmission circuit
Count	Number of BESS Units connected to Station
Capacity	Total MW Capacity of BESS Units at Station
Total Customer Outage Time	Total annual customer x hours of grid outage time
Total Outage Duration Avoided by BESS	Total annual grid outage time (customer x hours) serviced by BESS to reduce customer outage time
% Outage hrs Mitigated	Total customer x hours of outage backed up by BESS divided by Total Customer Outage Time

This page has been left blank intentionally.

Section 3.3

Grid Scale Energy Storage Performance Data

Grid Scale Front of the Meter Battery Energy Storage System – Performance Data for 2025

The breakdown of Hydro One Networks Inc. (Hydro One) owned grid scale front-of-the-meter Battery Energy Storage Systems (FTM BESS) connected to Hydro One's distribution system as of December 31, 2025, is as follows:

Hydro One FTM BESS Performance Data - 2025						
Station Name	**Year**	**# of Grid Outage Events**	**Total Grid Outage (Hours) = (A)**	**BESS Operation (Hours) = (B)**	**% Outage Hrs Mitigated = (B) / (A)**	**Availability %**
Nakina DS (Aroland BESS)	2025	13	34.0	6.2	18%	90%

REFERENCE TABLE	
Name	**Description**
Station Name	Hydro One Station to which FTM BESS is connected
# of Grid Outage Events	Number of annual grid outages experienced by the BESS
Grid Outage	Total annual grid outage time (hours) experienced by BESS
BESS Operation	Total annual grid outage time (hours) serviced by BESS to minimize customer outage time
% Outage Hrs Mitigated	BESS Operation Time divided by Grid Outage Time
Availability %	% of Hours BESS was available to provide support to a grid outage divided by Total In-Service Minutes for Year

This page has been left blank intentionally.