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BY EMAIL

December 20, 2024

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

Dear Ms. Marconi,

EB-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 have been published on Hydro One's website: Transmission Rate Applications, Distribution Rate Applications.

Sincerely,

Kathleen Burke

Appendix A

Section	Description	Settlement Reference[1]
1.0	Scorecards	
1.1	Fiscal 2023 - Hydro One Networks Distribution OEB Scorecard and Management Discussion and Analysis	Part A.2
1.2	Fiscal 2023 - Hydro One Networks Electricity Transmitter Scorecard and Management Discussion and Analysis	Part A.2
2.0	Capital Performance Reports	
2.1	2023 Transmission Capital Performance Report	Part A.1
2.2	2023 Distribution Capital Performance Report	Part A.1
2.3	2023 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 2023 – Hydro One Networks Distribution OEB Scorecard and Management Discussion and Analysis

Fiscal 2023 – 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 2023 Distribution Scorecard is attached and the 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 87% in 2023, 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 78% in 2023, which was slightly less than the target of 80%. This result was attributable to lower satisfaction with the accuracy of reconnection timing and the length of time it took to restore power.

- **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 or not a customer inquiry has been addressed appropriately. This metric demonstrates whether or not services are being 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 2023, which was slightly less than the target of 86%. This result was attributable to lower satisfaction in the areas of Outage, Account / Billing Inquiry and Field Services Calls.

- **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 68% in 2023, which was slightly better than the target of 66%.

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 was $15,216 in 2023, which exceeded the target of $10,608. This result is due to higher input costs including higher material costs, and a higher volume of more complex and labour-intensive poles being completed.

- **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 Year-end Vegetation Management unit cost was $6,996 in 2023, which exceeded the target of $3,824. This result was attributable to greater amounts of vegetation management work required per kilometer than anticipated and increased labour costs.

- **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.

  No station refurbishment projects were completed in 2023 because of equipment procurement issues, easement delays and reprioritization.

- **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.

  OM&A per customer was $459 in 2023, which exceeded the target of $416. This result reflects higher emergency restoration costs and a higher volume of customer-driven work, higher spending on information technology initiatives, and higher environmental expenditures.

- **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 $5,469 in 2023, which exceeded the target of $4,798. This result reflects higher emergency restoration costs and a higher volume of customer-driven work, higher spending on information technology initiatives, and higher environmental expenditures.

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 2.0 hours in 2023, which exceeded the target of 1.7 hours. This result is due to increased storm days in 2023 (38 storm days compared to the 10-year historical average of 33 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 benefit 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 1.7 hours in 2023, which was better than the target of 1.9 hours.

- **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 8.8 hours in 2023, which exceeded the target of 5.2 hours. This is attributed to equipment and tree-caused interruptions arising in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 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 3.2 outages per rural customer in 2023, which exceeded the target of 2.3 outages per rural customer. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 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 3.5 hours in 2023, which exceeded the target of 2.8 hours. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 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 2023, which exceeded the target of 1.5 outages per urban customer. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 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 1.7 interruptions per large distribution customer account in 2023, which exceeded the target of 1.6 interruptions per large distribution customer account. This is attributed to equipment and tree-caused interruptions in part from worse than usual weather including 38 storm days compared to the 10-year historical average of 33 storm days per year.

Note to Readers of Fiscal 2023 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 the collection of customer satisfaction data, and the data’s scope and uses; expected timing of customer perception studies; the means by which customers interact with Hydro One; system reliability measures and expected outcomes of implementation; 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 the scope, duration, and impacts of infectious diseases, including the COVID-19 pandemic and related developments including government and the company’s response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, 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

Year End Results

Performance Outcomes	Performance Categories	Measures	2018	2019	2020	2021	2022	Actual 2023	JRAP Target 2023
Customer Focus	Customer Satisfaction	Small Business and Residential Satisfaction (%)	76%	86%	87%	89%	87%	87%	87%
		Handling of Unplanned Outages Satisfaction (%)	80%	78%	77%	78%	78%	78%	80%
		Call Centre Customer Satisfaction (%)	93%	90%	86%	86%	86%	84%	86%
		My Account Customer Satisfaction (%)	77%	72%	52%	60%	67%	68%	66%
Operational Effectiveness	Cost Control	Pole Replacement - Gross Cost Per Unit in ($)	$9,799	$12,499	$10,624	$11,158	$13,133	$15,216	$10,608
		Vegetation Management - Gross Defect Correction (OCP) Cost per km ($)	$4,910	$5,609	$5,670	$4,019	$5,070	$6,996	$3,824
		Station Refurbishment - Gross Cost Per MVA ($)	$486,000	$512,000	$315,000	$356,899	$655,244	No projects in service	$425,000
		OM&A dollars per customer ($)	$415	$415	$410	$409	$461	$459	$416
		OM&A dollars per km of line ($)	$4,611	$4,644	$4,622	$4,779	$5,441	$5,469	$4,798
	System Reliability	SAIDI for Equipment Caused Interruptions (hrs)	2.1	2.5	2.3	2.1	2.6	2.0	1.7
		SAIDI for Vegetation Caused Interruptions (hrs)	2.8	2.4	3.1	2.7	2.5	1.7	1.9
		SAIDI - Rural - duration (hrs)	7.8	7.9	8.3	7.5	8.0	8.8	5.2
		SAIFI - Rural - frequency of outages	2.4	2.7	2.8	2.6	2.8	3.2	2.3
		SAIDI - Urban - duration (hrs)	2.6	3.2	2.7	2.8	2.8	3.5	2.8
		SAIFI - Urban - frequency of outages	1.3	1.5	1.3	1.4	1.3	1.6	1.5
		Large Customer Interruption Frequency (LDA's) - Interruptions per LDA	2.1	1.5	1.6	1.3	1.5	1.7	1.6

Section 1.2

Fiscal 2023 – Hydro One Networks Electricity Transmitter Scorecard and Management Discussion and Analysis

Fiscal 2023 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 Hydro 2023 One Transmission Scorecard is attached and the 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.

  The Standard Outliers as a Percent of Total Delivery Points was 10.9% in 2023, which was slightly better than the target of 11.0%.

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

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 88% in 2023, which met the target of 88%.

- **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 72% in 2023, which was less than the target of 85%. The result is attributable to an increase in planned outages on transmission-connected generators.

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 0.6 in 2023, which was better than 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 0.54 in 2023, which was slightly better than the target of 0.56.

- **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 0.46 in 2023, which exceeded the target of 0.43. This result is mainly due to an increase in inclement weather and equipment-caused interruptions when compared to the previous 5-year average.

- **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 25.9 in 2023, which was better than the target of 32.6.

- **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 as a result of the outage of some other equipment.

  The System Unavailability was 0.52% in 2023, which was better than the target of 0.62%.

- **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 6.4 minutes in 2023, which was better than the target of 9.0 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 97% in 2023, which was slightly less than the target of 100%. The result is primarily due to timing shifts of System Access and System Renewal projects, partially offset by an increase in System Service projects.

- **CapEx as % of Budget**

  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 97% in 2023, which was slightly less than the target of 100%. The result is primarily due to timing shifts of System Access and System Renewal projects, partially offset by an increase in System Service projects.

- **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 109 in 2023, which was better than the target of 100.

- **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, shieldwire replacement, tower foundations and steel structure coating.

  The TCAI was 91% in 2023, which was less than the target of 100%. This is attributed to fewer transformer unit installations, steel structures coated, and wood pole replacements being completed due to outage cancellations and material delivery delays, and execution challenges as a result of using composite poles versus wood poles.

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 7.8% in 2023, which was slightly better than the target of 7.9%.

- **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 2.2% in 2023, which exceeded the target of 1.9%. This result is due to higher OM&A driven by increases in corrective maintenance, technology and security expenses.

- **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 $2,210 in 2023, which was better than the target of $2,784.

- **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 $1,916 in 2023, which exceeded the target of $1,628. This result is due to increased costs associated with more remote work than planned.

Connection of Renewable Generation

- **% On-time completion of renewables customer impact assessments**

  For Transmission-connected generators, Hydro One is obligated under the Transmission System Code 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.

  No Customer Impact Assessments were reported in 2023.

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 Met was 100% in 2023, which met the target of 100%.

- **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 was met in 2023.

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 0.21 in 2023.

- **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 1.48 in 2023.

- **Profitability: Regulatory Return on Equity**

  Achieved Regulatory Return on Equity (ROE) measures the OEB-approved ROE that is embedded in the transmitter's base rates. ROE is the rate of return that the utility is allowed to earn through its transmission rates, as approved by the OEB.

  The Profitability: Regulated Return on Equity was 10.80% in 2023.

Note to Readers of Fiscal 2023 Scorecard MD&A

The information provided by Transmission Business 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 service quality metrics, including their purposes and frequency of measurement; the development of the transmission system and the progress of the implementation of the transmission system plan; the timing for System Access and System Renewal projects and other system renewal projects; performance measurements regarding end-of-life right-sizing equipment assessment opportunities; 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 the scope, duration, and impacts of infectious diseases, including the COVID-19 pandemic and related developments including government and the company’s response and mitigation measures, legislative or regulatory developments, government policy and program developments, an unexpected increase in call centre volumes, 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

Year End Results

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Actual 2023	JRAP Target 2023
Customer Focus	Service Quality	Customer Delivery Point (DP) Performance Standard Outliers as % of Total DPs (%)		10.1%	10.9%	11.4%	8.3%	9.3%	10.9%	11.0%
	Customer Satisfaction	Overall Customer Satisfaction (%)		90%	87%	83%	92%	88%	88%	88%
		Satisfaction with Outage Planning Procedures (% Satisfied)		85%	84%	71%	82%	78%	72%	85%
Operational Effectiveness	Safety	Recordable Incidents (# of recordable injuries/illnesses per 200,000 hours worked)		1.1	0.8	0.9	0.7	0.6	0.6	0.9
	System Reliability	T-SAIFI-S (Ave. # Sustained interruptions per Delivery Point)		0.83	0.59	0.50	0.49	0.64	0.54	0.56
		T-SAIFI-M (Ave. # of Momentary interruptions per Delivery Point)		0.50	0.43	0.40	0.42	0.43	0.46	0.43
		T-SAIDI (Ave minutes of interruptions per Deliver Point)		70.0	38.9	61.3	21.0	61.0	25.9	32.6
		System Unavailability (%)		0.71%	0.89%	0.83%	0.67%	0.76%	0.52%	0.62%
		Unsupplied energy (minutes)		19.5	13.3	8.0	7.1	13.3	6.4	9.0
	Asset & Project Management	Transmission System Plan Implementation Progress (%)		99%	101%	101%	99%	101%	97%	100%
		CapEx as % of Budget (%)		97%	99%	104%	112%	114%	97%	100%
		OM&A Program Accomplishment (composite index)		107	88	93	105	96	109	100
		Transmission Capital Accomplishment Index (TCAI) - (%)				101%	99%	80%	91%	100%
	Cost Control	Total OM&A and Capital per Gross Fixed Asset Value (%)		7.7%	7.4%	7.9%	8.3%	7.6%	7.8%	7.9%
		OM&A per Gross Fixed Asset Value (%)		2.3%	1.9%	2.1%	2.0%	2.2%	2.2%	1.9%
		Line Clearing Cost per kilometer ($)		$2,797	$3,817	$3,368	$2,211	$2,140	$2,210	$2,784
		Brush Control Cost per Hectare ($)		$1,539	$1,924	$1,538	$1,807	$2,003	$1,916	$1,628
Public Policy Responsiveness	Connection of Renewable Generation	% on-time completion of renewables customer impact assessments (CIAs)		100%	100%	100%	100%	100%	No CIAs in 2023	100%
	Regional Infrastructure Planning (RIP) & Long-Term Energy Plan (LTEP) Right-Sizing	Regional Infrastructure Planning progress - Deliverables met (%)		100%	100%	100%	95%	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)		0.12	0.20	0.28	0.27	0.23	0.21	N/A
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.53	1.52	1.50	1.40	1.37	1.48	N/A
		Profitability: Regulatory Return on Equity	Deemed	9.00%	N/A	8.52%	8.52%	8.52%	9.36%	N/A
			Approved	11.08%	9.53%	9.29%	9.30%	9.92%	10.80%	N/A

Section 2.1

2023 Transmission Capital Performance Report

TRANSMISSION CAPITAL PERFORMANCE REPORT – 2023

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Program Performance Report provides an overview of Hydro One Networks Inc.'s (Hydro One) performance in 2023 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 (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 "Settlement Implementation Forecast" or the "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 2023 Transmission capital expenditures and ISA by OEB investment category and compares them against the OEB-approved Settlement Proposal. The primary focus of this report is on the Transmission System Access, System Renewal, and System Service categories. The Transmission General Plant category is discussed in the General Plant Capital Performance Report.

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

Table 1 - 2023 Transmission Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2023			In-Service Additions – 2023		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$83.6	$61.1	-$22.5	$75.7	$26.4	-$49.2
System Renewal	$1,103.4	$968.2	-$135.2	$1,093.8	$882.2	-$211.6
System Service	$95.6	$139.0	$43.4	$60.6	$228.8	$168.2
General Plant	$143.7	$146.3	$2.6	$160.1	$152.6	-$7.5
Productivity[4]	-$64.2			-$56.2		
Total	**$1,362.1**	**$1,314.6**	**-$47.5**	**$1,334.1**	**$1,290.1**	**-$44.0**

Overall, Hydro One's transmission capital expenditures for 2023 were 3% below the OEB-approved amount and ISA for 2023 were 3% below the OEB-approved amount. The decrease in Hydro One's transmission capital expenditures and ISAs was largely due to lower spending in the System Renewal and System Access category (i.e., customer driven) as described below. These decreases were partly offset by increases in the System Service category.

Notwithstanding lower expenditures at the envelope level, inflationary pressures - including rising costs of goods, services, and labour - and an increase in severe weather events have had an impact. Accordingly, Hydro One has responded to these circumstances by reprioritizing and re-pacing its capital portfolio where it was possible to do so. The OEB categories and associated variance explanations are outlined below.

System Access: System Access capital expenditures were $22.5M below the OEB-approved amount. This variance was primarily driven by the Metrolinx Barrie Corridor Line Relocation project (T-SA-07) where through joint development work with Metrolinx, it was concluded that the contemplated on-corridor solution would not meet the technical and operational requirements of either Hydro One or Metrolinx. The parties have subsequently started to explore a solution to relocate the transmission lines outside of the Metrolinx rail corridor, on an extended timeline/schedule. System Access ISAs were $49.2M below the

[2] Does not include Hydro One affiliates.
[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.

OEB-approved amount. This variance is primarily driven by the Metrolinx Barrie Corridor Line Relocation project (T-SA-07) for the same reason noted above.

System Renewal: System Renewal capital expenditures were $135.2M below the OEB-approved amount. This variance was primarily driven by investment redirections across OEB categories to accommodate mandatory system growth investments that emerged and required system upgrades. This variance reflects lower than planned investments for line refurbishments and integrated station investments, and in particular D2/3H Transmission Line Refurbishment (T-SR-13) which was reprioritized, Murray TS: T14, (T13) & Component Replacement (T-SR-03) due to changes in the scope of work impacting project timing, Bruce B SS ABCB Replacement (T-SR-02) which was substantially completed in 2022, and Replace Legacy SONET Systems (T-SR-11) which was reprioritized as it required additional planning.

System Renewal ISAs were $211.6M below the OEB-approved amount. This variance is primarily driven by Bruce A 500kV ABCB Replacement (T-SR-02) where the project pacing was refined, Wilson TS: T1 & Component Replacement (T-SR-03) where the late delivery of materials impacted the project schedule, Seaforth TS: T1, T2, T5, T6, PCT & Component Replacement (T-SR-03) which was deferred to reevaluate the project scope, and Replace Legacy SONET Systems (T-SR-11) which was reprioritized.

System Service: System Service expenditures were $43.4M above the OEB-approved amount. This variance was primarily driven by the Barrie Area Transmission Upgrade (T-SS-Other) as the cost and schedule were revised to account for customer-initiated delays, scope update, and cost pressures described above. System Service ISAs were $168.2M above the OEB-approved amount. This variance is primarily driven by Barrie Area Transmission Upgrade (T-SS-Other) as outlined above, and Lennox TS 500kV Shunt Reactors (T-SS-Other) due unexpected site conditions and outage constraints which affected the project schedule.

3.0 PERFORMANCE AT THE PROJECT AND PROGRAM LEVEL

Hydro One takes an integrated approach to 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, be it an 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 AACE class of estimate.[5] Projects are typically released for execution and funded based on a Class 3 estimate as further discussed below. As projects are executed, they are managed to allow Hydro One to be responsive to execution challenges and to update the 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 on 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.

3.1 OVERVIEW

The projects and programs discussed in this report represent 96% of the 2023 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.

Hydro One's project performance in relation to project total budgets for all projects with material (greater than or equal to $3M) actual or planned ISA in 2023 is presented in Figure 1 below. The blue vertical lines in the cost variance chart are placed at -20% and +30% which is the range of expected outcomes that most commonly aligns with an AACE Class 3 estimate, and representative of the typical project definition work completed at the

[5] AACE estimate classification is discussed in EB-2021-0110, TSP Section 2.10.

time of business case approval at Hydro One. This figure shows a relatively tight dispersion of cost performance. This demonstrates Hydro One's overall effectiveness in executing projects within the range anticipated when the project budgets were established. This is particularly true for larger projects (>$30M) that are subject to increased rigour and scrutiny as part of the project delivery process. Use of a Class 3 estimate to establish the appropriate range for completed projects is reasonable as that is the basis on which the projects are generally funded, and it is consistent with industry usage of Class 3 criteria for budget authorization or control estimates.

As can be seen, the majority of projects (89% = 39 of 44) have project total variances that fall within the upper range of AACE Class 3 expected outcomes (+30% of nominal value). Examining the 5 projects that are forecast to exceed their project total budgets by more than 30%, one of the projects has a variance due to work definition issues, which arose as project details were refined, and four projects encountered unforeseen execution issues (i.e. unexpected site conditions, outage issues, material issues, etc.).

Similarly, Figure 2 below shows that the vast majority of projects (98% = 43 of 44) were completed / forecast to complete on plan, within 12 months of baseline. A one-year target range is reasonable given that Hydro One's primary outage availability is during the spring and fall due to system conditions and loading, which often leads to project schedule shifts.

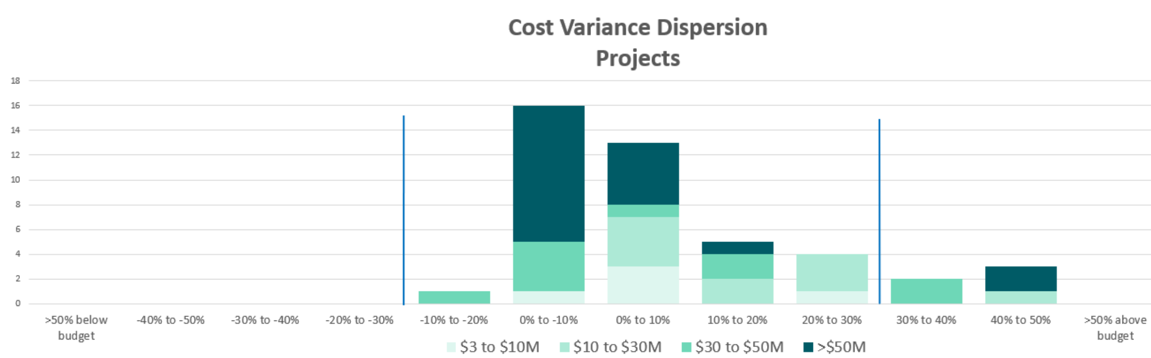

Figure 1: Cost Variance Dispersion for Projects with Planned or Actual ISA in 2023 of $3M or More[6]

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

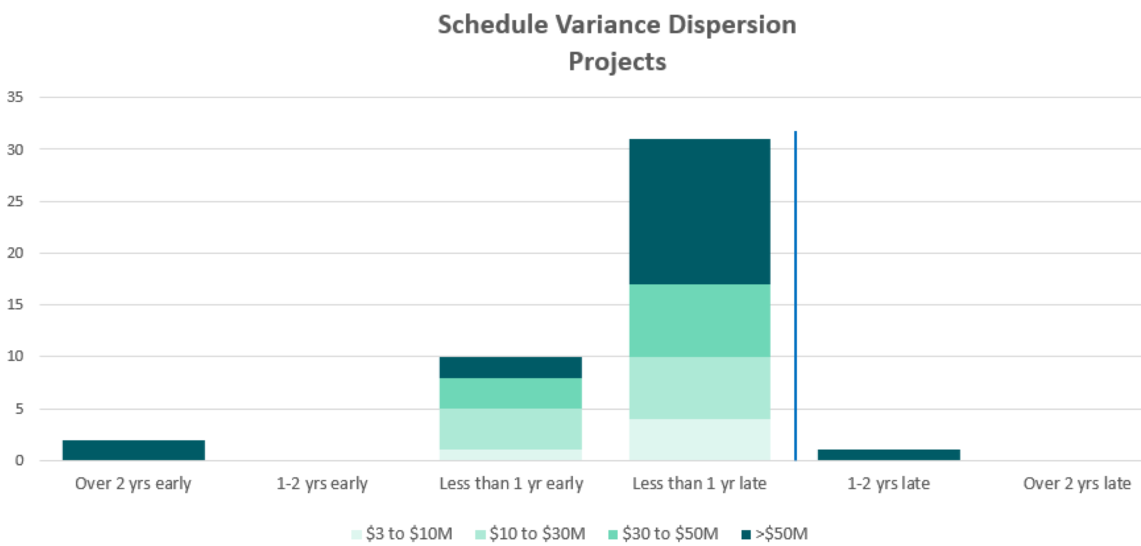

Figure 2: Schedule Variance Dispersion for Projects with Planned or Actual ISA in 2023 of $3M or More[7]

3.2 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2023 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[8]:

- **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** – 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 2023 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

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

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 or 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 materially changing the in-service amount 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, 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.

4.0 PROJECT PERFORMANCE

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

Table 3 - Transmission Project Summary

Project Characteristics			2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[9]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
System Access													
Load Customer Connection													
IAMGOLD - 115 kV Mine Connection, T61S Line Refurbishment[10]	Complete	T-SA-02	17.3	9.9	27.3	22.2	53.7	49.0	-4.7	2023	2023	0	Not a material variance
System Renewal													
Integrated Station Investment													
Arnprior TS - Station Rebuild	Complete	T-SR-03	7.9	8.5	31.4	34.8	31.4	36.2	4.9	2023	2023	0	Work Definition
Beck #1 SS ABCB Replacement	Execution	T-SR-02	9.9	4.0	5.3	3.6	54.2	52.9	-1.3	2026	2026	0	Not a material variance
Beck #2 TS ABCB Replacement	Execution	T-SR-02	10.6	9.4	33.4	11.4	122.2	128.5	6.4	2023	2024	1	Execution Factors
Bridgman TS Load Station Transformer Replacement	Execution	T-SR-03	23.7	21.4	30.0	41.4	69.3	98.1	28.8	2024	2026	2	Execution Factors
Bruce B SS - ABCB Replacement	Complete	T-SR-02	5.2	4.7	10.0	10.1	182.3	181.1	-1.2	2024	2022	-2	Not a material variance
Cecil TS: T1 & Component Replacement	Complete	T-SR-03	4.1	1.8	7.4	0.1	18.5	18.8	0.3	2023	2023	0	Not a material variance
Cherrywood TS 230kV ABCB Replacement	Complete	T-SR-02	8.4	6.1	13.0	6.4	97.9	93.2	-4.7	2023	2023	0	Not a material variance
Cherrywood TS 500kV ABCB Replacement (Phase 3-1)	Execution	T-SR-02	17.2	11.8	18.2	20.8	74.8	71.9	-2.9	2025	2025	0	Not a material variance
Claireville TS: Component Replacement	Execution	T-SR-01	5.5	7.5	2.0	12.9	27.9	33.8	5.9	2025	2025	0	Execution Factors
Fairbank TS: T1, T2, T3, T4, PCT & LV Yard Replacement	Execution	T-SR-03	11.7	13.3	0.1	22.6	70.6	79.3	8.8	2024	2024	0	Execution Factors
Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration	Execution	T-SR-03	18.6	14.9	41.4	30.9	84.2	80.5	-3.7	2023	2024	1	Execution Factors
Hawthorne TS ISCR	Execution	T-SR-03	1.9	1.1	3.7	3.4	44.6	43.2	-1.4	2024	2024	0	Not a material variance

[9] Phases: Planning, Execution, or Complete.
[10] IAMGOLD - 115 kV Mine Connection and T61S Line Refurbishment have been merged in this report as they are being executed as a single project.

Project Characteristics			2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[9]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Keith TS: T11, T12 & Component Replacement	Complete	T-SR-01	9.1	11.1	29.1	19.6	42.0	48.7	6.7	2023	2023	0	Emergent Needs
Kenilworth TS: T1, T3, T4 & Switchyard Refurbishment	Complete	T-SR-03	7.9	5.2	8.5	5.3	49.6	46.7	-2.8	2023	2023	0	Not a material variance
Lambton TS: T7/T8, T5/T6, DESN Replacement	Execution	T-SR-03	35.8	35.3	68.5	53.4	69.9	73.1	3.2	2023	2024	1	Work Definition
Lennox TS: ABCB Component Replacement	Execution	T-SR-02	8.2	13.7	16.5	32.6	143.2	145.8	2.6	2026	2026	0	Not a material variance
Lincoln Heights TS: T1/T2 & Component Replacement	Execution	T-SR-03	8.1	8.0	12.0	11.7	20.2	23.8	3.6	2024	2024	0	Execution Factors
Middleport ABCB Replacement Project	Execution	T-SR-02	26.6	22.2	36.5	36.1	178.1	169.9	-8.2	2025	2025	0	Not a material variance
Milton SS: Component Replacement	Execution	T-SR-01	11.8	13.1	13.6	15.1	20.0	25.7	5.8	2024	2025	1	Execution Factors
Nanticoke TS: T11 & Component Replacement	Complete	T-SR-Other	1.0	1.0	12.2	1.0	18.2	18.4	0.2	2023	2022	-1	Not a material variance
Nanticoke TS: ABCB Replacement	Execution	T-SR-02	16.0	8.7	42.1	38.0	79.0	81.7	2.8	2026	2026	0	Not a material variance
Orangeville TS: Load Station Transformer Replacement	Execution	T-SR-03	4.7	10.5	8.0	9.3	35.6	46.3	10.7	2023	2024	1	Execution Factors
Parry Sound TS: Component Replacement	Complete	T-SR-03	7.2	6.1	12.5	12.3	22.8	23.8	1.0	2023	2023	0	Not a material variance
Pine Portage SS: Component Replacement	Execution	T-SR-01	7.2	4.8	0.0	11.2	38.4	36.8	-1.6	2024	2024	0	Not a material variance
Port Colborne TS: T61, T62 & Switchyard Refurbishment	Complete	T-SR-03	3.1	3.1	3.1	3.1	30.3	31.6	1.3	2022	2022	0	Not a material variance
Rabbit Lake SS: Component Replacement	Execution	T-SR-01	6.7	8.3	8.5	19.0	29.3	35.2	5.9	2024	2024	0	Work Definition
Slater TS T2/T3 & Component Replacement	Execution	T-SR-03	15.5	7.1	23.0	13.3	28.3	32.3	4.0	2024	2024	0	Execution Factors
Spruce Falls TS: Component Replacement	Complete	T-SR-03	2.4	3.9	5.2	6.7	5.5	6.7	1.2	2023	2023	0	Work Definition
Strachan TS T12/T14; A5-A6 M/C & Component Replacement	Complete	T-SR-Other	1.3	1.7	3.9	3.8	3.9	4.0	0.1	2023	2023	0	Not a material variance
Thorold TS: T1, MV Switchyard & Component Replacement	Execution	T-SR-03	6.3	11.9	28.7	32.7	31.8	41.4	9.6	2024	2024	0	Work Definition

Project Characteristics			2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	Project Phase[9]	EB-2021-0110 ISD Number	Forecast	Actual	Forecast	Actual	Forecast	Actual / Latest Forecast	Variance	Forecast	Actual / Latest Forecast	Variance (Years)	Variance Category
Wingham TS: T1, T2, PCT & Component Replacement	Execution	T-SR-03	5.6	13.3	10.0	16.4	23.0	33.5	10.5	2024	2024	0	Execution Factors
Overhead Lines Refurbishment Projects, Component Replacement Programs													
A7L/R1LB/A6P & 57M1 Transmission Line Refurbishment	Complete	T-SR-Other	0.0	3.7	0.0	4.0	85.5	85.2	-0.3	2022	2022	0	Not a material variance
A8/9K Transmission Line Refurbishment	Complete	T-SR-13	14.9	22.6	38.5	38.7	69.5	73.2	3.7	2023	2023	0	Not a material variance
D1A/D3A Transmission Line Refurbishment	Complete	T-SR-Other	2.6	2.2	6.2	6.1	6.2	6.5	0.3	2023	2023	0	Not a material variance
Q3M6 Transmission Line Refurbishment	Execution	T-SR-13	1.1	0.7	3.3	0.0	3.6	3.8	0.2	2024	2024	0	Not a material variance
Protection and Automation													
Telecom Performance - Ring 6/2 (ADSS D6V/E9V)	Complete	T-SR-12	1.3	0.4	4.1	4.8	9.8	9.7	-0.1	2023	2023	0	Not a material variance
System Service													
Inter Area Network Capability													
East-West Tie Connection	Complete	T-SS-Other	7.4	5.1	21.9	21.3	189.0	187.8	-1.2	2024	2022	-2	Not a material variance
Lennox TS 500kV Shunt Reactors	Complete	T-SS-Other	4.8	5.4	33.1	33.8	55.0	54.1	-0.9	2023	2023	0	Not a material variance
M30A/M31A Conductor Upgrade	Complete	T-SS-03	18.8	13.8	19.3	15.5	43.7	38.6	-5.1	2023	2023	0	Not a material variance
St. Lawrence: PS33/PS34 Replacement and Upgrade	Complete	T-SS-02	5.0	4.4	15.6	14.1	33.6	32.7	-0.9	2023	2023	0	Not a material variance
Local Area Supply Adequacy													
Barrie Area Transmission Upgrade	Complete	T-SS-Other	29.7	27.5	84.5	85.7	105.1	100.2	-4.9	2023	2023	0	Not a material variance
Kapuskasing Area Reinforcement - Kapuskasing TS	Complete	T-SS-Other	0.6	0.7	22.9	23.4	22.9	23.7	0.8	2023	2023	0	Not a material variance
Richview x Trafalgar 230kV Conductor Upgrade	Execution	T-SS-04	18.0	24.4	22.0	30.2	59.3	85.4	26.1	2026	2026	0	Execution Factors

1

In terms of the larger project total variances, the **Bridgman TS Load Station Transformer Replacement (T-SR-03)** project is forecasted to exceed its total budget by $28.8M resulting from changes in the contingency tie cable route, estimating assumptions, constructability challenges, and LDC cost escalations. **The Richview x Trafalgar 230kV Conductor Upgrade (SS-04)** is forecasted to exceed its total budget by $26.1M primarily attributable to changes in project definition assumptions, and challenges from new hardware installation. The **Orangeville TS: Load Station Transformer Replacement (SR-03)** is forecasted to exceed its project total budget by $10.7M due to design modifications, scope changes, price increases due to global market conditions and defective materials.

In terms of projects that have had material schedule variances (i.e. delays from 2023 or earlier, to a later year), **the Orangeville TS: Load Station Transformer Replacement (T-SR-03)** project had a delay from 2023 to 2024 due to a delay in material being received and scope additions. The **Gage TS: T3,T4,T5,T6, PCT & Switchyard Reconfiguration (T-SR-03)** project had a delay from 2023 to 2024 due to execution factors from a failed transformer which required project modifications in collaboration with the customer to install a replacement transformer. **The Lambton TS: T7/T8, T5/T6, DESN Replacement (T-SR-03)** project's schedule delay from 2023 to 2024 is mainly attributable to increased time spent on work definition activities. Lastly, the **Beck 2 TS, ABCB Replacement & Yard Upgrade (T-SR-02)** project had a delay from 2023 to 2024 due to outage delays.

5.0 PROGRAM PERFORMANCE

Overall, the aggregate capital expenditure and ISA amounts for System Renewal programs in Table 4 below were above the overall Forecast amounts (+$13.6M and +$26.0M respectively).

Table 4 - Transmission Program Summary

Program Characteristics		2023 Tx Capital Expenditures ($M)			2023 Tx In-Service Additions ($M)			2023 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												
Steel Structure Coating Program	T-SR-05	19.0	12.7	-6.3	19.6	14.2	-5.4	# of Structures	455	297	-158	Reprioritization
Transmission Line Emergency Restoration	T-SR-15	10.6	8.2	-2.4	8.8	8.3	-0.5	# of work orders	115	96	-19	Not a material variance
Wood Pole Structure Replacement	T-SR-04	54.7	72.8	18.1	52.9	67.8	14.9	# of Structures	932	836	-96	Execution Factors
Transmission Line Insulator Replacement	T-SR-08	77.9	68.9	-9.0	72.7	70.0	-2.7	# of Circuit Structures	3,708	3,710	2	Not a material variance
Tx Lines Foundation Assess/Clean/Coat & Life Extension	T-SR-06	11.3	15.9	4.6	11.9	15.8	3.8	# of Structures	739	753	14	Execution Factors
Transmission Line Virtual Asset Inspection	T-SR-Other	3.0	3.0	0.0	5.3	0.0	-5.3	# of Circuit Structures	2,210	-	-2,210	Reprioritization
Transmission Line Shieldwire Replacement	T-SR-07	12.5	15.2	2.7	14.9	16.5	1.6	# of km	293	196	-97	Work Definition
Protection Relay Replacement Program	T-SR-10	9.1	5.1	-4.0	3.7	0.5	-3.3	# of Upgrades	40	1	-39	Reprioritization
Online DGA Monitor Program	T-SR-Other	3.0	3.8	0.7	3.8	3.6	-0.2	# of Installations	13	16	3	Reprioritization
Nuisance Wildlife Control	T-SR-Other	1.0	3.4	2.4	0.7	4.1	3.4	# of Orders	10	9	-1	Execution Factors
Transmission Station Demand, Spares and Targeted Assets	T-SR-09	43.4	50.2	6.8	32.3	52.0	19.7	n/a	n/a	n/a	n/a	Execution Factors

As noted in Section 2 above, overall System Renewal programs expenditures were reduced to offset increases in other non-discretionary categories. Specific programs are discussed as follows:

The **Wood Pole Structure Replacement (T-SR-04)** program had higher expenditures but was slightly under-accomplished due to wood pole shortages which necessitated the use of composite poles. Composite poles are more costly than wood poles and were the main factor in the increased expenditures.

The **Transmission Lines Insulator Replacement (T-SR-08)** program had lower expenditures but Hydro One was able to complete all budgeted units. The lower expenditures were due to the replacement of more 115kV and 230kV insulators on consecutive structures, leading to lower access and setup costs, and the cancellation of higher cost 500kV work due to outage constraints. Outage cancellations and shorter outage durations hampered execution efforts however work was reprioritized to achieve the budgeted units.

The **Steel Structure Coating (T-SR-05)** program had lower expenditures and unit accomplishments due to redirection to the Wood Pole Structure Replacement (T-SR-04) program to offset higher costs related to the use of composite poles. Notwithstanding the lower overall expenditures in this program, Hydro One completed a higher volume of double circuit work which is more costly.

Other programs that experienced material variances were:

- The **Tx Lines Foundation Assess/Clean/Coat & Life Extension (T-SR-06)** program had higher expenditures mainly due to the higher cost on 500kV structures and increased mobilization costs.
- The **Transmission Shieldwire Replacement (T-SR-07)** program had higher expenditures due to additional scope and outage cancellations.
- The **Protection Relay Replacement (T-SR-10)**, **Online DGA Monitor (T-SR-Other), and Transmission Lines Virtual Asset Inspection (T-SR-Other)** programs experienced portfolio reprioritization causing work to be shifted.
- The **Nuisance Wildlife Control (T-SR-Other)** program had higher expenditures due to increased complexity of wildlife barrier installations.

- The **Transmission Station Demand, Spares and Targeted Assets (T-SR-09)** program had increased costs due to an increase in demand replacements.

Section 2.2

2023 Distribution Capital Performance Report

DISTRIBUTION CAPITAL PERFORMANCE REPORT – 2023

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 2023 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 "Settlement Implementation Forecast" or 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 2023 capital Distribution expenditures and ISA by OEB investment category and compares them against the OEB-approved Settlement Proposal. 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 - 2023 Distribution Capital Expenditures and ISA[2]

OEB Category	Capital Expenditures – 2023			In-Service Additions – 2023		
	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)	OEB-Approved ($M)[3]	Actual ($M)	Variance ($M)
System Access	$252.2	$335.9	$83.7	$252.1	$337.3	$85.3
System Renewal (Excl. AMI 2.0)	$282.0	$264.7	-$17.3	$270.6	$250.3	-$20.2
System Renewal (AMI 2.0 Only)	$32.5	$27.9	-$4.6	$32.4	$0.0	-$32.4
System Service	$182.0	$166.9	-$15.1	$218.1	$149.7	-$68.4
General Plant	$172.2	$194.5	$22.3	$136.9	$235.1	$98.2
Total	**$920.8**	**$989.8**	**$69.0**	**$910.0**	**$972.5**	**$62.5**

Overall, Hydro One's distribution capital expenditures for 2023 were 7% above the OEB-approved amount and ISA for 2023 were 7% above the OEB-approved amount. The increase in Hydro One's distribution capital expenditures and ISAs was largely due to a shift in priorities to focus on connecting new homes and businesses. Additionally, inflationary pressures - including rising costs of goods, services, and labour - and an increase in severe weather events have had an impact. Accordingly, 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 demand driven work within System Renewal category (e.g., trouble calls and storm damage), Hydro One made reductions in System Renewal (i.e. pole replacement, sustainment programs) and System Service (i.e., system upgrade) categories. The OEB categories and associated variance explanations are outlined below.

System Access: System Access capital expenditures and ISAs were higher than the OEB-approved amount by $83.7M and $85.3M respectively. These variances were primarily driven by a higher volume of New Load Connections and Service Upgrades (D-SA-02), including more complex large connection projects. The increase in this demand driven investment category also impacted costs associated with design and estimation

[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)

due to increased project complexity and varying scope compared to historical requests. In addition, there were higher than planned line relocations and third-party attachment requests which contributed to higher spend. Higher costs in the above investments were partly offset by lower expenditures in metering infrastructure due to lower volume.

System Renewal: Capital expenditures and ISAs were lower than the OEB-approved amount by $21.9M and $52.6M respectively. These variances were primarily driven by investment reprioritization to accommodate mandatory System Access investments that emerged. The reduced spend in some programs in this category were partly offset by higher expenditures in the Distribution Lines Storm Damage & Trouble Call Response (D-SR-05) programs due to higher volume, and higher expenditures in PCB equipment replacement (D-SR-06) and the Distribution Stations demand program (D-SR-01). Hydro One reprioritized System Renewal work within Pole Replacement (D-SR-07), and Submarine Cable Replacement (D-SR-09) to manage within the overall Distribution capital expenditure and ISA envelopes while maintaining a safe and reliable distribution network. Furthermore, the pace of the Advanced Meter Infrastructure (AMI 2.0) implementation (D-SR-12) was adjusted to allow for additional scope refinement and to address integration issues.

System Service: Capital expenditures and ISAs were lower than the OEB-approved amount by $15.1M and $68.4M respectively. Some of the variances were driven by investment reprioritization to accommodate mandatory System Access investments that emerged. Deferrals included a delayed start to the Energy Storage Solutions Program (D-SS-04), and several reprioritized Load Growth projects (D-SS-01) given slower than anticipated load growth in some locations.

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 recurs 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 in-service does not occur until energization occurs. 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 97% of the 2023 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.

3.1 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual in-service additions (ISA) in 2023 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]:

- **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 2023 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.

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

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 Distribution 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 redirection 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 21 - Distribution Program Summary

			2023 Dx Capital Expenditures ($M)			2023 Dx In-Service Additions ($M)			2023 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	25.1	45.9	20.8	32.3	50.4	18.1	None	N/A	N/A	N/A	Emergent Needs
System Access	D-SA-02	New Load Connections and Upgrades	158.6	257.7	99.1	177.6	256.6	79.0	# of Connections, & Upgrades	21,326	25,078	3,752	Emergent Needs
System Access	D-SA-04	Metering Sustainment	56.2	30.2	-26.1	55.7	28.7	-27.0	# of Meters Replaced	100,041	50,022	-50,019	Work Definition
System Renewal	D-SR-01	Distribution Stations Demand Capital Program	6.5	15.2	8.7	8.0	13.3	5.4	None	N/A	N/A	N/A	Emergent Needs
System Renewal	D-SR-02	Mobile Unit Substation Program	4.9	3.3	-1.6	3.4	0.1	-3.3	# of MUS	1	0	-1	Execution Factors
System Renewal	D-SR-03	Distribution Station Planned Component Replacement Program	4.7	5.5	0.9	5.7	6.8	1.2	# of Recloser & MUS Structures	163	119	-44	Work Definition
System Renewal	D-SR-05	Distribution Lines Trouble Call and Storm Damage Response Program	111.6	141.4	29.9	117.0	141.1	24.1	None	N/A	N/A	N/A	Emergent Needs
System Renewal	D-SR-06	Distribution Lines PCB Equipment Replacement Program	9.9	14.7	4.7	10.0	14.7	4.7	# of Transformer Replacements	1,529	1,481	-48	Work Definition
System Renewal	D-SR-07	Pole Replacement	58.0	34.7	-23.4	58.8	34.0	-24.8	# of Pole Replacements	5933	2509	-3,424	Reprioritization
System Renewal	D-SR-07	Wood Pole Test and Treat	10.3	13.7	3.4	10.4	13.3	2.9	# of Poles Tested	101,617	114,400	12,783	Emergent Needs
System Renewal	D-SR-07	Wood Pole Structural Refurbishment	6.3	6.1	-0.2	6.4	6.1	-0.2	# of Poles Refurbished	2,785	4,475	1,690	Emergent Needs
System Renewal	D-SR-08	Distribution Lines Minor Component Replacement Program	13.0	10.1	-3.0	7.9	10.1	2.2	# of Components Replaced	3,610	3,444	-166	Reprioritization
System Renewal	D-SR-09	Submarine Cable Replacement Program	12.8	2.7	-10.1	12.1	2.7	-9.4	None	N/A	N/A	N/A	Reprioritization
System Renewal	D-SR-10	Distribution Lines Sustainment Initiatives	8.0	4.5	-3.5	12.1	3.2	-8.9	None	N/A	N/A	N/A	Reprioritization
System Service	D-SS-03	Demand Investments	13.9	24.6	10.7	10.6	23.1	12.5	None	N/A	N/A	N/A	Emergent Needs
System Service	D-SS-04	Energy Storage Solutions	10.1	3.1	-7.0	6.7	2.0	-4.7	# of Battery Systems Installed	200	61	0	Execution Factors
	D-SS-05	Worst Performing Feeders	36.3	36.0	-0.3	37.2	35.4	-1.8	# of Devices	1,013	1,277	264	Work Definition
	D-SS-06	Stray Voltage	4.0	5.6	1.6	4.0	5.5	1.5	None	N/A	N/A	N/A	Emergent Needs

The **Joint Use and Lines Relocations (D-SA-01)** program expenditures were above the Forecast. This was largely due to a higher volume of work, increased complexity in large line relocation projects, and pressures outlined in Section 2.0 above. Hydro One is required to meet contractual obligations to third parties through Joint Use agreements and to maintain compliance with Hydro One’s distributor licence.

The **New Load Connection, Upgrades, Cancellations (D-SA-02)** program expenditures were above the Forecast. This variance was the largest within the System Access category due to higher demand compared to Forecast. This demand was due to an increased volume of connections, including more large connections which are more expensive to design and construct. This program also experienced higher costs due to pressures outlined in Section 2.0 above. There was also an increase in the volume and size of residential subdivision projects although the connections within those subdivisions will be recorded when residential owners connect to the distribution system.

The **Meter Infrastructure Sustainment (D-SA-04)** program expenditures were below the Forecast largely due to a lower volume of meter failures than initially projected.

The **Distribution Stations Demand Capital (D-SR-01)** program expenditures were above the Forecast due to higher than forecast equipment failures and system upgrades. This work is demand-driven requiring Hydro One to respond to emergent needs. Costs in this category will vary depending on the type of failure, which can range from individual component replacements such as failed switches or electronic reclosers, to failed transformer replacements.

The **Mobile Unit Substations (D-SR-02)** program expenditures were below the Forecast. Due to the failure of a new MUS unit during commissioning, the unit was sent back to the supplier resulting in the delivery being delayed to early 2024.

The **Distribution Station Planned Component Replacement (D-SR-03)** program expenditures were above the Forecast due to a higher volume of work and added scope such as fence replacement, yard extension, and grounding required to accommodate an MUS. The Distribution Station Planned Component Replacement program addresses the planned replacement of individual components in distribution stations.

The **Distribution Lines Trouble Call and Storm Damage Response (D-SR-05)** program expenditures were above the Forecast due to a higher volume of storm damage and trouble call related equipment failure and replacement. This program also experienced higher costs due to pressures outlined in Section 2.0 above. This program includes Trouble Call Poles & Equipment Replacement, Storm Damage, Trouble Sub and Underground Cable Replacement, Post Trouble Call, and Damage Claims.

The **Distribution Lines PCB Equipment Replacement Program (D-SR-06)** program expenditures were above the Forecast due to program acceleration and utilization of added external resources to help ensure compliance with environmental provisions.

Replacement costs were higher where equipment replacement was not like-for-like. Some replacements required a detailed design to accommodate new requirements (e.g., it requires replacement of the pole and transformer).

The **Pole Sustainment Program (D-SR-07)** program contains the Pole Replacement, Wood Pole Test and Treat, and Wood Pole Structural Refurbishment programs. Pole Test and Treat expenditures were above the Forecast due to a larger volume of poles tested and treated. Pole Refurbishment expenditures were slightly below the Forecast, but more poles were refurbished at a lower cost due to efficiencies in execution. Despite significant pressure in demand-driven higher priority work that resulted in reprioritization of resources from pole replacement, Hydro One made efforts to complete pole test and treat and pole refurbishment programs to offset the lower accomplishment and sustain reliability.

The **Distribution Lines Minor Component Replacement Program (D-SR-08)** program in-service additions were above the Forecast due to pressures outlined in Section 2.0 above. Work was reprioritized where feasible. Some of the replacements were also more complex and labour-intensive. Since customer driven work remained elevated throughout the year, Hydro One also leveraged external resources to complete work.

The **Submarine Cable Replacement Program (D-SR-09)** program expenditures were below the Forecast. This was largely due to work reprioritization, where funding for this program was redirected to other higher priority demand-driven work.

The **Distribution Lines Sustainment Initiatives (D-SR-10)** program expenditures were below the Forecast. This was largely due to work reprioritization, where funding for this program was redirected to other higher priority system access investments.

The **Demand Investments (D-SS-03)** program expenditures were above the Forecast due to higher than anticipated costs for work to address localized load growth. These investments include minor distribution system modifications that address system needs identified by customer power quality complaints, feeder studies and system impact assessments. This work is often high priority in nature and requires Hydro One to respond promptly.

The **Energy Storage Solutions (D-SS-04)** program expenditures were below the Forecast due to contracting delays and changing work execution requirements. Energy Storage Solutions include both behind-the-meter Residential Storage for Customers Experiencing Long Interruption Duration (CELID) and front-of-the-meter Grid Scale Storage. Grid Scale Battery Energy Storage Systems are complex and require supporting studies and analysis that have extended the RFP timelines.

The **Worst Performing Feeders Program (D-SS-05)** program expenditures were below the Forecast however unit accomplishments were above the Forecast. Higher than Forecast unit accomplishments were the result of work execution enhancements leading to minimized delays, increased efficiency, and reduced cost.

The **Stray Voltage (D-SS-06)** program expenditures were above the Forecast due to the nature of this program and the volume of work that is required to respond to and correct power quality complaints.

5.0 PROJECT PERFORMANCE

The Distribution capital envelope is predominantly program-based, with smaller scale projects. However, some large System Service investments are required to ensure the system can accommodate load growth. Accordingly, 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 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 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 8 projects in Table 3 above are either in Planning, Deferred, Execution, or Completed phase. Variance explanations have been provided for these where required using the criteria outlined in Section 3.1 above.

Table 3 - Distribution Project Summary

			2023 Dx Capital Expenditures ($M)		2023 Dx In-Service Additions ($M)		Project End Total Cost ($M)			In-Service Year			Performance
Project Name	**Project Phase[5]**	**EB-2021-0110 ISD Number**	**Forecast**	**Actual**	**Forecast**	**Actual**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Forecast**	**Actual / Latest Forecast**	**Variance**	**Variance Category**
Vanastra DS Transformers	Execution	D-SR-04	4.2	0.9	4.3	0.0	4.3	5.8	1.5	2023	2024	1	Work Definition
Beckwith DS F3 Feeder Development	Complete	D-SS-01	3.2	3.4	3.7	3.6	3.7	3.6	-0.1	2023	2023	0	Not a material variance
New Old School DS and feeders	Execution	D-SS-01	6.2	5.9	11.2	9.8	11.2	9.8	-1.4	2023	2023	0	Work Definition
Wikwemikong Supply - Station & Line Work	Execution	D-SS-01	4.8	8.2	6.0	0.0	6.0	9.1	3.1	2023	2024	1	Execution factors
South Middle Road TS DESN1 Feeder Development	Execution	D-SS-01	14.9	32.3	43.8	53.1	130.5	140.6	10.1	2025	2025	0	Not a Material Variance
Curve Inn DS New Feeder	Execution	D-SS-01	5.0	3.4	5.6	0.0	5.6	4.6	-1.0	2023	2024	1	Execution factors
Kirkland Lake Voltage Conversion - Stage 2	Execution	D-SS-01	3.1	1.7	3.9	2.1	3.9	3.2	-0.7	2023	2023	0	Not a material variance
AMI 2.0	Execution	D-SR-12	32.5	27.9	6.8	0.0	705.6	810.6	105.0	2029	2029	0	Execution Factors

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

Several factors impacted project costs and schedule:

Variances between Actual Cost and Preliminary Design Estimates: Initially, project total cost estimates are based on preliminary design, scope, and cost assessments. As projects move towards execution and detailed scoping, project estimates may increase or decrease. In some cases, optimization during detailed design and work execution resulted in a reduction in total project costs compared to plan. Two examples of this are the Curve Inn DS Feeder (D-SS-01) project, and New Old School DS (D-SS-01) project. However, in other cases such as Vanastra DS Transformers (D-SR-04) where detailed design resulted in an increase in total project costs.

Resource Balancing: Increased storm activity, and increased demand from system access programs resulted in re-deployment of internal resources to demand programs. For the South Middle Road TS (D-SS-01) project, where delays could have had customer impacts, Hydro One is utilizing external resources to ensure timely completion of the projects.

Project Specific Factors: The Wikwemikong Supply project (D-SS-01) is in a remote location with no road access. Project costs are expected to be higher than the Forecast due to outage restrictions, and transportation and material costs.

AMI 2.0 Project Implementation (D-SR-12): Hydro One is the first rural utility to undertake AMI 1.0 to AMI 2.0 migration in Ontario. As a result, there was limited information available to accurately estimate the level of complexity involved to safeguard customer billing accuracy during the replacement of the existing AMI 1.0 solution. Pre-deployment work consisting of preliminary scoping of system integration, deployment estimates and obtaining initial meter and network hardware estimates was completed in 2021. This was the basis for the total project forecast of $706M included in EB-2021-0110 with the goal to in-service $581M by 2027, and the remaining portion of the project to be completed by 2029. Detailed vendor estimates for meter and network hardware acquisition, meter and network hardware deployment, and systems integration were obtained in 2022. Scope optimization, vendor selection, meter and network hardware testing and initiation of IT implementation was completed in 2023. As the project developed over these years, the scope and total project cost matured and resulted in a revised project estimate of $811M, an increase of $105M compared to the 2021 estimate. Addressing integration issues early and finalizing vendor contracts improved the overall project estimate. The project is still forecast to in-service $581M of work by 2027 and the remaining work by 2029. Hydro One continues to manage the risks pertaining to large scale meter installation and system integration, as well as opportunities to contain project costs.

Section 2.3

2023 General Plant Capital Performance Report

GENERAL PLANT CAPITAL PERFORMANCE REPORT – 2023

1.0 CAPITAL PERFORMANCE REPORT OVERVIEW

1.1 BACKGROUND

This Capital Program Performance Report provides an overview of Hydro One's performance in 2023 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.

This Capital Performance Report is broken down into two main sections: Section 2 presenting Transmission-allocated General Plant capital expenditures and ISA and Section 3 presenting Distribution-allocated General Plant capital expenditures and ISA.

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 "Settlement Implementation Forecast" or 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.

1.3 PERFORMANCE DEFINITIONS

Projects and programs with planned or actual ISA in 2023 greater than or equal to $3M have been summarized in the tables below along with variance explanations. The

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

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 2023 or earlier, to a later year.

The variance 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 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.

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

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 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 2023 capital expenditures and ISA for the Transmission General Plant category and compares them against the OEB-approved Settlement Proposal.

Table 1 - 2023 Transmission Capital Expenditures and ISA[3]

OEB Category	Capital Expenditures – 2023			In-Service Additions – 2023		
	OEB-Approved ($M)[4]	Actual ($M)	Variance ($M)	OEB-Approved ($M)	Actual ($M)	Variance ($M)
General Plant - Tx	$143.7	$146.3	$2.6	$160.1	$152.6	-$7.5

In 2023, Hydro One's Transmission-allocated General Plant capital expenditures were 2% above the OEB-approved amount and ISAs were 5% below the OEB-approved amount. As described below, these variances are mainly driven by work definition changes to Information Solutions projects.

[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)

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 1 - Transmission General Plant Program Summary

			2023 Tx Capital Expenditures ($M)			2023 Tx In-Service Additions ($M)			2023 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	21.0	21.4	0.4	21.0	21.4	0.4	# of vehicles	443	571	128	Execution Factors
	G-GP-02	Helicopters	3.7	3.9	0.2	3.7	3.9	0.2	# of helicopters	1	2	1	Work Definition
Facilities and Real Estate	G-GP-03	Facilities and Accommodation	9.9	9.9	0.0	3.1	3.6	0.5	N/A	N/A	N/A	N/A	No material variance
	G-GP-04	Transmission Facilities	11.1	12.7	1.6	11.2	11.3	0.1	N/A	N/A	N/A	N/A	No material variance
Information Solutions	G-GP-05	Hardware/Software Refresh and Maintenance	13.7	17	3.3	14.7	13.8	-0.9	N/A	N/A	N/A	N/A	No material variance
	G-GP-10	Physical Security Upgrade	11.7	10.3	-1.4	6.7	11.5	4.8	N/A	N/A	N/A	N/A	Work Definition
	G-GP-11	Security Monitoring	6.6	4.1	-2.5	10.6	2.6	-8.0	N/A	N/A	N/A	N/A	Reprioritization
System Operations	G-GP-12	Common Operating Technology Infrastructure	3.4	4.9	1.5	4.7	4.8	0.1	N/A	N/A	N/A	N/A	No material variance
Operating Infrastructure	G-GP-19	Grid Control Network Sustainment	6.0	6.2	0.2	3.7	7.7	3.9	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 **Transport and Work Equipment (G-GP-01)** program had expenditures that were in line with the Forecast. The program's unit variance was due to more light-duty vehicles (and less heavy-duty vehicles) being replaced than planned. More light-duty vehicles were replaced as heavy-duty vehicles experienced volume restrictions imposed by the chassis manufacturer.

The **Helicopters (G-GP-02)** program had expenditures that were in line with the Forecast. As a result of a vendor discount, Hydro One was able to purchase a second helicopter within the same forecast budget.

The **Physical Security Upgrade (G-GP-10)** program had capital expenditures that were below the Forecast and ISAs that were above Forecast. The ISA variance is due to physical security upgrades that were completed across 28 sites (versus 24 planned sites) to comply with the NERC Cybersecurity Standard CIP-014.

The **Security Monitor (G-GP-11)** program had capital expenditures that were below the Forecast due to planned investments being deferred as a result of work reprioritization.

The **Grid Control Network Sustainment (G-GP-19)** program had capital expenditures that were in line with the Forecast and ISAs that were above Forecast. The ISA variance is due to the delay in gateway devices being delivered in 2022 resulting in several station upgrades being carried over to 2023.

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

				2023 Tx Capital Expenditures ($M)		2023 Tx In-Service Additions ($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**
Information Solutions														
HR Pay Transformation Project	Shared	Execution	G-GP-06	4.8	7.9	27.6	29.8	65.2	77.1	11.9	2023	2024	1	Work Definition
PSIT Cyber EOL - NGDC Upgrade	Transmission	Complete	G-GP-09	2.9	0.7	5.5	4.0	7.6	4.0	-3.6	2023	2023	0	Work Definition
PSIT Cyber EOL - IPS IDS Tipping Point	Transmission	Execution	G-GP-09	6.3	3.5	6.8	3.6	10.5	3.6	-6.9	2023	2023	0	Work Definition
System Operations														
NMS Upgrade Project	Transmission	Execution	G-GP-16	8.9	10.2	38.0	20.6	38.0	45.2	7.2	2023	2024	1	Execution Factors
NOMS Upgrade	Shared	Execution	G-GP-Other	3.8	1.2	6.0	0.0	14.1	14.2	0.1	2023	2024	1	Work Definition

[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 **HR Pay Transformation Project (G-GP-06)** had expenditures that were above the Forecast. The project involves the digitization of Hydro One's HR systems, including the company's onboarding, training, time management, and payroll functions. During execution planning, Hydro One determined that certain critical functions initially intended to be outsourced must be performed on-premises, necessitating incremental IT capital expenditures. 2023 capital expenditures on the project included completing the integration of approximately 55 software interfaces across the company, as well as integration with Hydro One's SAP-based payroll solution. Given the scope and criticality of this project, material expenditures for testing and data-quality assurance were required, necessitating incremental expenditures in 2023 and deferred ISAs from 2022 into 2023.

The **PSIT Cyber EOL investments (including NGDC Upgrade and IPS IDS Tipping Point) (G-GP-09)** had expenditures that were below the Forecast. As the project's scope was refined work definition variances arose as budget and scheduling requirements reduced.

The **NMS Upgrade Project (G-GP-16)** had capital expenditures that were above the Forecast and ISAs that were below the Forecast. During project execution, incremental modeling improvements and testing resources were required to address data-related application issues affecting the state estimator. The additional effort resulted in deferred ISAs from 2023 into 2024.

The **NOMS Upgrade (G-GP-Other)** had expenditures that were below the Forecast. The project's planning phase was extended to allow better coordination and bundling of planned interruptions across the transmission and distribution system, and to ultimately improve customer satisfaction by reducing the numbers of interruptions on the Hydro One system. This change resulted in the in-service year being extended into 2024.

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 2023 capital expenditures and ISA for the Transmission General Plant category and compares them against the OEB-approved Settlement Proposal.

Table 4 - 2023 Distribution Capital Expenditures and ISA[8]

OEB Category	Capital Expenditures – 2023			In-Service Additions – 2023		
	OEB-Approved ($M)[9]	Actual ($M)	Variance ($M)	OEB-Approved ($M)	Actual ($M)	Variance ($M)
General Plant - Dx	$172.2	$194.5	$22.3	$136.9	$235.1	$98.2

In 2023, Hydro One's Distribution-allocated General Plant capital expenditures were 13% above the OEB-approved amount and ISAs were 72% above the OEB-approved amount. As described below, these variances are mainly driven by work definition changes to HR Pay Transformation and Design Optimization and Transformation projects.

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:

[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)

Table 5 - Distribution General Plant Program Summary

			2023 Dx Capital Expenditures ($M)			2023 Dx In-Service Additions ($M)			2023 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	41.3	41.9	0.7	41.2	41.9	0.8	# of vehicle	443	571	128	Execution Factor
	G-GP-02	Helicopters	7.2	7.6	0.4	7.2	7.6	0.4	# of helicopter	1	2	1	Reprioritization
Facilities and Real Estate	G-GP-03	Facilities and Accommodation	41.6	40.7	-0.9	16.9	16.4	-0.5	N/A	N/A	N/A	N/A	No material variance
Information Solutions	G-GP-05	Hardware/Software Refresh and Maintenance	21.6	27.2	5.6	23.0	22.8	-0.2	N/A	N/A	N/A	N/A	No material variance
	G-GP-11	Security Monitor	11.7	3.6	-8.2	11.3	1.3	-10.0	N/A	N/A	N/A	N/A	Reprioritization
System Operations	G-GP-12	Common Operating Technology Infrastructure	4.7	6.7	2.0	6.4	6.6	0.2	N/A	N/A	N/A	N/A	No material variance

[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 **Transport and Work Equipment (G-GP-01)** program had expenditures that were in line with the Forecast. Please see the explanation provided in section 2.2.1.

The **Helicopters (G-GP-02)** program had expenditures that were in line with the Forecast**:** Please see the explanation provided in section 2.2.1.

The **Security Monitoring (G-GP-11)** program had expenditures that were below the Forecast due to planned investments being deferred as a result of work reprioritization.

3.2.2 DISTRIBUTION PROJECT PERFORMANCE

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

1 **Table 6 - Distribution General Plant Project Summary**

				2023 Dx Capital Expenditures ($M)		2023 Dx In-Service Additions ($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														
HR Pay Transformation Project	Shared	Execution	G-GP-06	6.6	10.8	37.6	40.7	65.2	77.1	11.9	2023	2024	1	Work Definition
Customer Digital Experience Journey	Distribution	Planning	G-GP-07 & G-GP-Other	3.5	0.2	3.9	0.0	27.8	20.8	-7.0	2023	2025	2	Reprioritization
Ultralow Overnight Price Option	Distribution	Complete	G-GP (New)	0.0	3.9	0.0	3.9	0.0	3.9	3.9	-	2023	-	Emergent Need
Design Optimization and Transformation (DOT) Project	Distribution	Complete	G-GP-08	6.0	19.1	64.7	72.8	64.7	72.7	8.0	2023	2023	0	Work Definition
System Operations														
NOMS Upgrade	Shared	Execution	GP-Other	5.1	1.7	8.1	0.0	14.1	14.2	0.1	2023	2024	1	Reprioritization

[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 **HR Pay Transformation Project (G-GP-06):** Please see the explanation provided in section 2.2.2.

The **Customer Digital Experience Journey (G-GP-07 & G-GP-Other)** project had expenditures that were below the Forecast as it was deferred due to work reprioritization.

The **Ultralow Overnight Price Option (G-GP (New))** is a new project**.** This project was required to implement a new optional ultra-low overnight (ULO) price plan for electricity consumers on the Regulated Price Plan (RPP).

The **Design Optimization and Transformation (DOT) (G-GP-08)** project's cost increased due to scope changes primarily related to integration with the current SAP version necessitated by the deferred in-service date, additional hardware and licenses costs resulting from an increased number of end users, and incremental interest and overhead costs.

The **NOMS Upgrade (G-GP-Other)** had expenditures that were below the Forecast.
Please see the explanation provided in section 2.2.2.

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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 - 2023

The breakdown of behind-the-meter Distributed Energy Resources (BTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by transmission station as of December 31, 2023 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
AGUASABON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
ALLANBURG TS	21.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.18
ALLISTON TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	2.00	18.24	5.00	18.26
ALMONTE TS	38.00	0.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.00	0.43
ARDOCH DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ARMITAGE TS DESN1	15.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	16.00	0.62
ARMITAGE TS DESN2	22.00	0.56	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.49	24.00	1.05
ARNPRIOR TS	40.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	40.00	0.46
AYLMER TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
BARRIE TS	1.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.20
BATTERSEA DS	8.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.09
BEAMSVILLE TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
BEAVERTON TS	30.00	0.36	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.36
BELLE RIVER TS	8.00	0.10	1.00	0.01	0.00	0.00	0.00	0.00	1.00	0.03	10.00	0.13
BELLEVILLE TS	48.00	1.22	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.90	49.00	2.12
BILBERRY CREEK TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
BIRCH TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.98	2.00	3.98
BLOOMSBURG DS	14.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.18
BRACEBRIDGE TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BRANT TS	16.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.13
BRANTFORD TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
BROCKVILLE TS	45.00	0.87	0.00	0.00	0.00	0.00	0.00	0.00	4.00	13.10	49.00	13.97
BROWN HILL TS	54.00	0.46	1.00	0.01	0.00	0.00	0.00	0.00	2.00	0.64	57.00	1.11
BUCHANAN TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	6.00	0.06
BURLEIGH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CALEDONIA TS	17.00	0.20	4.00	0.01	0.00	0.00	0.00	0.00	2.00	4.00	23.00	4.22
CENTRALIA TS	13.00	0.77	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	14.00	0.78
CHAPLEAU DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.80	1.00	1.80
CHESTERVILLE TS	18.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.19
CLARABELLE TS	16.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.26
CLARENCE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CLARKE TS	16.00	0.44	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.44
CLEARWATER BAY DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
COBDEN DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
COBDEN TS	19.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07	26.00	0.20
COCHRANE WEST DS	7.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.30
COMMERCE WAY TS	7.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	8.00	2.71
CONSTANCE DS	5.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	6.00	0.11
CRAIG DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CRAWFORD TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.79	1.00	0.79
CROSBY TS DESN1	11.00	0.20	1.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	13.00	0.21
CROWLAND TS	7.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	1.00	5.63	8.00	5.68
CRYSTAL FALLS TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
CUMBERLAND DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
DES JOACHIMS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
DOBBIN DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
DOBBIN TS	49.00	0.47	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.50	50.00	2.97
DOUGLAS POINT TS	18.00	0.64	1.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.89
DRYDEN TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
DUART TS DESN1	9.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.31
DUNDAS TS	31.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23	34.00	0.50
DUNNVILLE TS	19.00	0.31	1.00	0.02	0.00	0.00	0.00	0.00	2.00	0.02	22.00	0.35
DYMOND TS	5.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.07	7.00	3.13
EDGEWARE TS	41.00	0.87	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.80	42.00	1.67
ELMIRA TS	2.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.05
ENFIELD TS DESN 1	8.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.52	9.00	0.61
ESPANOLA TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
ETON DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
EVERETT TS	14.00	0.12	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.13
FAUQUIER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
FERGUS TS	92.00	1.44	1.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	93.00	1.47
FOREST JURA DS	13.00	0.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.46
FOREST LEA DS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07
FRONTENAC TS	38.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.00	0.52
GALT TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
GODERICH TS	5.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	6.00	0.17
GRAND BEND EAST DS	6.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.10
GREELY DS	23.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.24
HANOVER TS	59.00	0.59	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	59.00	0.59
HARROWSMITH DS	20.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	20.00	0.16
HAVELOCK TS	31.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	1.00	4.00	32.00	4.25

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
HAWTHORNE TS	36.00	0.37	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	36.00	0.37
HEARST TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
HERRIDGE LAKE DS	1.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	4.00	0.08
HIGHBURY TS	12.00	0.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.22
HINCHINBROOKE DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
HOLLAND TS	11.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.33
HOYLE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
INGERSOLL TS	24.00	1.21	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	27.00	1.24
JARVIS TS	16.00	0.48	2.00	0.01	0.00	0.00	0.00	0.00	4.00	0.03	22.00	0.52
KAPUSKASING TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.16	3.00	0.17
KEEWATIN DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
KEITH TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.40	1.00	3.40
KENORA DS	12.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.10
KENT TS DESN1	10.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	10.00	0.10
KENT TS DESN2	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	3.00	0.77
KINGSTON GARDINER TS DESN1	27.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	27.00	0.21
KINGSTON GARDINER TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	16.80	3.00	16.81
KINGSVILLE TS	13.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	14.00	1.17
KIRKLAND LAKE TS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
KLEINBURG TS	43.00	0.68	1.00	0.01	0.00	0.00	0.00	0.00	3.00	4.62	47.00	5.31
LAFOREST ROAD DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LAMBTON TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
LARCHWOOD TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	5.00	0.05
LAUZON TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.95	1.00	0.95
LAUZON TS DESN2	5.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	6.00	1.05

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
LDC OWNED STATION	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
LEAMINGTON TS DESN 1	10.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	1.00	10.00	11.00	10.30
LEAMINGTON TS DESN 2	2.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.82	3.00	1.33
LINDSAY TS	29.00	1.38	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	31.00	1.40
LODGEROOM DS	11.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.15
LONGLAC TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
LONGUEUIL TS	25.00	0.74	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.74
LONGWOOD TS	22.00	0.33	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.33
MALDEN TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	1.00	9.20	6.00	9.25
MANITOULIN TS	24.00	0.73	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	25.00	0.74
MANOTICK DS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
MARATHON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MARGACH DS	12.00	0.09	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.10
MARIONVILLE DS	6.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.14
MARTINDALE TS	15.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03	18.00	0.15
MASSEY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MAZINAW DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
MEAFORD TS	59.00	0.55	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.99	60.00	3.54
MIDHURST TS DESN1	30.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.75	31.00	1.11
MINDEN TS	47.00	0.36	1.00	0.00	0.00	0.00	1.00	0.04	0.00	0.00	49.00	0.41
MONTEITH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MORRISBURG TS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
MURILLO DS	8.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.07
MUSKOKA TS	62.00	0.98	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06	68.00	1.04
NAPANEE TS	26.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	26.00	0.23

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
NAVAN DS	7.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.07
NEBO TS DESN1	27.00	0.34	0.00	0.00	0.00	0.00	0.00	0.00	2.00	5.25	29.00	5.59
NESTOR FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NEWINGTON DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
NORFOLK TS	22.00	0.41	0.00	0.00	0.00	0.00	0.00	0.00	2.00	2.02	24.00	2.43
NORTHBROOK DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
ORANGEVILLE TS DESN1	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
ORANGEVILLE TS DESN2	90.00	1.03	1.00	0.01	0.00	0.00	0.00	0.00	1.00	0.05	92.00	1.09
ORILLIA TS	38.00	0.35	0.00	0.00	0.00	0.00	0.00	0.00	4.00	3.28	42.00	3.63
ORLEANS TS	20.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.00	21.00	1.25
OTONABEE TS DESN1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
OTONABEE TS DESN2	48.00	0.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	0.60
OWEN SOUND TS	161.00	1.60	1.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	162.00	1.60
PALMERSTON TS	37.00	1.17	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.26	39.00	1.44
PARRY SOUND TS	38.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	39.00	0.29
PEMBROKE TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
PETAWAWA DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.05	3.00	3.06
PIC DS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
PICTON TS	73.00	0.72	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	74.00	0.80
PLEASANT TS DESN1	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
PORT ARTHUR TS #1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
PORT HOPE TS DESN1	46.00	1.54	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.00	47.00	4.54
PUSLINCH DS	28.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	28.00	0.26
RAMORE TS	2.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.04
RED LAKE TS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Count**	**Capacity (MW)**	**Number**	**Capacity (MW)**
ROCKLAND DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
ROCKLAND EAST DS	12.00	0.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.18
RUSSELL DS	6.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.05
SAM LAKE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SAPAWE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SCHREIBER WINNIPEG DS	3.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.02
SEAFORTH TS	11.00	0.29	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.29
SHARBOT DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
SIDNEY TS	38.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	38.00	0.31
SIOUX NARROWS DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
SMITHS FALLS TS	68.00	1.05	0.00	0.00	0.00	0.00	0.00	0.00	23.00	1.44	91.00	2.48
SOUTH GLOUCESTER DS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
SOUTH MARCH TS	31.00	0.30	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.30
SOWERBY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
SPANISH DS	2.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.17
ST ISIDORE TS	22.00	1.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	1.67
ST LAWRENCE TS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
ST MARYS TS	7.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.39
STAYNER TS	51.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	4.00	52.00	4.63
STEWARTVILLE TS	18.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.14
STRATFORD TS	16.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01	17.00	0.62
STRATHROY TS	2.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.01
STRIKER DS	4.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.08
TEMAGAMI DS	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
TILBURY WEST DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
TILLSONBURG TS	23.00	0.31	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.86	28.00	1.17
TIMMINS TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.57	1.00	1.57
TROUT LAKE TS	25.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	28.00	0.28	53.00	0.49
VERNER DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
WALLACE TS	23.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.09	32.00	0.23
WALLACEBURG TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
WANSTEAD TS	4.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.07
WARREN DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
WAUBAUSHENE TS	30.00	0.21	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.21
WENDOVER DS	16.00	0.39	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.39
WHARNCLIFFE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
WHITEFISH DS	10.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06	16.00	0.14
WILHAVEN DS	9.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.17
WILSON TS DESN2	28.00	15.96	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	29.00	15.96
WINGHAM TS	19.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.71
WOLVERTON DS	13.00	0.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.24
WONDERLAND TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
WOODSTOCK TS	15.00	1.13	0.00	0.00	1.00	0.01	0.00	0.00	1.00	1.00	17.00	2.14

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 - 2023

The breakdown of front-of-the-meter Distributed Energy Resources (FTM DER) connected to Hydro One Networks Inc.'s (Hydro One) distribution system by station as of December 31, 2023 is as follows:

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
AGIMAK DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
AGUASABON DS	6.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.09
ALLANBURG TS	70.00	1.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	1.36
ALLISTON TS	41.00	1.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	41.00	1.03
ALMONTE TS	112.00	21.79	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	113.00	21.80
ARDOCH DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
ARMITAGE TS DESN1	73.00	7.18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	73.00	7.18
ARMITAGE TS DESN2	93.00	1.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	93.00	1.26
ARNPRIOR TS	119.00	22.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	119.00	22.20
AYLMER TS	50.00	2.47	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	50.00	2.47
BALLINAFAD MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
BARWICK TS	103.00	25.96	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	25.96
BATTERSEA DS	70.00	1.22	0.00	0.00	1.00	0.25	0.00	0.00	4.00	2.00	75.00	3.47
BEAMSVILLE TS	8.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.17
BEARDMORE DS #2	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.00	0.00	0.00	1.00	6.00
BEAVERTON TS	300.00	57.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	300.00	57.58
BELLE RIVER TS	166.00	3.19	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	167.00	13.19
BELLEVILLE TS	205.00	52.66	0.00	0.00	1.00	0.25	0.00	0.00	1.00	0.50	207.00	53.41
BILBERRY CREEK TS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
BLOOMSBURG DS	17.00	13.24	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	13.24

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
BRACEBRIDGE TS	15.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.13
BRANT TS	107.00	9.67	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	9.67
BRANTFORD TS	11.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	1.00	8.10	12.00	8.21
BROCKVILLE TS	219.00	32.42	0.00	0.00	0.00	0.00	0.00	0.00	2.00	1.00	221.00	33.41
BROWN HILL TS	212.00	32.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	212.00	32.85
BUCHANAN TS	14.00	0.34	0.00	0.00	1.00	2.85	0.00	0.00	0.00	0.00	15.00	3.19
BUNTING TS	0.00	0.00	0.00	0.00	0.00	0.00	2.00	4.00	0.00	0.00	2.00	4.00
BURLEIGH DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CALEDONIA TS	31.00	20.92	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	20.92
CALSTOCK DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
CAMPBELL TS DESN2	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CENTRALIA TS	145.00	5.13	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.50	147.00	5.63
CHESTERVILLE TS	100.00	21.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	21.32
CLARABELLE TS	80.00	2.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.00	2.51
CLARENCE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
CLARKE TS	63.00	1.34	0.00	0.00	1.00	0.30	0.00	0.00	3.00	0.75	67.00	2.39
CLEARWATER BAY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
COBDEN DS	37.00	0.36	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	37.00	0.36
COBDEN TS	137.00	4.41	0.00	0.00	1.00	0.50	0.00	0.00	0.00	0.00	138.00	4.90
COCHRANE WEST DS	19.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	19.00	0.19
COMMERCE WAY TS	91.00	2.76	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	92.00	20.76
CONSTANCE DS	97.00	1.43	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	97.00	1.43
CRAIG DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
CRILLY DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
CROSBY TS	5.00	40.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	40.01

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
CROSBY TS DESN1	49.00	21.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	21.86
CROWLAND TS	15.00	10.27	1.00	9.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	19.27
CRYSTAL FALLS TS	43.00	5.61	0.00	0.00	0.00	0.00	3.00	11.50	0.00	0.00	46.00	17.11
CUMBERLAND DS	21.00	0.38	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.38
DEEP RIVER DS	15.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.27
DES JOACHIMS DS	3.00	0.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.26
DOBBIN DS	24.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	24.00	0.32
DOBBIN TS	189.00	14.02	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.10	191.00	24.12
DOUGLAS POINT TS	117.00	2.07	3.00	11.05	0.00	0.00	0.00	0.00	0.00	0.00	120.00	13.12
DRYDEN TS	31.00	10.27	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.38	33.00	10.65
DUART TS DESN1	103.00	10.91	1.00	10.00	0.00	0.00	0.00	0.00	1.00	0.25	105.00	21.16
DUNDAS TS	211.00	4.77	0.00	0.00	0.00	0.00	0.00	0.00	2.00	8.49	213.00	13.26
DUNNVILLE TS	24.00	0.69	2.00	9.90	0.00	0.00	0.00	0.00	1.00	4.11	27.00	14.70
DYMOND TS	59.00	9.89	0.00	0.00	0.00	0.00	1.00	9.50	0.00	0.00	60.00	19.39
EAR FALLS TS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
EDGEWARE TS	107.00	3.73	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	107.00	3.73
ELLIOT LAKE TS	14.00	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.20
ELMIRA TS	27.00	0.52	0.00	0.00	0.00	0.00	0.00	0.00	2.00	3.23	29.00	3.75
ENFIELD TS DESN 1	92.00	1.52	3.00	35.85	0.00	0.00	0.00	0.00	0.00	0.00	95.00	37.37
ESPANOLA TS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
ETON DS	29.00	0.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	0.32
EVERETT TS	108.00	1.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	108.00	1.07
FALLOWFIELD DS	0.00	0.00	0.00	0.00	1.00	5.55	0.00	0.00	0.00	0.00	1.00	5.55
FAUQUIER DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
FERGUS TS	199.00	2.92	3.00	41.20	0.00	0.00	0.00	0.00	1.00	0.14	203.00	44.25

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
FOREST JURA DS	98.00	1.36	2.00	16.50	0.00	0.00	0.00	0.00	0.00	0.00	100.00	17.86
FOREST LEA DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
FORT WILLIAM TS	2.00	15.90	0.00	0.00	1.00	3.20	0.00	0.00	0.00	0.00	3.00	19.10
FRONTENAC TS	130.00	2.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	130.00	2.23
GALT TS	16.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.14
GODERICH TS	79.00	1.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	79.00	1.14
GRAND BEND EAST DS	42.00	1.00	1.00	0.80	1.00	0.50	0.00	0.00	0.00	0.00	44.00	2.30
GREELY DS	67.00	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.57
HANOVER TS	362.00	8.78	1.00	22.17	0.00	0.00	2.00	0.28	3.00	0.75	368.00	31.98
HARROWSMITH DS	139.00	1.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	139.00	1.22
HAVELOCK TS	242.00	11.50	0.00	0.00	0.00	0.00	1.00	18.00	0.00	0.00	243.00	29.50
HAWTHORNE TS	82.00	11.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	82.00	11.72
HEARST TS	5.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.05
HERRIDGE LAKE DS	4.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.04
HIGHBURY TS	35.00	7.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	35.00	7.48
HINCHINBROOKE DS	39.00	0.58	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.58
HOLLAND TS	77.00	2.41	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	77.00	2.41
INGERSOLL TS	132.00	21.63	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.25	133.00	21.88
INNISFIL MS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
IROQUOIS FALLS DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
JARVIS TS	33.00	4.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	4.20
KAPUSKASING TS	64.00	8.58	0.00	0.00	0.00	0.00	4.00	22.00	0.00	0.00	68.00	30.58
KEITH TS DESN1	6.00	20.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	20.04
KENORA DS	15.00	0.14	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	15.00	0.14
KENT TS DESN1	178.00	2.62	3.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	181.00	32.62

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
KENT TS DESN2	125.00	1.22	2.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	127.00	21.22
KINGSTON GARDINER TS DESN1	147.00	42.26	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	148.00	52.26
KINGSTON GARDINER TS DESN2	34.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.36	35.00	0.97
KINGSVILLE TS	197.00	4.21	3.00	25.80	0.00	0.00	0.00	0.00	1.00	12.00	201.00	42.01
KIRKLAND LAKE TS	34.00	8.50	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	8.50
KLEINBURG TS	172.00	3.54	0.00	0.00	0.00	0.00	0.00	0.00	1.00	3.23	173.00	6.77
LAFOREST ROAD DS	1.00	0.01	0.00	0.00	0.00	0.00	1.00	14.00	0.00	0.00	2.00	14.01
LAMBTON TS	42.00	40.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	42.00	40.60
LARCHWOOD TS	34.00	0.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	34.00	0.85
LAUZON TS DESN1	3.00	0.23	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.23
LAUZON TS DESN2	149.00	2.99	2.00	20.00	1.00	0.25	0.00	0.00	0.00	0.00	152.00	23.24
LDC OWNED STATION	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
LEAMINGTON TS DESN 1	166.00	3.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	166.00	3.25
LEAMINGTON TS DESN 2	43.00	1.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	43.00	1.07
LINDSAY TS	233.00	45.51	0.00	0.00	1.00	0.50	1.00	0.50	1.00	0.34	236.00	46.84
LODGEROOM DS	67.00	1.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	67.00	1.08
LONGLAC TS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
LONGUEUIL TS	143.00	51.39	1.00	0.01	3.00	0.46	0.00	0.00	0.00	0.00	147.00	51.86
LONGWOOD TS	158.00	3.31	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	158.00	3.31
MALDEN TS	109.00	12.35	3.00	29.80	0.00	0.00	0.00	0.00	0.00	0.00	112.00	42.15
MANITOULIN TS	101.00	0.92	2.00	5.60	0.00	0.00	0.00	0.00	0.00	0.00	103.00	6.52
MANITOUWADGE DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
MANITOUWADGE TS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
MANOTICK DS	18.00	0.45	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	19.00	0.95

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
MARATHON DS	17.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.12
MARGACH DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
MARIONVILLE DS	64.00	0.59	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.75	66.00	1.34
MARTINDALE TS	48.00	10.90	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	48.00	10.90
MASSEY DS	13.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.13
MATTAWA DS	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
MAZINAW DS	12.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.10
MEAFORD TS	64.00	1.15	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	65.00	19.15
MIDHURST TS DESN1	244.00	37.72	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	244.00	37.72
MINDEN TS	86.00	2.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	86.00	2.25
MODELAND TS	5.00	50.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	10.84	7.00	60.84
MONTEITH DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MORRISBURG TS	115.00	20.67	1.00	30.00	0.00	0.00	0.00	0.00	0.00	0.00	116.00	50.67
MOUNTAIN CHUTE DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
MURILLO DS	100.00	1.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	100.00	1.19
MUSKOKA TS	222.00	29.01	0.00	0.00	0.00	0.00	1.00	5.00	0.00	0.00	223.00	34.01
NAKINA DS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	1.50	1.00	1.50
NAPANEE TS	230.00	59.97	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	230.00	59.97
NAVAN DS	11.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.09
NEBO TS DESN1	90.00	0.98	0.00	0.00	1.00	3.20	0.00	0.00	0.00	0.00	91.00	4.18
NELSON TS DESN1	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NESTOR FALLS DS	13.00	0.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.12
NEWINGTON DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
NIPIGON DS	2.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02
NORFOLK TS	131.00	19.56	2.00	19.90	0.00	0.00	0.00	0.00	0.00	0.00	133.00	39.46

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
NORTH BAY TS	1.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.08
NORTH SHORE DS	17.00	0.16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	17.00	0.16
NORTHBROOK DS	31.00	0.51	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.51
ORANGEVILLE TS DESN1	3.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	3.00	0.03
ORANGEVILLE TS DESN2	361.00	5.25	5.00	44.23	0.00	0.00	0.00	0.00	0.00	0.00	366.00	49.48
ORILLIA TS	183.00	31.77	0.00	0.00	0.00	0.00	1.00	1.65	1.00	1.06	185.00	34.48
ORLEANS TS	70.00	3.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	70.00	3.07
OTONABEE TS DESN1	17.00	2.33	0.00	0.00	1.00	1.60	0.00	0.00	0.00	0.00	18.00	3.93
OTONABEE TS DESN2	235.00	9.12	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	235.00	9.12
OWEN SOUND TS	370.00	10.49	0.00	0.00	1.00	0.10	0.00	0.00	0.00	0.00	371.00	10.59
PALERMO TS	0.00	0.00	0.00	0.00	1.00	2.10	0.00	0.00	0.00	0.00	1.00	2.10
PALMERSTON TS	256.00	4.66	1.00	0.50	0.00	0.00	0.00	0.00	0.00	0.00	257.00	5.16
PARRY SOUND TS	57.00	3.62	0.00	0.00	0.00	0.00	0.00	0.00	1.00	2.00	58.00	5.62
PEMBROKE TS	33.00	0.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	33.00	0.57
PETAWAWA DS	12.00	0.11	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	12.00	0.11
PIC DS	11.00	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	11.00	0.10
PICTON TS	218.00	28.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	218.00	28.64
PLEASANT TS DESN1	23.00	0.28	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	23.00	0.28
PORT ARTHUR TS #1	30.00	0.27	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.27
PORT COLBORNE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
PORT HOPE TS DESN1	237.00	34.84	0.00	0.00	1.00	0.01	0.00	0.00	0.00	0.00	238.00	34.85
PUSLINCH DS	96.00	1.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	96.00	1.55
RAMORE TS	12.00	8.11	0.00	0.00	0.00	0.00	1.00	0.52	0.00	0.00	13.00	8.63
RED LAKE TS	5.00	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	5.00	0.04
RED ROCK DS	29.00	1.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	29.00	1.25

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
ROCKLAND DS	6.00	0.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.05
ROCKLAND EAST DS	14.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	14.00	0.13
RUSSELL DS	7.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.00	0.13
SCHREIBER WINNIPEG DS	9.00	0.07	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.07
SEAFORTH TS	102.00	2.59	1.00	15.00	0.00	0.00	0.00	0.00	0.00	0.00	103.00	17.59
SHABAQUA DS	9.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.09
SHARBOT DS	22.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	22.00	0.19
SIDNEY TS	246.00	3.94	0.00	0.00	0.00	0.00	1.00	10.00	0.00	0.00	247.00	13.94
SIOUX NARROWS DS	4.00	0.03	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.00	0.03
SMITHS FALLS TS	257.00	83.26	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	257.00	83.26
SOUTH GLOUCESTER DS	13.00	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	13.00	0.15
SOUTH MARCH TS	66.00	1.26	0.00	0.00	0.00	0.00	0.00	0.00	1.00	6.40	67.00	7.66
SOUTH MIDDLE ROAD TS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	1.00	13.33	7.00	13.39
SOWERBY DS	9.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	9.00	0.08
SPANISH DS	6.00	0.06	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.00	0.06
ST ANDREWS TS	2.00	20.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	2.00	20.00
ST ISIDORE TS	162.00	23.02	0.00	0.00	2.00	4.70	0.00	0.00	5.00	1.22	169.00	28.95
ST LAWRENCE TS	80.00	71.22	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	80.00	71.22
ST MARYS TS	51.00	1.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	51.00	1.17
STAYNER TS	199.00	6.03	2.00	28.45	0.00	0.00	0.00	0.00	0.00	0.00	201.00	34.48
STEWARTVILLE TS	84.00	4.35	0.00	0.00	0.00	0.00	1.00	12.06	0.00	0.00	85.00	16.41
STRATFORD TS	170.00	1.96	0.00	0.00	0.00	0.00	0.00	0.00	3.00	1.10	173.00	3.06
STRATHROY TS	59.00	14.58	1.00	4.10	0.00	0.00	0.00	0.00	0.00	0.00	60.00	18.68
STRIKER DS	60.00	2.53	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	60.00	2.53

	Solar		Wind		Biomass		Hydro		Others (Energy Storage, Natural Gas, CHP, Diesel, etc.)		Total	
Station Name	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Count	Capacity (MW)	Number	Capacity (MW)
TALBOT TS DESN2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
TEMAGAMI DS	1.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.01
THOROLD TS	30.00	0.25	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	30.00	0.25
TILBURY WEST DS	48.00	0.56	1.00	10.00	0.00	0.00	0.00	0.00	0.00	0.00	49.00	10.56
TILLSONBURG TS	170.00	2.01	2.00	19.80	0.00	0.00	0.00	0.00	0.00	0.00	172.00	21.81
TIMMINS TS	4.00	0.04	0.00	0.00	0.00	0.00	2.00	20.50	0.00	0.00	6.00	20.54
TROUT LAKE TS	87.00	2.32	0.00	0.00	0.00	0.00	2.00	10.80	0.00	0.00	89.00	13.12
VERMILION BAY DS	8.00	0.08	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.00	0.08
VERNER DS	31.00	0.63	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	31.00	0.63
WALLACE TS	100.00	0.95	0.00	0.00	0.00	0.00	1.00	0.60	0.00	0.00	101.00	1.55
WALLACEBURG TS	174.00	1.71	1.00	10.00	0.00	0.00	0.00	0.00	1.00	5.16	176.00	16.86
WANSTEAD TS	186.00	3.71	1.00	10.00	1.00	2.40	0.00	0.00	0.00	0.00	188.00	16.11
WARREN DS	16.00	0.71	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.71
WAUBAUSHENE TS	141.00	42.86	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	141.00	42.86
WENDOVER DS	62.00	13.08	0.00	0.00	0.00	0.00	0.00	0.00	1.00	0.50	63.00	13.58
WHARNCLIFFE DS	18.00	0.17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	18.00	0.17
WHITEFISH DS	16.00	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	16.00	0.62
WILHAVEN DS	21.00	0.19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	21.00	0.19
WILSON TS DESN2	143.00	21.91	0.00	0.00	0.00	0.00	1.00	0.01	1.00	19.40	145.00	41.32
WINGHAM TS	130.00	1.93	1.00	18.00	0.00	0.00	0.00	0.00	0.00	0.00	131.00	19.93
WOLVERTON DS	61.00	1.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	61.00	1.32
WONDERLAND TS	39.00	0.61	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	39.00	0.61
WOODSTOCK TS	36.00	2.92	0.00	0.00	0.00	0.00	0.00	0.00	2.00	0.02	38.00	2.94

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 2023

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, 2023, is provided below.

BTM BESS Performance Reporting - 2023					
Station Name	**Count**	**Capacity (MW)**	**Total Customer Outage Time [customer x hr]**	**Total Outage Duration Avoided by BESS [customer x hr]**	**% Outage hrs Mitigated**
Buchanan TS	2	0.02	24.3	24.3	100%
Centralia TS	1	0.01	9.4	9.4	100%
Cobden TS	7	0.07	260.6	251.0	96%
Constance DS	1	0.01	0.0	0.0	100%
Crosby TS	1	0.01	0.1	0.1	100%
Dunnville TS	2	0.02	21.7	21.7	100%
Goderich TS	1	0.01	0.1	0.1	100%
Herridge Lake DS	3	0.03	189.0	93.8	50%
Ingersoll TS	3	0.03	0.0	0.0	100%
Larchwood TS	2	0.02	32.4	32.4	100%
Lindsay TS	2	0.02	12.6	12.6	100%
Martindale TS	2	0.02	88.2	88.2	100%
Muskoka TS	6	0.06	269.1	210.2	78%
Parry Sound TS	1	0.01	27.4	18.1	66%
Smiths Falls TS	20	0.20	822.6	646.6	79%
Tillsonburg TS	3	0.03	20.2	20.2	100%
Trout Lake TS	28	0.28	378.8	374.5	99%
Wallace TS	9	0.09	474.6	399.6	84%
Whitefish DS	6	0.06	189.1	183.6	97%
Total	**100**	**1.00**	**2820.2**	**2386.3**	**85%**

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 outage time experienced by BESS units at a Station
Total Outage Duration Avoided by BESS	Total annual grid outage time (customer x hours) serviced by BESS to minimize customer outage time
% Outage hrs Mitigated	Total customer x hours of outage backed up by BESS divided by Total Customer Outage Time

Section 3.3

Grid Scale Energy Storage Performance Data

Grid Scale Front of the Meter Battery Energy Storage System – Performance Data for 2023

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, 2023 is as follows:

Hydro One FTM BESS Performance Data - 2023						
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)	2023	9	32.4	15.7	48%	92%

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