LIST OF APPENDICES

Scorecard - Lakefront Utilities Inc.

9/22/2025

Performance Outcomes	Performance Categories	Measures		2020	2021	2022	2023	2024	Trend	Target	
										Industry	Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		91.17%	92.89%	94.80%	92.66%	91.30%	↑	90.00%	
		Scheduled Appointments Met On Time		100.00%	93.62%	98.89%	96.30%	94.62%	↓	90.00%	
		Telephone Calls Answered On Time		82.27%	95.62%	90.27%	98.76%	98.23%	↑	65.00%	
	Customer Satisfaction	First Contact Resolution		99.77%	99.46%	99.88%	99.94%	99.96%			
		Billing Accuracy		99.79%	99.95%	99.97%	99.98%	99.93%	↑	98.00%	
		Customer Satisfaction Survey Results		77.70%	77.70%	77.00%	77.00%	81.17%			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		83.00%	82.60%	82.60%	83.90%	83.90%			
		Level of Compliance with Ontario Regulation 22/04 [1]		NC	C	C	C	C	→		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	0	0	→		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	→		0.000
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		4.67	0.99	0.63	2.80	3.22	↓		1.41
		Average Number of Times that Power to a Customer is Interrupted [2]		1.53	0.60	0.36	2.02	1.33	↑		0.62
	Asset Management	Distribution System Plan Implementation Progress		Completed	Completed	81%	81.25%	81.25%			
	Cost Control	Efficiency Assessment		2	1	1	1	1			
		Total Cost per Customer [3]		$500	$518	$545	$650	$673			
		Total Cost per Km of Line [3]		$24,061	$24,743	$26,234	$29,514	$31,102			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time			100.00%	100.00%	100.00%	100.00%	→	90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		0.97	0.95	0.78	0.72	1.05			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.15	1.09	0.96	1.01	1.40			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.78%	8.78%	8.66%	8.66%	8.66%			
			Achieved	5.49%	5.93%	10.87%	4.27%	6.60%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.

Legend:

5-year trend
↑ up ↓ down → flat

Current year
target met target not met

2025 Scorecard Management Discussion and Analysis ("2024 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2018 Scorecard MD&A: **http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf**

Scorecard MD&A - General Overview

In 2024, Lakefront Utilities Inc. (LUI) continued to demonstrate strong performance across the Ontario Energy Board's key scorecard measures, reflecting our commitment to providing safe, reliable, and efficient electricity distribution to our customers. LUI consistently exceeded the OEB's performance targets in several areas, including timely service connections, scheduled appointments, call response times, billing accuracy, and first contact resolution. These results highlight the effectiveness of our operational strategies, investment in mobile workforce deployments, and focus on customer engagement and satisfaction. In addition, LUI maintained high standards of public and workplace safety, advanced its Distribution System Plan commitments, and continued to deliver reliable service while controlling costs relative to industry benchmarks. Collectively, these achievements underscore LUI's ongoing dedication to regulatory compliance, customer service excellence, and continuous improvement.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  In 2024, LUI performed at 91.30% with meeting appointments on time, which exceeds the Board's target of 90%.The electric field staff and management can manage all the orders to ensure timely completion in an efficient way due to mobile deployments implemented throughout the organization.

  LUI works closely with developers to incorporate the connection work required during the various phases of construction to connect on time.

- **Scheduled Appointments Met On Time**

  LUI scheduled 93 appointments in 2024 to complete work requested by customers. Similar to prior years, the utility performed well, meeting all scheduled appointments. LUI's performance of 94.62% exceeds the Ontario Energy Board (OEB) target of 90%.

- **Telephone Calls Answered On Time**

  LUI received 4,906 qualifying incoming calls in 2024. The Distribution System Code (DSC) requires calls to be answered within 30 seconds when a customer calls into the customer care line. The Ontario Energy Board has a target for utilities to achieve at least a 65% answering time within 30 seconds from qualifying incoming calls. LUI exceeded these expectations by performing at 98.23%.

Customer Satisfaction

- **First Contact Resolution**

  The Ontario Energy Board issued a new measure to see how successful utilities are at resolving customer requests from the first point of contact with the utility, starting July 1, 2014. Since this was a new implementation, utilities were given the opportunity to independently strategize how they could measure their first contact resolution.

  LUI measures this performance by logging all calls, letters, and emails received, and tracks them to determine if the inquiry was successfully answered at the first point of contact. A series of logged calls would be created to assist the customer service representative to accurately choose the logged call pertaining to the inquiry received. A specific service order has been created to track any call, letter, or email that were not resolved at the first point of contact.

  LUI performed at 99.96% with logging 2 requests needing secondary attempts to resolve.

- **Billing Accuracy**

  It is a crucial part of our business to ensure accuracy on our customer's bill. LUI performs due diligence by testing the consumption levels in correlation to the amount expensed to its customers. The utility also performs analysis of meter reading data and fixing any errors that may arise, before it is input onto the customer's bill.

In 2024, LUI issued 139,125 bills with 94 being inaccurate and requiring corrections and reissuing. LUI performed at 99.93% which is above OEB's standard of 98%.

- **Customer Satisfaction Survey Results**

LUI completed a survey in 2024 based on question scoring and index methodologies prescribed by the Electricity Distribution Association and a market research company called Innovative. A sample size of over 4% of LUI's customers were interviewed. This survey was conducted in 2024 and LUI achieved a rating of 81.17%. This is consistent with prior years and LUI reviewed the survey results to implement new customer engagement methods.

Safety

- **Public Safety**

Public Safety measures are regulated by the Electrical Safety Authority and consists of three components: Public Awareness of Electrical Safety, Compliance with Ontario Regulation 22/04, and the Serious Electrical Incident Index. Details of these three components are indicated below:

- **Component A – Public Awareness of Electrical Safety**

Component A is a survey that measures the public's awareness of key electrical safety concepts related to electrical distribution equipment found in a utility's territory. The survey provides a benchmark of the levels of awareness identifying areas where education and awareness efforts may be needed. LUI's results were 83.90%, an increase of 1.30% since the last survey completed in 2022 (82.60%).

- **Component B – Compliance with Ontario Regulation 22/04**

Component B consists of utility compliance with Ontario Regulation 22/04 - Electrical Distribution Safety. Ontario Regulation 22/04 establishes the safety requirements for the design, construction, and maintenance of electrical distribution systems, particularly in relation to the approvals and inspections required prior to putting electrical equipment into service. Lakefront Utilities Inc. was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety) for the period of March 1, 2023 to February 28, 2024.

- **Component C – Serious Electrical Incident Index**

  Component C consists of the number of serious electrical incidents and fatalities, which may occur within a utility's service territory. This measure is intended to address the impacts and need for improving public electrical safety on the distribution network. Lakefront Utilities Inc. rated 0.00 for serious electrical incidents per 100 km of line in 2024, similar to their achievements for the prior five years.

System Reliability

- **Average Number of Hours that Power to a Customer is Interrupted**

  The average hours that power is interrupted is a measure of system reliability. LUI is continuously improving the reliability of electricity being delivered to its customers by replacing equipment and performing the necessary maintenance on its distribution infrastructure. In 2024, LUI had an average of 3.22 hours that power was interrupted to its customers.

  LUI continues to view the reliability of electricity service as a high priority for its customers and as such, makes continuous efforts to invest where required. Unplanned outages are continuously communicated through various channels such as Facebook, Twitter, the Lakefront App, Live Chat, by phone, and our website, in real-time. Customers are also informed about live updates from the field such as outage size, location(s), the cause, and dispatching information.

- **Average Number of Times that Power to a Customer is Interrupted**

  The average number of times that power to a customer is interrupted is a measure to determine the system reliability of delivering electricity. The average customer experienced power interruption 1.33 times in the year 2024. This is a decrease from 2023.

Asset Management

- **Distribution System Plan Implementation Progress**

As a filing requirement with the Ontario Energy Board, a Distribution System Plan (DSP) needs to be completed by utilities consisting of several areas such as investment lifecycles, maintenance planning, renewable energy plans, and asset management policies. The DSP outlines LUI's forecasted capital expenditures, over the next five (5) years, required to maintain and expand the electricity system to service its current and future customers.

The key areas of focus in LUI's 5 year DSP include:

- Performance Measurement for Continuous Improvement
- Asset Management and Capital Investment Process
- Overview of Assets Managed
- Asset Lifecycle Optimization Policies and Practices
- Capital Expenditure Plan and Process Overview

LUI was on target with completing its DSP and submitted it with the Cost-of-Service rate application that was filed for rates effective January 1, 2022.

Cost Control

- **Efficiency Assessment**

The Ontario Energy Board acquired expert consultants from the Pacific Economics Group LLC (PEG) to evaluate electric distributors' efficiencies. These efficiencies are based on each utility's actual cost compared to the average levels predicted by a study conducted by PEG. Based on the efficiency levels achieved, each utility is grouped in their ranking with the most efficient being assigned to Group 1 and the least efficient to Group 5.

From 2013 to 2020 Lakefront was assigned to Group 2. With 57 electrical distributors across Ontario, LUI proudly achieved a place in the most efficient group, Group 1, again in latest PEG report issued August 18th, 2025.

- **Total Cost per Customer**

The total cost per customer is the sum of Lakefront's capital and operating costs incurred divided by the total number of customers that the distributor serves. LUI's total cost per customer for 2024 was $673 which increased per customer by $23 in comparison to the prior year. The increase of 3.54%.

- **Total Cost per Km of Line**

The total cost per Km of line is a similar measure as above where it can be used as a comparison to other utilities and its past performance levels in terms of cost efficiencies. The total cost is divided by the kilometers of line that LUI operates to serve its customers. In 2024, LUI's cost per km of line was $31,102. Like above, the increase of 5.38%.

Conservation & Demand Management

- **Net Cumulative Energy Savings**

The Conservation and Demand Management programs are being administered directly by the IESO, through Save On Energy programs.

LUI continues to promote conversation tips through social media, customer engagement activities, and newsletters to our customers. Tools were added to our customer portal such as real-time usage information and an electricity pricing plan calculator to assist customers to choose the best price plan based on their actual historical usage.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

Since 2020, connection impact assessments do not need to be reported to the OEB.

- **New Micro-embedded Generation Facilities Connected On Time**

Micro-embedded generations are supplied from renewable energy sources such as sun, wind, and water at a capacity of less than 10 kW. In 2022, LUI had two micro-embedded generation facilities connected.

Financial Ratios

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

The current ratio is a test to see if a company is capable of paying its short-term debts and financial obligations. A ratio under 1 indicates the company's current liabilities is greater than its current assets possibly causing them the inability to meet their short-term obligations. On the other hand, a greater than 1 ratio shows the company has a good standing with meeting its creditor's demand. Although, it depends from industry to industry an adequate current ratio falls between 1.5 and 3.

In 2024, LUI's current ratio was 1.05. The decrease in the current ratio is primarily the result of an increase in inventory costs due to increased pricing and additional inventory ordered for capital jobs to be completed in 2024.

Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The total debt to equity ratio is a measure of financial leverage used to finance a company's assets. This leverage is evaluated from the proportion between the shareholder's equity and debt. Ideally, the Ontario Energy Board structured the capital mix at a 60/40 (or 1.5) ratio. A ratio of more than 1.5 means the company may be highly leveraged with financing and possibly unable to generate adequate cash flow to pay its debt.

LUI's debt-to-equity ratio is 1.40 in 2022. LUI's debt-to-equity ratio is consistent with prior years with immaterial fluctuations.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  The OEB permits an electricity distributor to earn within +/- 3% of the expected 8.66% return of equity. When a distributor performs outside of this earning threshold, a regulatory audit of the distributor's financials could be initiated by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  LUI achieved a return of equity of 6.6% in 2024, which is within the 5.66% to 11.66% range allowed by the Ontario Energy Board.

Note to Readers of 2024 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. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions and the weather. For these reasons, the information on future performance is intended to be management's best judgement on the reporting date of the performance scorecard and could be markedly different in the future.

Empirical Research in Support of Incentive Rate-Setting: 2024 Benchmarking Update

Report to the Ontario Energy Board

August 2025

Pacific Economics Group Research, LLC

Empirical Research in Support of Incentive Rate-Setting: 2024 Benchmarking Update

Report to the Ontario Energy Board

August 2025

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1. Introduction

In 2013, the Ontario Energy Board (OEB) issued a report titled "Rate Setting Parameters and Benchmarking under the Renewed Regulatory Framework for Ontario's Electricity Distributors"[1] (Board Report) in which it set forth the framework for setting rate adjustment formulas for local distribution companies (LDCs or "distributors"). The Board Report provides the OEB's final determination on its policies and approaches to the distributor rate adjustment parameters and the benchmarking of electricity distributor total cost performance. This 2024 Benchmarking Update determines the 2025 stretch factor assignments for distributors in relation to the 2026 rate year.

According to the Board Report, rates will be indexed by a formula "which is used to adjust the distribution rates to reflect expected growth in the distributors' input prices (the inflation factor) less allowance for appropriate rates of productivity and efficiency gains (the X-factor)."[2] The productivity part of the X-Factor is the same for all LDCs. The efficiency gains part of the X-Factor is called the stretch factor and can vary by company. This stretch factor reflects the potential for incremental productivity gains by a given LDC under incentive regulation (i.e., incentive rate mechanism or IRM) which in turn depends on an individual distributor's level of cost efficiency.

These stretch factor assignments are based on the results of a statistical cost benchmarking study designed to make inferences on individual distributors' cost efficiency. An econometric model is used to predict the level of cost associated with each distributor's own operating conditions. Distributors that achieved an actual cost lower than the cost predicted by the model were assigned lower stretch factors than those that did not. The October 18, 2013 report by Pacific Economics Group (PEG) titled "Productivity and Benchmarking Research in Support of Incentive Rate Setting in Ontario" describes the model used to produce the benchmarking results. The work was subsequently updated to include 2013 data in July of

[1] Issued on November 21, 2013 and corrected on December 4, 2013.

[2] Board Report, page 5.

2014[3] and has been updated each year since. This report presents updated benchmarking results that incorporate 2024 data to update the stretch factors.

Section 2 of this report discusses the methodology used for the 2024 update. Section 3 discusses the data used. Section 4 presents the benchmarking results and updated stretch factors. Section 5 discusses additional resources available to distributors to validate the results contained in this report.

2. Benchmarking Methodology

The model used to determine the cost efficiency of distributors is based on econometrics. Distributor cost in this model is estimated as a function of business conditions faced by each distributor. These business conditions include the number of customers served and the price of inputs such as labour and capital. The parameters of this model establish the relationship between each business condition and distributor cost. These parameters were estimated using Ontario distributor data from 2002-2012.

The model can make a prediction of each distributor's cost given its business conditions by multiplying the company's business condition variables by the model parameters and summing the results[4]. The distributor's actual cost is then compared to that predicted by the model. The percentage difference between actual and predicted cost is the measure of cost performance. Companies with larger negative differences between actual and predicted costs are considered better cost performers and therefore eligible for lower stretch factors. A detailed description of the econometric model including estimation technique and other technical details are contained in sections 6 and A2.1 of the PEG report.

[3] "Empirical work in Support of Incentive Rate Setting: 2013 Benchmarking Update".

[4] The table of parameters published in the PEG report was for the full sample. When making predictions of cost for each company, the econometric program estimated the model without including the subject of benchmarking in the sample. Therefore, there exist 59 different sets of parameters which are very similar to each other. For ease of presentation, the PEG report did not present the parameters specific to each distributor. These company-specific parameters are necessary for the calculations and are contained within the working papers associated with this report. Due to amalgamations after 2013, there are now 53 sets of parameters used.

The econometric model used to obtain the updated stretch factors is identical to the model described in the 2013 PEG report. The OEB intentionally decided not to update the parameters of the econometric model to include future years' data. The goal was to establish a fixed benchmark via the unchanged model parameters which would allow distributors a fair opportunity to demonstrate continuous improvement of cost performance and earn a lower stretch factor. The parameters from the model were combined with each company's data – including 2013-2024 data - to produce 2024 predicted cost. The rationale for this decision is discussed in the Board Report and in a memorandum by PEG.[5]

To apply the 2024 values to the model parameters, the data must be transformed to be consistent with how the data were specified for the estimated econometric model. One such transformation is to express many of the explanatory variables as logarithms prior to the model being estimated. The PEG report describes the details of the estimation process in section A2.1. The spreadsheet model and associated documentation discussed in section 5 contain the calculations leading to the cost benchmarking results.

The purpose of the benchmarking work is to evaluate the total cost incurred by each distributor. Table 1 shows the formulas used to calculate the measure of total cost used in PEG's benchmarking analysis. As described in the PEG benchmarking report, adjustments were undertaken with the purpose of standardizing cost to facilitate more accurate cost comparisons among distributors. These adjustments included the treatment of high voltage and low voltage costs.

The variables used to explain total cost are the same as in the previous PEG report. They include outputs such as customers, kWh deliveries, and capacity. Prices for capital and OM&A along with other business conditions such as customer growth and average length of lines are also included. A complete discussion of the explanatory variables can be found in section 6 of the PEG report and the supporting documents to this report discussed in section 5. The

[5] Available on the OEB website in the file "PEG_Memorandum_OEB on_corrections_20131220.pdf"

explanatory variables are used to explain the level of cost incurred by each LDC. Cost that is not accounted for by the variables is deemed to be an estimate of management performance.

3. Benchmarking Data

The source of the cost and output data used in the calculations is from the distributors as reported in the reporting and record-keeping requirements (RRR) filings. The study assumes that the data as reported by the distributors conforms to accounting policies and procedures described in the Accounting Procedures Handbook for Electricity Distributors that includes the Uniform System of Accounts and other instructions contained within the RRR filing system. It also assumes that the LDCs have taken ownership of the data provided to the OEB and significant revisions are not anticipated.[6]

Data sources apart from the RRR are related to input prices. OEB-approved rates of return were obtained from the published OEB Cost of Capital Parameter Updates[7]. Statistics Canada is the source for other input price data. The input price indexes used were the same as those used in PEG's original study with one exception. Statistics Canada no longer calculates the Electric Utility Construction Price Index (EUCPI). The growth in the GDPIPI (FDD) was used to escalate the EUCPI values used in the calculations.[8]

The update was done in the same manner as the original work with an exception. The OEB has improved the quality of data collected related to capital additions. As a result, improved data are available for 2013-2024. PEG has accordingly relied upon these more recently available capital additions data filed in the RRRs instead of inferring these data from changes in gross plant.

[6] The Ontario Energy Board (OEB) released the Report of the Board on Performance Measurement for Electricity Distributors: A Scorecard Approach (EB-2010-0379) on March 5, 2014. This report states that: '*While the Board will create consistent Scorecard reports for distributors, ownership of the data and Scorecard resides with the distributor.'*

[7] https://www.oeb.ca/regulatory-rules-and-documents/rules-codes-and-requirements/cost-capital-parameter-updates

[8] GDPIPI (FDD) is the Gross Domestic Product Implicit Price Index for Final Domestic Demand.

The calculations have also been adjusted for amalgamations that have taken place since the original study was done. The historical cost performance of the combined entity was calculated from the historical results of the predecessor distributors that were amalgamated or acquired.[9] In each of these cases the companies have consolidated reporting and are benchmarked as single entities under the new company names. There was one amalgamation in 2024; Hydro One Networks acquired Chapleau Public Utilities.

This report also addresses the impact of data revisions by LDCs for informational purposes only. The OEB requires distributors to be accountable for the integrity of their reported data. As part of its procedures to improve data quality, the OEB invited distributors to submit corrections to previously provided data. However, a key determination is that already established and published benchmarking results for prior years would not be modified as a result of revised data. This includes any year that comprised the three-year average used to determine the current year's stretch factor. As stretch factors are used directly to set the distribution rates of distributors, they are not subsequently adjusted in order to avoid retroactive rate setting (i.e., rates are final once set unless approved on an interim basis). Consequently, the three years of data used to derive the three-year average for any year's stretch factors are locked-in such that the underlying data used do not change due to any subsequent data revisions. [10] Just as distributors occasionally revise data, PEG sometimes encounters small issues with previous work that it seeks to correct. There were two such corrections this year and neither resulted in a change to previously assigned stretch factors.[11]

[9] The method used to calculation the hypothetical historical cost performance of the combined entity is to sum the actual costs, sum the costs predicted by the model, and calculate the percentage difference. This method is essentially a cost-weighted average of the historical cost performances of the amalgamated distributors.

[10] The previous results were "locked-in" by pasting the values of previous cost performance into the current calculations worksheet. This means that these values will not be affected by subsequent data revisions. This allows for the calculation of a new three-year average of the new 2023 result consistent with the previously published 2020, 2021 and 2022 results while still allowing the calculation of revised results for previous years, if applicable, to show the impact of any data revision.

[11] The first correction was to use the Ontario average weekly earnings for 2021-2023 where we had mistakenly used the analogous values for Canada instead. The average impact of performance scores was 0.02% on average, meaning for the 2021-2023 period distributors appeared to have 0.02% better cost performance than they actually had. The second correction was that part of the amalgamation of Enova Power Corp. from predecessor distributors was done incorrectly. The impact of this correction was to change the average performance score

To show the impacts of data changes on the stretch factors, revised data have been incorporated into the benchmarking databases and model to allow previous results to be recalculated. The revised 2023, 2022, and 2021 results are presented only for the purposes of showing the impact of the data changes. As discussed above, they were not used to calculate the new 2021-2023 average cost performance used to determine the 2024 stretch factors assignments.

Several tables are included at the end of this report. Table 1 describes the calculation of total cost. Table 2 shows each distributor's growth in total cost from 2023 to 2024. Table 3 (A) presents the 2024 benchmarking results and a comparison to prior years' results. Table 3 (B) summarizes data revision impacts on cost performance although they have no bearing on the derivation of the current stretch factors. Table 4 presents average cost performance and associated stretch factors. Table 5 presents the companies assigned to each cohort according to their updated stretch factors. Changes from the previous years' assignments are shown in bold.

The goal of the benchmarking work is to evaluate levels of distributor cost. Table 2 presents the actual OM&A, Capital, and Total (real) cost for each distributor for 2023 and 2024. As can be seen, industry total cost increased by 5.9% on average from 2023-2024. Total OM&A cost grew by 6.82% and capital cost grew on average by 5.11%. The percentage change in capital and total costs are substantially lower than the percentage change in cost growth in 2023 and 2022. Growth in real OM&A cost was the highest of any year (from 2013-2024), while growth in real Capital and Total cost were the fourth- and third-highest rates, respectively.

from -4.2% to -7.4%. For the purposes of calculating 2022-2024 average performance, only the 2024 calculations reflect these corrections and the previously published values for 2022 and 2023 were used when calculating the average performance scores for assigning 2026 stretch factors.

Growth in Real Cost			
Year	OM&A	Capital	Total
2024	6.82%	5.11%	5.90%
2023	5.31%	19.07%	13.05%
2022	6.67%	11.65%	9.29%
2021	2.28%	1.94%	2.01%
2020	1.30%	-3.12%	-0.92%
2019	1.53%	4.32%	3.10%
2018	2.34%	7.20%	4.69%
2017	2.07%	-2.52%	-0.23%
2016	3.38%	1.79%	2.52%
2015	2.73%	4.53%	3.98%
2014	1.53%	5.06%	3.25%
2013	5.86%	-0.46%	2.33%

The econometric model estimates LDCs' costs as a function of distributor output, input price growth, and other business condition variables which are considered as beyond management control. The model will also produce a prediction of the level of cost consistent with these business conditions, and thus "explain" some of the observed cost level. As described in the PEG benchmarking report, changes in distributor cost not accounted for by these factors are deemed to be due to management performance. The parameter estimates measure the average cost impact of the different business conditions and are presented on Table 16 of the PEG benchmarking report. The discussion below provides some details about the parameters and their associated impacts established for the 2002 to 2012 period.

The first of the cost drivers is output quantity. The model uses three measures of the quantity of distributor output. The first is the number of customers served, the second is kWh delivered, and the third is a proxy for the capacity of the distribution system. The capacity variable is described in the PEG report and is equal to the largest peak load experienced as of the current year of data. For example, the 2012 value for the capacity variable is equal to largest reported system summer or winter kW in all the years 2002-2012. Therefore, for 2013 forward, this capacity variable only increased if the distributor's kW demand in that year exceeded kW demand in every year between 2002 and 2012. Of the three output variables, the model estimates that the number of customers has the largest impact on cost, followed by system capacity. The kWh delivered was the least important of the output variables. For the average company, the number of customers was observed to be a more important cost driver than the other two combined. For each 1% change in number of customers, cost was estimated to change by 0.44%.

The second group of cost drivers were the input prices for capital and OM&A. For the average company, the cost impact of changes in the capital price was found to be almost twice as important as that for OM&A. For every 1% change in capital price, the impact on total cost was about 0.63%. The corresponding impact for changes in the OM&A price was 0.37%. The relevant indexes were updated to include 2024 data. For the OM&A price, the growth in average weekly earnings and that for the GDP implicit price index for final domestic demand ("GDPIPI (FDD)") were calculated. The 2023 growth in the OM&A price index is calculated as 70% times average weekly earnings growth plus 30% times GDPIPI (FDD) growth. The 2023 values for the OM&A price index from the previous report were escalated by the growth that occurred in 2024.

The capital price calculation is based upon an asset price index, an economic depreciation rate, and a rate of return. The asset price index was the Electric Utility Construction Price Index as calculated by Statistics Canada. As this index is no longer available, the previous values are escalated by an alternate index. The index chosen was the GDPIPI (FDD) which is the same index used to represent all non-labour price inflation in the Board-approved inflation measure formula[12]. The depreciation rate is fixed at 4.59% consistent with the previous work. The rate of return is a weighted average of the rates for return on equity, long-term debt, and short-term debt as approved by the OEB. The capital price used to calculate total cost is also used as an explanatory variable. Therefore, any changes in the rate of return or asset price index that affect the cost calculation will also affect the price calculation which will in turn "explain" the observed changes in cost.

[12] The weight given to the non-labour index in the inflation formula includes capital cost.

The last group of cost drivers consists of other business condition variables. The first was the percentage of customers added over the last ten years. The second was the average km of distribution line. For each 1% change in average line length, total cost was estimated to increase by 0.29%. The model also contains a time trend that accounts for changes in cost over time that are not accounted for by the other cost drivers. This variable estimates that cost should rise by 1.7% per year for reasons not identified by other variables in the model. All of these business condition variables were updated to include 2024 data.

4. Benchmarking Results and Updated Stretch Factors

Table 3 (A) presents a summary of the current benchmarking results for each distributor from 2021-2024. The updated average cost performance is based on a three-year rolling average calculated from the 2022-2024 values and is used to assign updated stretch factors to distributors. The last column presents the difference between the updated average cost performance and the previous one (2021-2023).[13] The electricity distributor sector has shown consistent year-over-year cost performance improvements. The average level of cost performance in 2024 for the distributors is 14.8% lower than forecast (or predicted) cost that builds upon cost performance improvement in previous years. Previous years also have shown performance improvements for the currently benchmarked distributors but not as good compared to the recent years.

As discussed above, the OEB requires distributors to be accountable for the integrity of their reported data and sets out reporting procedures to improve data quality. OEB Staff reviewed and approved distributors' data corrections requests to previously filed data when reasonable justification is provided. The revised data were incorporated into the benchmarking databases and the 2021, 2022, and 2023 results were recalculated to demonstrate the impact on the previously published 2021-2023 average cost performance.

[13] Changes in average cost performance are due to not only the addition of 2024 results, but the removal of 2021 results. It is therefore possible to simultaneously have improved 2024 cost performance and deteriorating average performance.

Table 3 (B) shows the impact of LDC data revisions on 2021, 2022, and 2023 cost performance for those companies that had approved changes since the previous update. No revisions would have changed previously determined cohort placement.

Updated stretch factors are assigned based on a three-year average of actual less predicted cost over the 2022-2024 period. As discussed in the Board Report, distributors that averaged 25% or more below predicted cost received the lowest stretch factor of 0%. Those that averaged in excess of 10% and up to 25% below predicted cost received a stretch factor of 0.15%. Those within 10% of predicted cost received a stretch factor of 0.30%. Those distributors that had cost in excess of 10% and up to 25% above predicted cost received a stretch factor of 0.45%. Any distributors that had actual costs in excess of 25% more than predicted were assigned the highest stretch factor of 0.60%.

Table 4 presents a summary of the current and previous years' cost performance results and corresponding stretch factors. The assigned stretch factor for all but one company was not affected by the 2024 update. One company has been assigned a different stretch factor, and it is a lower stretch factor. Table 5 presents the updated stretch factor assignments in the format of Appendix D of the Board report.

5. Validation and Other Supporting Documents

As part of their reporting requirements, distributors are asked to validate the numbers contained in their scorecard. The Spreadsheet Model as updated produces the updated benchmarking results contained in this report. It builds on the previous version by adding additional worksheets related to the 2024 calculations.

The format of the additional worksheets used in the update are similar to those provided earlier and the User's Guide will be applicable to the new worksheets. The guide is intended to serve as a tool for distributors to better understand these calculations and their cost performance. The spreadsheet model and users guide are available in the Total cost benchmarking – updates section of the [Performance Assessment] page on the OEB's website.

Table 1
Calculation of 2024 Total Cost

Variable		Reference	Formula	Source
Total Cost			= OM&A + Capital Cost	Formula
OM&A			= A+B+C+D+E+F+G-I+J	Formula
2024	Operation	A		RRR
2024	Maintenance	B		RRR
2024	Billing and Collection	C		RRR
2024	Community Relations	D		RRR
2024	Administrative and General Expenses	E		RRR
2024	Insurance Expense	F		RRR
2024	Advertising Expenses	G		RRR
Adjustments to OM&A				
2024	HV Adjustment	I		RRR
2024	LV Adjustment	J		Hydro One Networks
Capital				
2023	Asset Price Index	K		Previous Year Calculations
2023	Capital Quantity	M		Previous Year Calculations
2024	Asset Price Index	O	=K x (GDPPI-FDD 2021 / GDPPI-FDD 2020)	Formula, Statistics Canada
2024	Capital Additions	P		RRR
2024	HV Capital Additions	Q		RRR
2024	Quantity of Capital Additions	R	=(P-Q) / O	Formula
	Depreciation Rate	S	Fixed at 4.59% for All Years	PEG Report for 4GIR
2024	Capital Quantity	T	= M - S x M + R	Formula
2024	Rate of Return	U		OEB Decision
2024	Capital Price	V	=U x K + S x O	Formula
2024	Capital Cost	W	= V x T	Formula

Table 2

Total Cost by Distributor: 2023 vs. 2024

	OM&A Cost			Capital Cost			Total Cost		
	2023	2024	Percent Change	2023	2024	Percent Change	2023	2024	Percent Change
Alectra Utilities Corporation	275,740,715	280,029,797	1.54%	667,033,540	704,199,058	5.42%	942,774,255	984,228,855	4.30%
Algoma Power Inc.	13,796,191	14,472,132	4.78%	21,053,071	22,361,909	6.03%	34,849,263	36,834,041	5.54%
Atikokan Hydro Inc.	1,188,653	1,333,261	11.48%	697,539	762,769	8.94%	1,886,192	2,096,030	10.55%
Bluewater Power Distribution Corporation	13,684,765	14,325,713	4.58%	18,631,928	19,648,655	5.31%	32,316,693	33,974,368	5.00%
Burlington Hydro Inc.	23,087,139	23,481,258	1.69%	35,988,491	37,966,834	5.35%	59,075,631	61,448,092	3.94%
Canadian Niagara Power Inc.	10,655,338	11,036,706	3.52%	24,171,235	25,557,064	5.58%	34,826,573	36,593,770	4.95%
Centre Wellington Hydro Ltd.	2,804,726	3,127,272	10.89%	3,037,050	3,249,911	6.77%	5,841,776	6,377,182	8.77%
Cooperative Hydro Embrun Inc.	794,475	901,953	12.69%	655,016	655,574	0.09%	1,449,491	1,557,526	7.19%
Elexicon Energy Inc.	46,787,704	52,948,563	12.37%	93,608,204	96,316,805	2.85%	140,395,908	149,265,369	6.13%
E.L.K. Energy Inc.	4,152,335	4,533,419	8.78%	3,360,301	3,659,062	8.52%	7,512,635	8,192,480	8.66%
Enova Power Corp.	39,292,264	44,511,907	12.47%	89,392,498	91,354,324	2.17%	128,684,762	135,866,231	5.43%
Entegrus Powerlines Inc.	16,182,654	17,448,850	7.53%	28,662,967	30,053,298	4.74%	44,845,621	47,502,148	5.75%
ENWIN Utilities Ltd.	27,447,841	30,147,802	9.38%	47,269,397	48,371,913	2.31%	74,717,237	78,519,715	4.96%
EPCOR Electricity Distribution Ontario Inc.	6,068,316	6,581,740	8.12%	6,982,251	7,451,659	6.51%	13,050,567	14,033,399	7.26%
ERTH Power Corporation	8,178,713	8,609,863	5.14%	11,806,645	12,500,077	5.71%	19,985,358	21,109,940	5.47%
Essex Powerlines Corporation	8,624,718	8,669,504	0.52%	13,749,241	14,479,220	5.17%	22,373,959	23,148,724	3.40%
Festival Hydro Inc.	7,046,504	7,438,918	5.42%	9,934,514	10,692,761	7.36%	16,981,018	18,131,680	6.56%
Fort Frances Power Corporation	1,899,201	1,920,340	1.11%	1,185,896	1,190,857	0.42%	3,085,096	3,111,198	0.84%
GrandBridge Energy Inc.	32,538,677	34,830,865	6.81%	52,734,670	55,551,790	5.20%	85,273,346	90,382,655	5.82%
Greater Sudbury Hydro Inc.	16,102,895	17,035,465	5.63%	22,642,502	23,735,005	4.71%	38,745,397	40,770,471	5.09%
Grimsby Power Incorporated	3,889,144	3,918,347	0.75%	4,881,498	5,048,367	3.36%	8,770,642	8,966,714	2.21%
Halton Hills Hydro Inc.	7,576,862	8,340,798	9.61%	15,347,476	15,767,015	2.70%	22,924,338	24,107,813	5.03%
Hearst Power Distribution Company Limited	1,286,493	1,452,278	12.12%	505,938	518,635	2.48%	1,792,430	1,970,913	9.49%
Hydro 2000 Inc.	679,372	744,507	9.16%	212,074	219,723	3.54%	891,446	964,231	7.85%
Hydro Hawkesbury Inc.	1,453,948	1,409,278	-3.12%	772,099	801,969	3.80%	2,226,047	2,211,247	-0.67%
Hydro One Networks Inc.	684,623,857	643,574,939	-6.18%	1,310,817,211	1,400,872,805	6.64%	1,995,441,068	2,044,447,744	2.43%
Hydro Ottawa Limited	106,888,209	107,226,008	0.32%	233,661,781	245,885,215	5.10%	340,549,990	353,111,223	3.62%

Table 2 (cont'd)
Total Cost by Distributor: 2023 vs. 2024

	OM&A Cost			Capital Cost			Total Cost		
	2023	2024	Percent Change	2023	2024	Percent Change	2023	2024	Percent Change
Innpower Corporation	8,088,934	9,106,744	11.85%	16,974,531	20,283,892	17.81%	25,063,464	29,390,636	15.93%
Kingston Hydro Corporation	8,001,856	8,438,504	5.31%	10,898,408	11,102,441	1.85%	18,900,264	19,540,946	3.33%
Lakefront Utilities Inc.	3,107,067	3,188,053	2.57%	4,094,258	4,462,964	8.62%	7,201,325	7,651,017	6.06%
Lakeland Power Distribution Ltd.	6,085,963	6,757,482	10.47%	6,939,695	7,334,616	5.53%	13,025,657	14,092,098	7.87%
London Hydro Inc.	44,158,081	47,225,902	6.72%	73,140,920	76,465,334	4.44%	117,299,001	123,691,237	5.31%
Milton Hydro Distribution Inc.	11,721,468	12,706,432	8.07%	23,607,598	24,311,775	2.94%	35,329,066	37,018,206	4.67%
Newmarket-Tay Power Distribution Ltd.	14,099,664	15,079,727	6.72%	21,773,796	24,401,486	11.39%	35,873,459	39,481,213	9.58%
Niagara Peninsula Energy Inc.	19,942,692	21,894,508	9.34%	33,710,993	34,559,397	2.49%	53,653,685	56,453,905	5.09%
Niagara-on-the-Lake Hydro Inc.	3,367,064	3,825,385	12.76%	5,720,060	5,969,970	4.28%	9,087,124	9,795,355	7.50%
North Bay Hydro Distribution Limited	8,572,962	9,298,073	8.12%	15,406,223	16,082,882	4.30%	23,979,185	25,380,955	5.68%
Northern Ontario Wires Inc.	3,304,043	3,825,875	14.66%	1,744,750	1,971,480	12.22%	5,048,793	5,797,355	13.83%
Oakville Hydro Electricity Distribution Inc.	19,609,317	21,439,118	8.92%	47,200,783	50,991,770	7.73%	66,810,100	72,430,887	8.08%
Orangeville Hydro Limited	3,687,355	4,142,958	11.65%	4,885,998	5,082,411	3.94%	8,573,353	9,225,368	7.33%
Oshawa PUC Networks Inc.	14,608,277	17,290,034	16.85%	30,361,104	31,091,054	2.38%	44,969,381	48,381,088	7.31%
Ottawa River Power Corporation	4,154,241	4,073,876	-1.95%	3,684,454	3,850,026	4.40%	7,838,695	7,923,902	1.08%
PUC Distribution Inc.	12,628,187	12,775,971	1.16%	20,737,214	21,306,116	2.71%	33,365,402	34,082,087	2.13%
Renfrew Hydro Inc.	1,589,812	1,727,396	8.30%	1,637,346	1,690,174	3.18%	3,227,159	3,417,570	5.73%
Rideau St. Lawrence Distribution Inc.	2,763,847	2,929,824	5.83%	1,675,179	1,731,451	3.30%	4,439,026	4,661,275	4.89%
Sioux Lookout Hydro Inc.	1,564,855	1,617,458	3.31%	1,146,181	1,179,618	2.88%	2,711,036	2,797,076	3.12%
Synergy North Corporation	19,053,314	20,027,876	4.99%	28,434,670	29,486,101	3.63%	47,487,984	49,513,977	4.18%
Tillsonburg Hydro Inc.	2,846,612	3,231,949	12.70%	3,559,869	3,738,650	4.90%	6,406,481	6,970,599	8.44%
Toronto Hydro-Electric System Limited	272,554,835	301,886,323	10.22%	936,283,805	994,297,355	6.01%	1,208,838,641	1,296,183,677	6.98%
Wasaga Distribution Inc.	3,461,500	3,809,359	9.58%	5,464,224	5,849,819	6.82%	8,925,724	9,659,178	7.90%
Welland Hydro-Electric System Corp.	7,111,431	8,058,891	12.51%	7,341,487	7,932,934	7.75%	14,452,918	15,991,825	10.12%
Wellington North Power Inc.	2,320,071	2,125,193	-8.77%	1,947,650	2,002,663	2.79%	4,267,721	4,127,856	-3.33%
Westario Power Inc.	6,548,025	7,401,451	12.25%	11,144,186	11,811,549	5.82%	17,692,210	19,213,000	8.25%
Average	**35,234,400**	**35,923,318**	**6.82%**	**76,194,536**	**80,714,343**	**5.11%**	**111,428,936**	**116,637,661**	**5.90%**
Median	**8,001,856**	**8,438,504**	**8.07%**	**11,806,645**	**12,500,077**	**4.74%**	**19,985,358**	**21,109,940**	**5.68%**

Table 3a
Summary of 2024 Cost Performance Results

	Cost Efficiency Assessment						
	2021	2022	2023	2024	**2021-2023**	**2022-2024**	**Difference from 2021-2023**
Alectra Utilities Corporation	-6.9%	-9.1%	-9.7%	-10.9%	-8.6%	-9.9%	-1.4%
Algoma Power Inc.	63.7%	61.1%	61.7%	61.6%	62.2%	61.5%	-0.7%
Atikokan Hydro Inc.	-0.9%	-1.9%	-6.0%	-1.0%	-2.9%	-3.0%	0.0%
Bluewater Power Distribution Corporation	-7.6%	-8.0%	-10.6%	-10.7%	-8.7%	-9.8%	-1.0%
Burlington Hydro Inc.	-11.7%	-13.5%	-10.0%	-11.3%	-11.7%	-11.6%	0.2%
Canadian Niagara Power Inc.	11.8%	9.7%	13.2%	12.2%	11.6%	11.7%	0.1%
Centre Wellington Hydro Ltd.	-16.7%	-16.6%	-18.9%	-15.8%	-17.4%	-17.1%	0.3%
Cooperative Hydro Embrun Inc.	-62.4%	-72.8%	-68.0%	-69.3%	-67.7%	-70.0%	-2.3%
Elexicon Energy Inc.	-2.9%	-3.6%	-4.1%	-3.3%	-3.6%	-3.7%	-0.1%
E.L.K. Energy Inc.	-49.1%	-32.4%	-37.6%	-33.4%	-39.7%	-34.5%	5.2%
Enova Power Corp.	-8.4%	-1.3%	-3.1%	-9.1%	-4.2%	-4.5%	-0.3%
Entegrus Powerlines Inc.	-28.7%	-26.9%	-27.8%	-28.6%	-27.8%	-27.8%	0.0%
ENWIN Utilities Ltd.	-22.4%	-26.8%	-27.8%	-29.2%	-25.7%	-27.9%	-2.2%
EPCOR Electricity Distribution Ontario Inc.	-16.5%	-16.0%	-19.9%	-17.8%	-17.4%	-17.9%	-0.4%
ERTH Power Corporation	-4.8%	-6.5%	-6.5%	-7.2%	-5.9%	-6.7%	-0.8%
Essex Powerlines Corporation	-31.6%	-31.6%	-31.7%	-35.2%	-31.6%	-32.8%	-1.2%
Festival Hydro Inc.	-3.4%	-2.4%	-2.1%	-1.1%	-2.6%	-1.9%	0.8%
Fort Frances Power Corporation	-12.8%	-11.0%	-11.2%	-15.1%	-11.7%	-12.4%	-0.8%

Table 3a (cont'd)
Summary of 2024 Cost Performance Results

	Cost Efficiency Assessment						
	2021	2022	2023	2024	**2021-2023**	**2022-2024**	**Difference from 2021-2023**
GrandBridge Energy Inc.	-11.6%	-13.9%	-15.3%	-15.4%	-13.6%	-14.9%	-1.3%
Greater Sudbury Hydro Inc.	1.4%	-3.8%	-6.9%	-8.0%	-3.1%	-6.2%	-3.1%
Grimsby Power Incorporated	-38.5%	-38.5%	-39.7%	-43.0%	-38.9%	-40.4%	-1.5%
Halton Hills Hydro Inc.	-35.7%	-37.2%	-36.1%	-36.1%	-36.3%	-36.5%	-0.1%
Hearst Power Distribution Company Limited	-30.5%	-33.8%	-33.5%	-29.9%	-32.6%	-32.4%	0.2%
Hydro 2000 Inc.	-16.8%	-14.8%	-20.5%	-18.0%	-17.4%	-17.8%	-0.4%
Hydro Hawkesbury Inc.	-65.3%	-71.0%	-63.6%	-69.6%	-66.6%	-68.1%	-1.4%
Hydro One Networks Inc.	18.1%	20.3%	21.5%	19.2%	20.0%	20.3%	0.4%
Hydro Ottawa Limited	19.5%	23.1%	24.4%	21.6%	22.4%	23.0%	0.7%
Innpower Corporation	-5.2%	-6.2%	-0.8%	5.3%	-4.1%	-0.6%	3.5%
Kingston Hydro Corporation	-12.8%	-10.9%	-15.0%	-17.9%	-12.9%	-14.6%	-1.7%
Lakefront Utilities Inc.	-27.0%	-31.0%	-24.9%	-26.4%	-27.6%	-27.4%	0.2%
Lakeland Power Distribution Ltd.	-19.6%	-16.8%	-16.1%	-13.8%	-17.5%	-15.6%	1.9%
London Hydro Inc.	-5.7%	-6.5%	-8.2%	-8.0%	-6.8%	-7.5%	-0.8%
Milton Hydro Distribution Inc.	-26.8%	-28.1%	-30.1%	-32.3%	-28.3%	-30.2%	-1.8%
Newmarket-Tay Power Distribution Ltd.	-17.6%	-17.5%	-18.1%	-12.3%	-17.8%	-16.0%	1.8%
Niagara Peninsula Energy Inc.	-7.8%	-10.2%	-12.3%	-13.2%	-10.1%	-11.9%	-1.8%
Niagara-on-the-Lake Hydro Inc.	-13.1%	-16.2%	-15.5%	-13.8%	-14.9%	-15.2%	-0.2%
North Bay Hydro Distribution Limited	-3.6%	-3.5%	-4.9%	-4.2%	-4.0%	-4.2%	-0.2%
Northern Ontario Wires Inc.	-45.7%	-45.1%	-46.4%	-37.5%	-45.7%	-43.0%	2.7%

Table 3a (cont'd)

Summary of 2023 Cost Performance Results

	Cost Efficiency Assessment						
	2021	2022	2023	2024	**2021-2023**	**2022-2024**	**Difference from 2021-2023**
Oakville Hydro Electricity Distribution Inc.	-6.4%	-6.6%	-7.5%	-6.0%	-6.8%	-6.7%	0.2%
Orangeville Hydro Limited	-29.6%	-28.4%	-30.6%	-28.6%	-29.5%	-29.2%	0.3%
Oshawa PUC Networks Inc.	-16.8%	-18.9%	-18.9%	-18.2%	-18.2%	-18.6%	-0.5%
Ottawa River Power Corporation	-28.8%	-25.6%	-26.3%	-31.4%	-26.9%	-27.8%	-0.9%
PUC Distribution Inc.	1.8%	-3.0%	15.0%	12.3%	4.6%	8.1%	3.5%
Renfrew Hydro Inc.	-3.1%	-8.4%	-5.7%	-5.7%	-5.7%	-6.6%	-0.9%
Rideau St. Lawrence Distribution Inc.	-15.4%	-11.3%	-15.8%	-14.4%	-14.2%	-13.8%	0.3%
Sioux Lookout Hydro Inc.	-35.1%	-41.9%	-44.1%	-48.0%	-40.3%	-44.7%	-4.3%
Synergy North Corporation	-0.8%	5.0%	2.1%	1.5%	2.1%	2.9%	0.8%
Tillsonburg Hydro Inc.	-9.8%	-15.1%	-17.8%	-15.8%	-14.3%	-16.3%	-2.0%
Toronto Hydro-Electric System Limited	53.2%	52.8%	52.9%	54.7%	52.9%	53.4%	0.5%
Wasaga Distribution Inc.	-56.7%	-45.8%	-44.4%	-42.9%	-49.0%	-44.4%	4.6%
Welland Hydro-Electric System Corp.	-32.6%	-35.7%	-38.9%	-35.0%	-35.7%	-36.5%	-0.8%
Wellington North Power Inc.	-4.0%	-9.8%	-5.3%	-17.2%	-6.4%	-10.8%	-4.4%
Westario Power Inc.	-10.3%	-6.2%	-14.6%	-11.7%	-10.4%	-10.8%	-0.5%
Average	**-14.2%**	**-14.5%**	**-14.8%**	**-14.8%**	**-14.5%**	**-14.7%**	**-0.2%**
Median	**-12.8%**	**-13.5%**	**-15.3%**	**-14.4%**	**-13.6%**	**-14.6%**	**-0.2%**
Max	**63.7%**	**61.1%**	**61.7%**	**61.6%**	**62.2%**	**61.5%**	**5.2%**
Min	**-65.3%**	**-72.8%**	**-68.0%**	**-69.6%**	**-67.7%**	**-70.0%**	**-4.4%**

Table 3b

Summary of the Impact of Revised Data on Cost Performance Results

Distributors with approved 2021, 2022, and/or 2023 data revisions for the 2024 data update	2021 Cost Performance			2022 Cost Performance			2023 Cost Performance			2021-2023 Average Cost Performance*		
	As Previously Calculated	As Revised	Difference	As Previously Calculated	As Revised	Difference	As Previously Calculated	As Revised	Difference	As Previously Calculated	As Revised	**Difference**
Bluewater Power Distribution	-7.6%	na	na	-8.0%	na	na	-10.6%	-10.4%	-0.22%	-8.7%	-8.7%	**-0.07%**
Burlington Hydro Inc.	-11.7%	-11.6%	-0.14%	-13.5%	-13.7%	0.21%	-10.0%	-10.4%	0.39%	-11.7%	-11.9%	**0.15%**
E.L.K. Energy Inc.	-49.1%	na	na	-32.4%	na	na	-37.6%	-37.6%	0.01%	-39.7%	-39.7%	**0.00%**
Entegrus Powerlines Inc.	-28.7%	na	na	-26.9%	na	na	-27.8%	-27.8%	0.00%	-27.8%	-27.8%	**0.00%**
Greater Sudbury Hydro Inc.	1.4%	-0.4%	1.75%	-3.8%	-4.9%	1.18%	-6.9%	-7.6%	0.73%	-3.1%	-4.3%	**1.22%**
Hydro Ottawa Limited	19.5%	18.0%	1.49%	23.1%	20.3%	2.84%	24.4%	20.4%	4.03%	22.4%	19.6%	**2.79%**
Kingston Hydro Corporation	-12.8%	-14.3%	1.40%	-10.9%	-12.2%	1.28%	-15.0%	-16.2%	1.18%	-12.9%	-14.2%	**1.29%**
Milton Hydro Distribution Inc.	-26.8%	na	na	-28.1%	na	na	-30.1%	-30.1%	0.00%	-28.3%	-28.3%	**0.00%**
Oakville Hydro Electricity	-6.4%	na	na	-6.6%	na	na	-7.5%	-7.5%	0.00%	-6.8%	-6.8%	**0.00%**

* The impact of revisions are not cumulative with revisions from previous updates. Other submitted changes were either not used in the 2021-2023 calculations or resulted in no net change to the amounts being used.

Table 4
Summary of Stretch Factor Assignments

	2021-2023		2022-2024		Change in Stretch Factor
	Benchmarking Performance	Stretch Factor	Benchmarking Performance	Stretch Factor	
Alectra Utilities Corporation	-8.6%	0.30	-9.9%	0.30	NO
Algoma Power Inc.	62.2%	0.60	61.5%	0.60	NO
Atikokan Hydro Inc.	-2.9%	0.30	-3.0%	0.30	NO
Bluewater Power Distribution Corporation	-8.7%	0.30	-9.8%	0.30	NO
Burlington Hydro Inc.	-11.7%	0.15	-11.6%	0.15	NO
Canadian Niagara Power Inc.	11.6%	0.45	11.7%	0.45	NO
Centre Wellington Hydro Ltd.	-17.4%	0.15	-17.1%	0.15	NO
Cooperative Hydro Embrun Inc.	-67.7%	0.00	-70.0%	0.00	NO
Elexicon Energy Inc.	-3.6%	0.30	-3.7%	0.30	NO
E.L.K. Energy Inc.	-39.7%	0.00	-34.5%	0.00	NO
Enova Power Corp.	-4.2%	0.30	-4.5%	0.30	NO
Entegrus Powerlines Inc.	-27.8%	0.00	-27.8%	0.00	NO
ENWIN Utilities Ltd.	-25.7%	0.00	-27.9%	0.00	NO
EPCOR Electricity Distribution Ontario Inc.	-17.4%	0.15	-17.9%	0.15	NO
ERTH Power Corporation	-5.9%	0.30	-6.7%	0.30	NO
Essex Powerlines Corporation	-31.6%	0.00	-32.8%	0.00	NO
Festival Hydro Inc.	-2.6%	0.30	-1.9%	0.30	NO
Fort Frances Power Corporation	-11.7%	0.15	-12.4%	0.15	NO

Table 4 (cont'd)
Summary of Stretch Factor Assignments

	2021-2023		2022-2024		**Change in Stretch Factor**
	Benchmarking Performance	Stretch Factor	Benchmarking Performance	Stretch Factor	
GrandBridge Energy Inc.	-13.6%	0.15	-14.9%	0.15	NO
Greater Sudbury Hydro Inc.	-3.1%	0.30	-6.2%	0.30	NO
Grimsby Power Incorporated	-38.9%	0.00	-40.4%	0.00	NO
Halton Hills Hydro Inc.	-36.3%	0.00	-36.5%	0.00	NO
Hearst Power Distribution Company Limited	-32.6%	0.00	-32.4%	0.00	NO
Hydro 2000 Inc.	-17.4%	0.15	-17.8%	0.15	NO
Hydro Hawkesbury Inc.	-66.6%	0.00	-68.1%	0.00	NO
Hydro One Networks Inc.	20.0%	0.45	20.3%	0.45	NO
Hydro Ottawa Limited	22.4%	0.45	23.0%	0.45	NO
Innpower Corporation	-4.1%	0.30	-0.6%	0.30	NO
Kingston Hydro Corporation	-12.9%	0.15	-14.6%	0.15	NO
Lakefront Utilities Inc.	-27.6%	0.00	-27.4%	0.00	NO
Lakeland Power Distribution Ltd.	-17.5%	0.15	-15.6%	0.15	NO
London Hydro Inc.	-6.8%	0.30	-7.5%	0.30	NO
Milton Hydro Distribution Inc.	-28.3%	0.00	-30.2%	0.00	NO
Newmarket-Tay Power Distribution Ltd.	-17.8%	0.15	-16.0%	0.15	NO
Niagara Peninsula Energy Inc.	-10.1%	0.15	-11.9%	0.15	NO
Niagara-on-the-Lake Hydro Inc.	-14.9%	0.15	-15.2%	0.15	NO
North Bay Hydro Distribution Limited	-4.0%	0.30	-4.2%	0.30	NO
Northern Ontario Wires Inc.	-45.7%	0.00	-43.0%	0.00	NO

Table 4 (cont'd)

Summary of Stretch Factor Assignments

	2021-2023		2022-2024		**Change in Stretch Factor**
	Benchmarking Performance	Stretch Factor	Benchmarking Performance	Stretch Factor	
Oakville Hydro Electricity Distribution Inc.	-6.8%	0.30	-6.7%	0.30	NO
Orangeville Hydro Limited	-29.5%	0.00	-29.2%	0.00	NO
Oshawa PUC Networks Inc.	-18.2%	0.15	-18.6%	0.15	NO
Ottawa River Power Corporation	-26.9%	0.00	-27.8%	0.00	NO
PUC Distribution Inc.	4.6%	0.30	8.1%	0.30	NO
Renfrew Hydro Inc.	-5.7%	0.30	-6.6%	0.30	NO
Rideau St. Lawrence Distribution Inc.	-14.2%	0.15	-13.8%	0.15	NO
Sioux Lookout Hydro Inc.	-40.3%	0.00	-44.7%	0.00	NO
Synergy North Corporation	2.1%	0.30	2.9%	0.30	NO
Tillsonburg Hydro Inc.	-14.3%	0.15	-16.3%	0.15	NO
Toronto Hydro-Electric System Limited	52.9%	0.60	53.4%	0.60	NO
Wasaga Distribution Inc.	-49.0%	0.00	-44.4%	0.00	NO
Welland Hydro-Electric System Corp.	-35.7%	0.00	-36.5%	0.00	NO
Wellington North Power Inc.	**-6.4%**	**0.30**	**-10.8%**	**0.15**	**YES**
Westario Power Inc.	-10.4%	0.15	-10.8%	0.15	NO

Table 5

Stretch Factor Assignments by Group

Group I (17 Distributors)		**Group II** (15 Distributors)		**Group III** (17 Distributors)		**Group IV** (3 Distributors)	**Group V** (2 Distributors)
Stretch Factor = **0%**		Stretch Factor = **0.15%**		Stretch Factor = **0.30%**		Stretch Factor = **0.45%**	Stretch Factor = **0.60%**
Cooperative Hydro Embrun Inc.	Lakefront Utilities Inc.	Burlington Hydro Inc.	Newmarket-Tay Power Distribution Ltd.	Alectra Utilities Corporation	Innpower Corporation	Canadian Niagara Power Inc.	Algoma Power Inc.
E.L.K. Energy Inc.	Milton Hydro Distribution Inc.	Centre Wellington Hydro Ltd.	Niagara-on-the-Lake Hydro Inc.	Atikokan Hydro Inc.	London Hydro Inc.	Hydro One Networks Inc.	Toronto Hydro-Electric System Limited
Entegrus Powerlines Inc.	Northern Ontario Wires Inc.	EPCOR Electricity Distribution Ontario Inc.	Niagara Peninsula Energy Inc.	Bluewater Power Distribution Corporation	North Bay Hydro Distribution Limited	Hydro Ottawa Limited	
ENWIN Utilities Ltd.	Orangeville Hydro Limited	Fort Frances Power Corporation	Oshawa PUC Networks Inc.	Elexicon Energy Inc.	Oakville Hydro Electricity Distribution Inc.		
Essex Powerlines Corporation	Ottawa River Power Corporation	GrandBridge Energy Inc.	Rideau St. Lawrence Distribution Inc.	Enova Power Corp.	PUC Distribution Inc.		
Grimsby Power Incorporated	Sioux Lookout Hydro Inc.	Hydro 2000 Inc.	Tillsonburg Hydro Inc.	ERTH Power Corporation	Renfrew Hydro Inc.		
Halton Hills Hydro Inc.	Wasaga Distribution Inc.	Kingston Hydro Corporation	**Wellington North Power Inc.**	Festival Hydro Inc.	Synergy North Corporation		
Hearst Power Distribution Company Limited	Welland Hydro-Electric System Corp.	Lakeland Power Distribution Ltd.	Westario Power Inc.	Greater Sudbury Hydro Inc.			
Hydro Hawkesbury Inc.							

NEEDS ASSESSMENT REPORT

Peterborough to Kingston Region

Date: December 20, 2024

Needs Assessment Report

Peterborough to Kingston

December 20, 2024

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Prepared by: Peterborough to Kingston Technical Working Group

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Disclaimer

This Needs Assessment (NA) Report was prepared for the purpose of identifying potential needs in the Peterborough to Kingston (the "region") and to recommend which needs a) do not require further regional coordination and can be directly addressed by developing a preferred plan as part of the NA phase and b) require further assessment and regional coordination. The results reported in this NA are based on the input and information provided by the Technical Working Group (TWG) for this region at the time. Updates may be made based on best available information throughout the planning process.

The TWG participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	Peterborough to Kingston Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: September 05, 2024 **END DATE:** December 20, 2024

1. INTRODUCTION

The second Regional Planning cycle for the Peterborough to Kingston Region was completed in May 2022 with the publication of the Regional Infrastructure Plan ("RIP") report. This is the third cycle of Regional Planning for the region.

The purpose of this Needs Assessment ("NA") is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group ("TWG") decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of the region NA and includes:

a) Review and reaffirm needs/plans identified in the previous regional planning cycle RIP (as applicable),

b) Identify any new needs resulting from this assessment,

c) Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,

d) Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is ten years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. Electrical supply to this region is provided by 3 "Three" major Transmission Stations with Autotransformers that feeds, 10 "Ten" step-down Transformer Stations, 8 "Eight" HV Distribution Stations and 5 "Five" Customer transformer Stations.

5. INPUTS/DATA

The TWG comprises of representatives from Local Distribution Companies ("LDC"), the Independent Electricity System Operator ("IESO"), and Hydro One and provides input and relevant information for the region regarding capacity needs, reliability needs, operational issues, and major high-voltage (HV) transmission assets requiring replacement over the planning horizon. The LDCs also capture input from municipalities in the development of their 10-year summer and winter load forecasts.

In accordance with the regional planning process, stakeholder engagement takes place during the IRRP phase.

6. ASSESSMENT METHODOLOGY

The needs assessment's primary objective is to identify the electrical infrastructure needs in the Region over the 10-year planning horizon. A 20-year planning assessment is undertaken in the next phases of regional planning, i.e., IRRP and RIP phases. The assessment methodology includes a review of planning information such as load forecast (which factors various demand drivers and consideration of MEPs and/or CEPs where available), conservation and demand management ("CDM") forecast, distributed generation ("DG") forecast, system reliability and operation, and major HV transmission assets requiring replacement.

A technical assessment of needs is undertaken based on:

a) Current and future station capacity and transmission adequacy;
b) System reliability needs and operational concerns;
c) Major HV transmission equipment requiring replacement with consideration to "right-sizing;" and,
d) Sensitivity analysis to capture uncertainty in the load forecast as well as variability of demand drivers such as electrification.

7. NEEDS

I. Updates on needs identified during the previous regional planning cycle.

The following needs and projects discussed in the region's second cycle RIP have been completed:

- Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
- Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.

- Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle.

The following needs and projects discussed in the region's second cycle RIP are currently underway:

- Otonabee TS 44kV (Station Capacity) – 8 MW of load transfer will be transferred to Dobbin TS in 2025.
- Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
- Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.
- Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
- Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
- Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
- Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by two new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
- Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
- Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
- B5QK (Long-term Capacity need in 2038) – As recommended in the previous cycle IRRP, IESO will re-evaluate this capacity need in next phases of this Regional Planning cycle, when 20 year load forecast will be developed.

II. Newly identified needs in the region

The following are new needs that were identified as part of this assessment:

a) Asset Renewal for Major HV Transmission Equipment

- Cataraqui TS (T1/T2)

b) Transmission Station Capacity

- Dobbin TS
- Gardiner TS
- Napanee TS
- Belleville TS
- Cataraqui TS
- Picton TS
- Hinchinbrooke DS
- Frontenac TS

c) Transmission Line Capacity

- 115 kV B1S line under Q6S contingency

d) System Reliability, Operation and Load restoration

- No new System Reliability, Operation and Load restoration needs identified in this NA.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

The impact of the sensitivity analysis for the high and low growth scenarios identified the following updates to new station capacity needs:

- Sidney TS (2031), Otonabee TS 27.6kV (2026), Otonabee TS 44kV (2028) and 115kV P4S (2031).

These needs will be assessed again during the next phases of this Regional Planning cycle.

9. RECOMMENDATIONS

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Needs which do not require further regional coordination.

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[1] of the regional planning cycle. A list of these needs are as follows:

Needs which require further regional coordination.

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028
Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

[1] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA as potential options in addressing these needs during the IRRP phase.

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1. INTRODUCTION

The second cycle of the Regional Planning process for the Peterborough to Kingston (P to K) Region was completed in May 2022 with the publication of the Regional Infrastructure Plan (“RIP”) report. The RIP report included a common discussion of all the options and recommended plans for preferred wire infrastructure investments to address the near- and medium-term needs.

This Needs Assessment initiates the third regional planning cycle for the P to K Region. The purpose of this Needs Assessment (“NA”) is to:

a) Identify any new needs and reaffirm needs identified in the previous regional planning cycle; and,
b) Recommend which needs:
   i) require further assessment and regional coordination to develop a preferred plan (and hence, proceed to the next phases of regional planning); and,
   ii) do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The planning horizon for this NA assessment is ten years. A flow chart of the Regional Planning Process is shown in Figure 1 below.

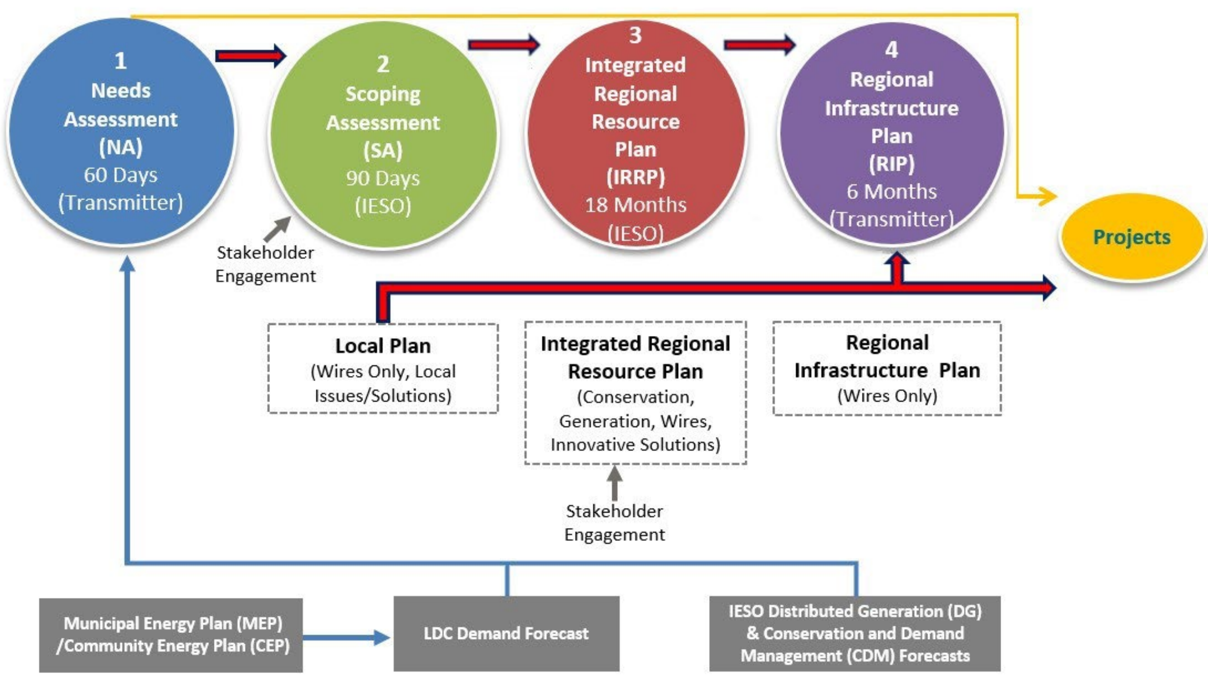


Figure 1: Regional Planning Process

This report was prepared by the Peterborough to Kingston region Technical Working Group(“TWG”), led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies (“LDC”) and the Independent Electricity System Operator (“IESO”). Participants of the TWG are listed below in Table 1.

Table 1: Peterborough to Kingston Region TWG Participants

Sr. no.	Name of TWG Participants
1	Hydro One Transmission (Lead Transmitter)
2	Independent Electricity System Operator
3	Hydro One Distribution
4	Elexicon Energy Inc.
5	Kingston Hydro Corporation
6	Lakefront Utilities Inc.
7	Eastern Ontario Power Inc.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the Regional Planning cycle should be triggered at least once every five years. Due to an increase in load growth in the region, the Technical Working Group (“TWG”) decided that the 3rd Regional Planning cycle be triggered in advance of the five-year period in September 2024.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the Peterborough to Kingston region and includes:

- Review and reaffirm needs/plans identified in the previous cycle RIP (as applicable),
- Identify any new needs resulting from this assessment,
- Recommend which need(s) require further assessment and regional coordination in the next phases of the regional planning cycle to develop a preferred plan; and,
- Recommend which needs do not require further regional coordination (i.e., can be addressed directly between Hydro One and the impacted LDC(s) to develop a preferred plan and/or no

regional investment is required at this time and the need may be reviewed during the next regional planning cycle).

The Technical Working Group TWG may also identify additional needs during the next phases of the planning process, namely Scoping Assessment ("SA"), Integrated Regional Resource Plan ("IRRP"), Local plan (LP) and RIP, based on updated information available at that time.

The planning horizon for this NA assessment is 10 years.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Peterborough to Kingston (P to K) region is comprised of the area roughly bordered geographically by the municipality of Clarington on the West, North Frontenac County on the North, and Lake Ontario on the South. The region includes Frontenac County, City of Kingston, Hasting County, Northumberland County, Peterborough County, and Prince Edward County. The geographical boundaries of the P to K region are shown in Figure 2 below.

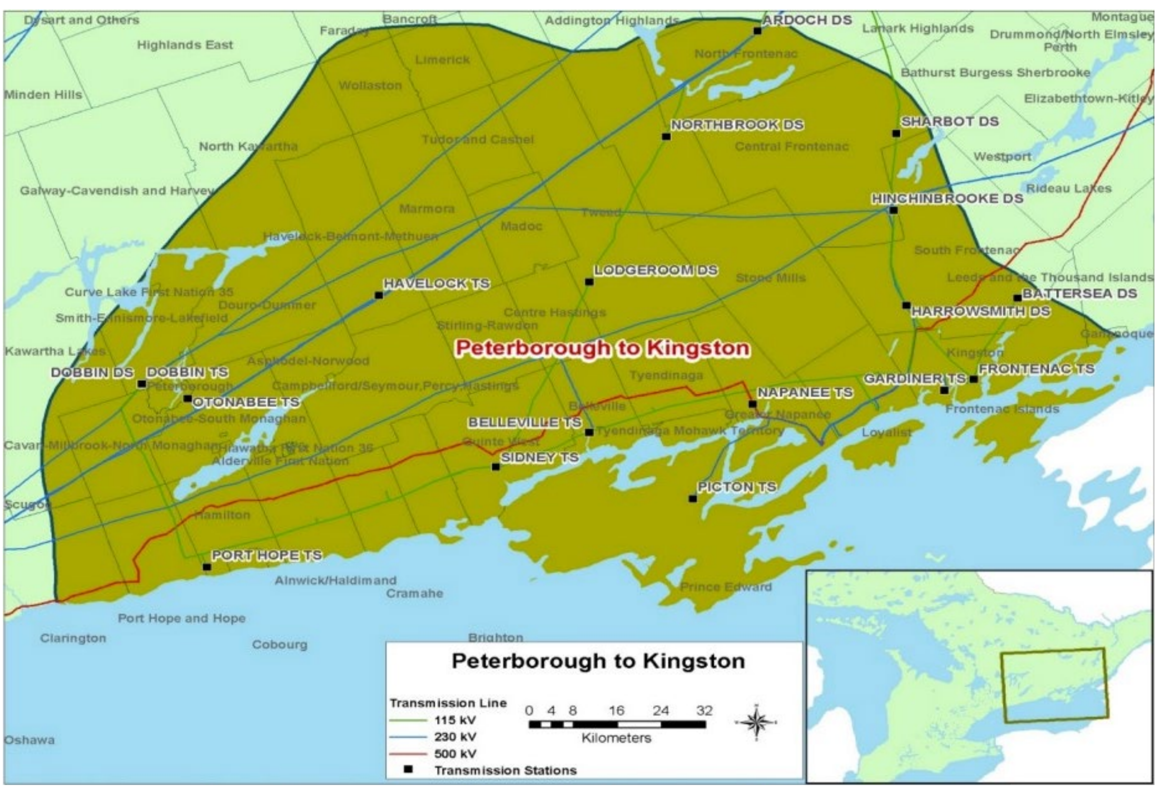


Figure 2: Map of P to K Regional Planning Area

Electrical supply to all five (5) Local Distribution Customers (LDC) listed in table -1 and five (5) Customer Transformer Stations (CTS) in the P to K region is provided by 500/230kV autotransformers at Lennox TS and 230/115kV autotransformers at Cataraqui TS and Dobbin TS through a 230kV and 115kV transmission lines network. There are seven (7) Generation Stations that generates a total of 3474 MW. The 500kV system is part of the bulk power system and is not studied as part of this Needs Assessment.

The details of existing facilities in the region are summarized below and depicted in the single line diagram shown in figure 3.

- 500/230kV Autotransformer: Lennox TS is the major transmission station that connects the 500kV network to the 230kV system via two autotransformers.
- 230/115kV Autotransformer: Cataraqui TS and Dobbin TS are the two (2) transmission stations that connect the 230kV network to the 115kV system via 230/115 kV autotransformers.
- Ten (10) step-down transformer stations and eight (8) High Voltage Distribution Stations (HVDS) are connected to 230 and 115 kV lines that supply load in the Region.
- Five Customer Transformer Stations (CTS) are supplied in the Region.
- Seven Generating stations are also connected.

The circuits and stations names are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the P to K Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
P3S, P4S, Q6S, B1S, Q3K & B5QK.	X1H, X2H, X3H, X4H, X21, X22, H23B, H27H, X1P, C27P, T32H, C25H, T22C, P15C & T25B.	Dobbin TS*, Cataraqui TS*, Lennox TS*, Belleville TS, Dobbin TS, Frontenac TS, Gardiner TS, Havelock TS, Napanee TS, Otonabee TS, Picton TS, Sidney TS, Port Hope TS, CTS -1, CTS-2, CTS-3, CTS-4 & CTS-5.	Seven (7) Generating Stations with total capacity of 3474 MW.

*****Stations with Autotransformers installed

The single line diagram of the Transmission Network of P to K region is shown in Figure 3 below.

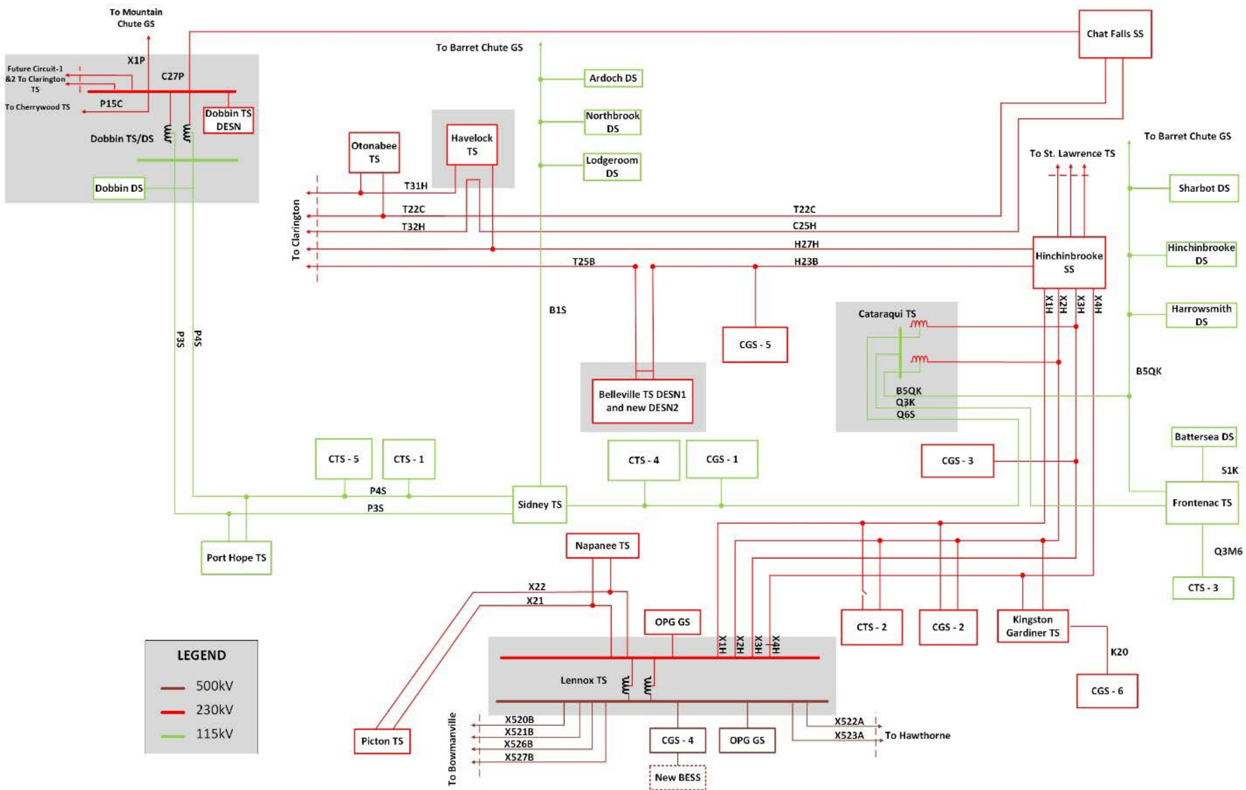


Figure 3: P to K region Transmission Single Line Diagram

5. INPUTS AND DATA

TWG participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the P to K NA. With respect to the load forecast information, the OEB Regional Planning Process Advisory Group (RPPAG) recently published a document called "Load Forecast Guideline for Ontario" in Oct. 2022. The objective of this document is to provide guidance to the TWG in the development of the load forecasts used in the various phases of the regional planning process with a focus on the NA and the IRRP. One of the inputs into the LDC's load forecast that is called for in this guideline is information from Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). The list of all the Municipalities falling under the geographical boundaries of the region are given in Appendix-E.

The information provided includes the following:

- P to K 10-year summer and winter Load Forecasts for all supply stations inclusive of the inputs provided by the municipalities (e.g., through their MEPs & CEPs).
- Known capacity and reliability need, operating issues, and/or major assets requiring replacement/ refurbishment; and

- Planned/foreseen transmission and distribution investments that are relevant to Regional Planning for the P to K region.
- Captured uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments.

6. ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in development of this Needs Assessment:

6.1 Technical Assessments and Study Assumptions

The technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy;
- System reliability and operational considerations;
- Asset renewal for major high voltage transmission equipment requiring replacement with consideration to “right-sizing;” and,
- Load forecast data was requested from industrial customers in the region, and
- This assessment is based on summer and winter peak loads. Three load forecasts were developed i.e., Normal Growth scenario, High and Low Growth scenarios. The High and Low Growth scenarios were developed to conduct a sensitivity analysis to cover unforeseen developments such as, fuel switching, Government policies, higher than expected EV charging trend during peak load conditions, etc.

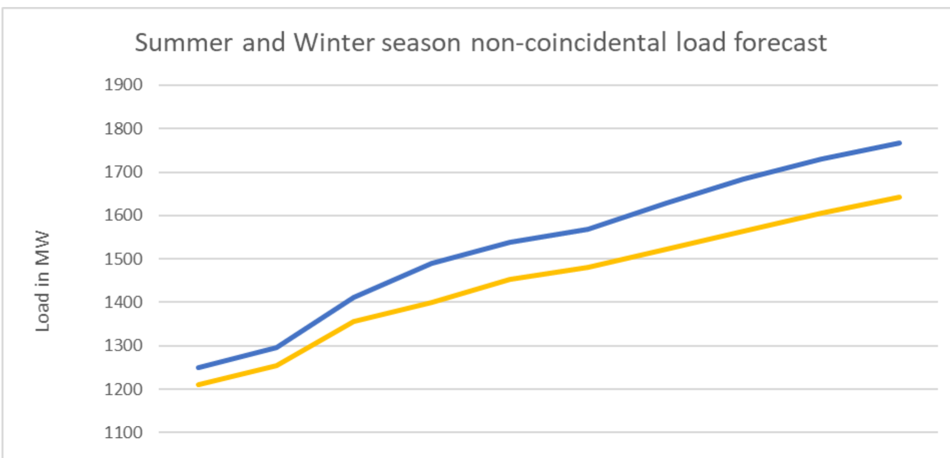
The following other assumptions are made in this report.

- The study period for this Needs Assessment is 2024-2033.
- The Region is winter peaking, but station LTRs are more limiting during the summer season. So, this assessment is based on both summer and winter peak loads.
- Line capacity adequacy is assessed by using coincident peak loads in the area.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station’s normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks.
- Normal planning supply capacity for transformer stations is determined by the Hydro One summer 10-Day Limited Time Rating (LTR) of a single transformer at that station.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).

6.2 Information Gathering Process

6.2.1. Load forecast:

The LDCs provided their load forecasts for summer and winter for all the stations supplying their loads in the P to K region for the 10-year study period including the inputs from the Municipalities such as MEPs and CEPs. The IESO provided a Conservation and Demand Management ("CDM"), and Distributed Generation ("DG") forecast for the P to K region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast growth rates to the weather corrected forecast starting point. The overall 10-year load forecast growth rate for summer season is 3.6% and 4.2% for winter season. The extreme summer and winter weather correction factors were provided by Hydro One. The net extreme summer weather load forecasts were produced by reducing the gross load forecasts for each station by the percentage CDM and then by the amount of effective DG capacity provided by the IESO for that station. It is to be noted that as contracts for existing DG resources in the region begin to expire, at which point the load forecast has a decreasing contribution from local DG resources, and an increase in net demand. This extreme summer and winter weather corrected net load forecast for the individual stations in the P to K region is given in Appendix A. The graphical representation of the regional net non-coincidental load growth for both summer and winter season over the study period is shown in figure 4 below.



	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Summer	1211	1254	1355	1399	1453	1481	1523	1563	1606	1642
winter	1249	1297	1411	1491	1539	1569	1629	1683	1730	1768

Figure 4: P to K region net summer and winter season non-coincidental load

6.2.2. Sensitivity Analysis:

A sensitivity analysis was undertaken by the TWG to capture uncertainty in the load forecast as well as variability of drivers such as electrification. Hence, the NA recommendations are not necessarily linked to sensitivity scenarios; but rather are used to identify any emerging needs for consideration in developing recommendations. The impact of sensitivity analysis for the high and low growth scenarios are provided in section 8 of this report.

6.2.3. Asset Renewal Needs for Major HV Equipment:

List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced based on asset condition assessment, relevant for Regional Planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines. The scope of equipment considered is given in section 7.1.

6.2.4. System Reliability and Operational Issues:

IESO will perform more detailed study to identify system reliability and operational issues in the region during next phases of regional planning.

7. NEEDS

This section describes emerging new needs identified in the P to K Region and/or updates on previously identified needs since the completion of Previous Regional Planning cycle.

Needs that were identified and discussed in the previous regional planning cycle (Regional Infrastructure Plan ("RIP") report) with associated projects that were recently completed and reaffirmed needs that are underway and are briefly described below with relevant updates and will not be discussed further in the report. These projects include:

1. Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2 was completed in 2024.
2. Belleville TS (Asset Renewal) – T1/T2 transformer were replaced by similar 75/100/125 MVA standard step-down transformers in 2021/2022.
3. Cataraqui TS (Supply Capacity) – It was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this RP cycle. This station capacity need should be further assessed in conjunction with Frontenac TS in the next phases of this Regional Planning cycle.
4. Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site. The new DESN is planned to be in service in end of 2026.
5. Frontenac TS (Station Capacity) – Frontenac TS currently supplies Central Kingston and East Kingston but the existing 115kV lines and upstream autotransformers at Cataraqui TS that supply Frontenac TS have reached capacity. As recommended in second cycle RIP, Hydro One

Transmission is working with Utilities Kingston to plan a new 230kV-44kV station in the West Kingston area in the near term, which may be built by the Transmitter or Utilities Kingston. This station capacity need will be further assessed in the next phases of this Regional Planning cycle.

6. Gardiner TS DESN1 (Asset Renewal) – T1/T2 transformer will be replaced by like for like 75/100/125 MVA standard step-down transformers. Planned in-service year for T1 is 2026 and T2 is 2027.
7. Port Hope TS (Asset Renewal) – T3/T4 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2033.
8. Picton TS (Asset Renewal) – T1/T2 transformer will be replaced by like for like 50/67/83 MVA standard step-down transformers. Planned in-service year is 2026.
9. Dobbin TS (Asset Renewal and decommissioning) - T1 and T2 autotransformers are to be replaced by new 150/250MVA units and decommissioning of T5 autotransformer with an expected in-service date in end of 2028.
10. Lennox TS (Asset Renewal) – Ten (10) existing 230kV ABCB & oil breakers to be replaced by new SF6 breakers. Planned in-service year is 2026.
11. Peterborough to Quinte West (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One have started the project to build a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022. Planned in-service year is end of 2029.
12. B5QK (Long-term Capacity need in 2038) – As recommended in the second cycle IRRP, IESO will re-evaluate this capacity need in next phases of current Regional Planning cycle, when 20 year load forecast will be developed.

Note: The planned in-service year for the above projects is tentative and is subject to change.

All near, and mid-term needs that are discussed as a part of this report are summarized in Table 3 below.

Table 3: Near/Mid-term Needs Identified in this NA and/or are updated from previous RIP

Need location	Need description/Update	Previous RIP Report Section	NA Report Section
Asset Renewal Needs			
Cataraqui TS	T1/T2 renewal based on asset condition assessment.	7.2	7.1.1
Transmission Station Capacity Needs			
Dobbin TS (T3/T4)	Projected to reach capacity in 2032	New	7.2.1
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028	7.5 & 7.8	7.2.2
Napanee TS (T1/T2)	Projected to reach capacity in 2026	New	7.2.3
Cataraqui TS	Update on need identified in previous cycle RIP	7.2	7.2.4

Picton TS	Projected to reach capacity in 2026	7.6	7.2.5
Hinchinbrooke DS	Projected to reach capacity in 2028	New	7.2.6
Belleville TS	Capacity limitation due to transmission voltage restrictions	7.3	7.2.7
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle	7.4	7.2.8
Transmission Line Capacity Needs			
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency, high hydro output	New	7.3.1
System Reliability, Operation and Load restoration Needs			
No new system Reliability, Operation and Load restoration need is identified in this NA.			

7.1 Asset Renewal Needs for Major HV Transmission Equipment

In addition to the previously identified asset renewal needs from the second regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the P to K Region. The complete list of major HV transmission equipment requiring replacement in the P to K Region is provided in table 4 in this section. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
- replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
- Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:
- Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

Table 4: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD*
Gardiner TS	T1/T2 replacement with like for like 75/100/125 MVA units.	2027
Port Hope	T3/T4 replacement with like for like 50/67/83 MVA units.	2033
Picton TS	T1/T2 replacement with like for like 50/67/83 MVA units.	2026
Dobbin TS	T1/T2 Autotransformers to be replaced by two bigger 150/250MVA units and decommissioning existing T5.	2028
Lennox TS	Ten (10) 230kV ABCB & Oil breakers to be replaced by new SF6 breakers.	2026
Cataraqui TS	T1 and T2 230/115kV Autotransformers to be replaced with 150/200/250 MVA units.	2034

* The planned in-service year for the above projects is tentative and is subject to change.

7.1.1 Cataraqui TS – T1/T2 Autotransformers

The existing T1/T2, 230/115 kV, 150/200/250 MVA autotransformers were built in 1968 and are identified to be replaced based on asset condition assessment. The existing autotransformers have substandard rating due to internal limitations and will be replaced by similar size modern units which is expected to have a higher LTR. This replacement will also help resolve the station capacity need identified in previous cycle RIP and is discussed in section 7.2.4 of this report. The planned in-service date is 2034.

7.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transforming stations in the P to K Region using the summer and winter non-coincidental peak net load forecasts that were provided by the Technical Working Group. Based on the results, the following Station[2] capacity needs have been identified in the during the study period:

7.2.1 Dobbin TS (T3/T4)

Dobbin TS is located near the city of Peterborough, Ontario, and supplies load to Hydro One Distribution through its two 75/100/125MVA, T3/T4 step down transformers. The 2032 non-coincident peak net load is expected to exceed its summer and winter LTRs of 156 MW and 177 MW, respectively.

While the need for additional capacity is projected toward the end of the study period, it depends on several factors, including whether the load increases as anticipated. There is a possibility that this overload could be managed through load transfers to nearby stations. It is recommended that Hydro One Transmission and Distribution collaborate to address this potential issue, and no regional planning coordination is required at this time.

7.2.2 Gardiner TS (T1/T2)

Gardiner TS DESN 1 is located in city of Kingston, Ontario, and is supplied by 230kV, X2H/X4H circuits and supplies load to Hydro One Distribution and Kingston Hydro Corporation (embedded) currently through its two 75/100/125 MVA, T1/T2 step down transformers. These transformers were identified for replacement in previous regional planning cycle and are planned to be replaced in 2027 and will have a better LTR (~170MW). The non-coincident peak net load summer load at this station is exceeding its LTR of 121 MW now.

Kingston Hydro Corporation has projected significant load growth in 2026, driven by an industrial development project, and again in 2032, due to a customer transitioning from a conventional gas heating system to geothermal heating. These new contributions will lead to exceed the new transformer to exceed its LTRs by 2028. It is recommended that a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.3 Napanee TS (T1/T2)

Napanee TS is located in Greater Napanee area, Ontario, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 101.7 MW and 116.9 MW, respectively.

Hydro One Distribution has projected significant load growth in 2026, driven by two large customers. These new loads are expected to exceed the new transformer LTRs by 2026. However, as these load

[2] Belleville TS and Frontenac TS capacity needs were already identified in the 2nd cycle RP and there are no changes to the recommendations made in the RIP by TWG. Updates to all previously identified needs is provided in beginning of section-7 of this report.

forecasts are not committed load, the station capacity need may be shifted accordingly. It is recommended the load growth shall be monitored and a solution for this additional capacity be identified in the next phase of the regional planning cycle.

7.2.4 Cataraqui TS

Cataraqui TS is a 230/115kV autotransformer station that supplies the 115kV stations in the Eastern sub region of the P to k region. It was recommended upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment performed by Hydro One, the conductor in the 115kV yard was found to be sufficient. T1/T2, 230/115 kV, 150/200/250 MVA autotransformers will be replaced with similar size units in 2034. The new autotransformers are expected have higher LTRs and will further address the issue of overload at the station. The replacement of existing autotransformers is based on asset condition assessment and hence it is recommended that no further regional planning coordination is required at this time.

7.2.5 Picton TS

Picton TS is located in Picton area, Ontario, between Bay of Quinte and Prince Edward Bay, and is supplied by 230kV, X21/X22 circuits and supplies Hydro One Distribution load through its 50/67/83 MVA T1/T2 step down transformers. The 2026 non-coincident peak net load is expected to exceed its summer and winter LTRs of 75 MW and 89 MW, respectively.

The existing T1/T2 transformers have been identified for replacement based on asset condition assessments. The replacement units will be of similar size but will have higher LTRs (~100MW) due to modern designs, which will be enough to supply the load throughout the study period. It is recommended that no further regional planning coordination is required at this time.

7.2.6 Hinchinbrooke DS

Hinchinbrooke DS is located in Central Frontenac area, Ontario and is supplied by 115kV B5QK circuit and supplies Hydro One Distribution Load through its 115/13.2 kV T1 transformer. The 2028 non-coincident peak net load is expected to exceed its winter LTRs of 8.4 MW. The load growth in the area is not significant and can be monitored and addressed within Hydro One Transmission and Distribution. No further regional planning coordination is recommended at this time.

7.2.7 Belleville TS

Belleville TS is located in Belleville area and is supplied by two 230 kV T25B and H23B lines and supplies load to Hydro One Distribution and Elexicon Energy Inc. through its DESN1 two 75/100/125 MVA, 230/44kV, T1/T2 step down transformers. A new Belleville TS DESN2 will be in service by the end of 2026 to address the supply capacity need in the region. Based on the load forecast, and the existing voltage constraints on the transmission lines supplying Belleville TS for a H23B contingency at the Belleville TS, limiting the total loading by the year 2028-2031, depending on the load and LV configuration at Belleville TS DESN2. This undervoltage cannot be mitigated without a partial loss of load at DESN2 post 2028 loading. Therefore, it is recommended to conduct a comprehensive assessment in the next phases of the regional planning cycle to manage this need as well as a full bulk planning study as identified in the previous regional planning cycle.

7.2.8 Frontenac TS

Frontenac TS is located in Kingston area and is supplied by two 115kV B5QK and Q3K lines and supplies Hydro One Distribution, Utilities Kingston, and Eastern Ontario Power Inc. load through its two 50/67/83 MVA, 230/44kV, T3/T4 stepdown transformers. As recommended in second cycle RIP, Hydro One Transmission is working with Utilities Kingston to plan a new station in the area in the near term, which may be built by the Transmitter or the LDC. The Frontenac station capacity need should be further assessed in the next phases of this Regional Planning cycle.

7.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period 2024-2033 for the 230kV and 115kV Transmission line circuits in the P to K Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

7.3.1 115kV B1S

B1S is a long 145km 115kV single-circuit radial line which extends between Barrett Chute GS and Sidney TS and serving Ardoch DS, Northbrook DS and Lodgeroom DS in between. The supply capacity of the line could exceed its continuous rating in in the near to medium timeline following a contingency on Q6S line and high hydro output from generators in the region. The B1S line is limited by a low sag temperature which is the main reason of this line could be overloaded. Hydro One Transmission will perform an internal assessment to see if there is room for improving the sag temperature to address the issue in near time, but it is also recommended to do a full assessment during the next phases of this regional planning cycle.

7.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period 2024-2033 to cater this need**.** Based on the results, no new significant system reliability, operating and restoring issues have been identified for this Region.

8. SENSITIVITY ANALYSIS

The objective of a sensitivity analysis is to capture uncertainty in the load forecast as well as variability of electric demand drivers to identify any emerging needs and/or advancement or deferment of recommended investments. The TWG determined that the key electric demand driver in the P to K region to be considered in this sensitivity analysis is the new Industrial load and expansion of urban areas from municipalities, electric vehicle (EV) penetration, and unforeseen electrification which would cause the load to increase at a faster rate than shown in the forecast; or the potential delay in some projects which could result in less demand than anticipated.

The TWG reviewed the new Industrial load and expansion of urban areas from municipalities, EV scenarios, and any unforeseen electrification needs to develop high demand growth forecasts by applying 50% additional growth to the growth rate on the extreme summer and winter corrected Normal Growth net load forecasts. The low growth scenario was obtained by reducing the growth rate by 50%.

The normal and high growth forecasts are shown in Appendix A.

The impact of sensitivity analysis for the high and low growth scenario identified the following updates or new station capacity needs:

Table 5: Impact of Sensitivity Analysis on Station/Line capacity needs in the region

Sr.no.	Need Identified	Normal Growth Scenario	High Growth Scenario	Low Growth Scenario
1	Dobbin TS (T3/T4)	2032	2029	2032
2	Gardiner TS (T1/T2)	Current and 2028	Current	Current and 2033
3	Gardiner (T3/T4)	NA	NA	NA
4	Napanee TS (T1/T2)	2026	2026	NA
5	Picton TS	2026	2026	NA
6	Hinchinbrooke DS	2028	2027	NA
7	Sydney TS	NA	2031	NA
8	Otonabee TS 25.6kV	NA	2026	NA
9	Otonabee TS 44kV	NA	2028	NA
10	B1S	2028	2028	2028
11	P4S	NA	2031	NA
12	Belleville TS (undervoltage)	2028	2027	NA
13	Frontenac TS	2027	2026	2030

In addition, the radial tap from 230kV circuits X2H and X4H serving Kingston through Gardiner TS DESN1 and DESN2 have a summer Long Term Emergency (LTE) rating of about 395 MW. Current normal summer loading forecast for Gardiner TS DESN1 and DESN2 total 293 MW by 2033, leaving about 102 MW of thermal capacity remaining. If the area experiences a higher load growth as per the scenario above and/or large transmission customer connection up to 100 MWs, there will be capacity need in this area.

The sensitivity analysis identified the additional capacity needs at towards the end of the study period. The sensitivity analysis and these needs will be assessed again during the next phases of this Regional Planning cycle.

9. CONCLUSION AND RECOMMENDATION

The Technical Working Group's recommendations to address the needs identified are as follows:

Needs that do not require further assessment and regional coordination: These needs are local in nature and do not have a regional impact. They can be addressed by a straightforward transmission and/or distribution wires solution. They do not require investment in any upstream transmission facility or require Leave to Construct (i.e., Section 92) approvals. These needs generally impact a limited number of LDCs and can be addressed directly between Hydro One and the LDC(s) to develop a preferred local plan. A list of these needs are as follows:

Table 7: Needs which do not require further regional coordination

Need location	Need description
Asset Renewal Needs	
Cataraqui TS	T1/T2 renewal based on asset condition assessment.
Station Capacity Needs	
Dobbin TS (T3/T4)	Projected to reach capacity in 2032
Cataraqui TS	Update on need identified in previous cycle RIP
Picton TS	Projected to reach capacity in 2026
Hinchinbrooke DS	Projected to reach capacity in 2028

Needs that require further assessment and regional coordination: These needs may have broader regional impacts and require further assessment and coordination during the next phases[3] of the regional planning cycle. A list of these needs are as follows:

Table 8: Needs which require further regional coordination

Need location	Need description
Station Capacity Needs	
Gardiner TS (T1/T2)	Projected to reach capacity now and 2028

[3] Non-wires options are further considered (i.e. incremental to CDM and DG that is considered in this NA) as potential options in addressing these needs during the IRRP phase.

Napanee TS (T1/T2)	Projected to reach capacity in 2026
Belleville TS	Capacity limitation due to transmission voltage restrictions
Frontenac TS	Further assess the capacity need in the next phases of this Regional Planning cycle
Transmission Lines Capacity Needs	
115 kV B1S line	Projected to reach capacity in 2028, under Q6S contingency with high hydro generation

List of LDC(s) to be involved in further regional planning phases:

- Hydro One Distribution
- Elexicon Energy Inc.
- Kingston Hydro Corporation
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.

List of LDC(s) which are not required to be involved in further regional planning phases:

- None

10. REFERENCES

[1] P to K 2nd cycle Regional Infrastructure Plan ("RIP") report (issue May 27, 2022)

[2] P to K 2nd cycle Integrated Regional Resource Plan report (issue November 4, 2021)

[3] Gatineau Corridor End-of-Life Study published in December 2022.

[4] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[5] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. October 1, 2024)

[6] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. March 27, 2024)

[7] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Summer and Winter Weather Adjusted Net Load Forecast

Table A.1: P to K Region – Summer Non-Coincident- Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.7	2.8	2.8	2.8
Battersea DS	T1/T2	21.9	8.9	9.2	9.1	9.1	9.0	9.1	9.1	9.2	9.2	9.3	9.3
Belleville TS	T1/T2	170.05	164.9	166.6	175.4	183.5	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	55.3	68.0	72.5	77.5	84.1	91.1	101.1
Dobbin DS	T1/T2	16.9	15.9	15.9	15.9	6.2	6.2	6.6	7.0	7.4	7.8	8.2	8.4
Dobbin TS	T3/T4	156.8	70.1	72.7	82.2	111.1	119.9	127.5	133.9	145.9	155.2	159.8	163.9
Frontenac TS	T3/T4	109.3	98.6	102.3	105.2	109.2	113.1	115.8	118.3	123.6	128.2	131.7	135.3
Gardiner TS	T1/T2	121.6	130.3	125.3	128.2	162.6	168.0	170.5	171.9	175.8	177.7	195.4	200.8
Gardiner TS	T3/T4	111.2	46.8	57.1	57.4	57.7	57.9	79.9	84.9	86.6	88.4	90.3	92.3
Harrowsmith DS	T1/T2	21.9	15.8	15.7	15.5	15.6	15.5	15.6	15.7	15.7	15.8	15.9	16.1
Havelock TS	T1/T2	86.4	63.1	62.5	65.2	64.8	64.5	65.0	65.1	65.6	66.0	66.3	66.7
Hinchinbrooke DS	T1	6.8	6.1	6.5	6.4	6.4	6.4	6.4	6.4	6.4	6.5	6.5	6.5
Lodgeroom DS	T1/T2	21.9	8.6	8.5	8.6	8.6	8.6	8.6	8.5	8.6	8.5	8.6	8.6
Napanee TS	T1/T2	101.7	66.6	75.2	82.4	108.4	110.9	105.2	108.3	111.6	113.0	114.3	118.2
Northbrook DS	T1	8.4	6.0	5.9	5.9	5.9	5.8	5.8	5.9	5.9	5.9	6.0	6.0
Otonabee TS 27.6kV	T1/T2	92.52	81.7	82.6	83.9	74.5	75.3	75.7	76.0	76.4	76.9	77.5	78.2
Otonabee TS 44kV	T1/T2	97.2	81.2	82.0	77.3	79.3	82.3	85.0	85.7	88.3	89.7	90.9	91.6
Picton TS	T1/T2	75.6	64.3	69.7	71.8	79.2	85.7	88.4	90.8	93.1	95.6	97.5	99.4
Sharbot DS	T1	6.2	3.9	4.0	4.0	4.0	3.9	4.0	4.0	4.0	4.0	4.0	4.1
Sidney TS	T1/T2	111.8	80.6	83.0	88.4	95.8	96.2	100.2	100.3	100.7	102.6	103.2	103.9
Port Hope TS	T1/T2	122.6	52.0	54.2	58.3	59.6	60.3	61.1	61.5	65.2	72.2	73.0	73.9

Port Hope TS	T3/T4	101.7	73.4	73.7	74.5	74.7	74.8	74.9	74.9	75.0	75.3	75.7	76.3
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.2: P to K Region – Winter Non-Coincident – Normal Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.3	3.4	3.4	3.4	3.5	3.5	3.5
Battersea DS	T1/T2	24.3	11.9	12.2	12.2	12.3	12.3	12.4	12.4	12.4	12.5	12.5	12.6
Belleville TS	T1/T2	183.4	158.5	159.9	172.9	184.0	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4	0.0	0.0	0.0	0.0	59.2	75.6	82.2	90.0	98.2	107.3	119.6
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.4	10.5	11.6	12.6	13.7	14.7	15.8	16.3
Dobbin TS	T3/T4	177.7	80.2	83.5	93.5	105.6	117.5	127.8	136.3	164.7	177.0	183.0	188.4
Frontenac TS	T3/T4	123.5	101.8	110.0	112.7	116.3	120.0	122.6	124.7	129.4	132.2	135.2	138.3
Gardiner TS	T1/T2	143.5	128.4	123.4	126.5	159.8	165.3	168.1	169.4	173.2	175.1	192.0	197.4
Gardiner TS	T3/T4	138.7	41.5	51.7	52.1	52.6	80.0	85.8	87.5	89.4	91.3	93.3	95.5
Harrowsmith DS	T1/T2	24.3	19.7	20.2	20.5	20.7	20.9	21.1	21.2	21.4	21.5	21.7	21.9
Havelock TS	T1/T2	97.2	78.2	80.5	81.5	82.7	83.5	84.3	84.7	85.3	87.5	88.3	89.2
Hinchinbrooke DS	T1	8.6	8.2	8.4	8.5	8.6	8.7	8.7	8.8	8.9	8.9	9.0	9.1
Lodgeroom DS	T1/T2	24.3	11.1	11.4	11.5	11.7	11.8	12.0	12.0	12.1	12.4	12.5	12.7
Napanee TS	T1/T2	116.9	81.0	89.0	95.9	120.2	122.7	117.8	120.7	121.9	123.2	124.4	125.7
Northbrook DS	T1	10.8	8.7	8.9	9.0	9.1	9.2	9.3	9.4	9.5	9.5	9.6	9.8
Otonabee TS 27.6kV	T1/T2	109.8	54.9	55.8	57.1	58.1	58.9	59.3	59.5	59.7	60.0	60.3	60.8
Otonabee TS 44kV	T1/T2	109.8	77.8	78.8	74.0	76.1	79.2	81.9	82.6	85.1	94.3	95.3	96.0
Picton TS	T1/T2	89.1	60.9	68.6	70.8	78.3	85.0	87.8	90.2	92.5	94.9	96.6	98.6

Sharbot DS	T1	8.4	5.4	5.6	5.7	5.7	5.8	5.8	5.9	5.9	6.0	6.0	6.1
Sidney TS	T1/T2	111.8	77.1	76.6	82.4	96.8	97.2	102.4	103.1	104.5	107.3	108.4	109.6
Port Hope TS	T1/T2	139.7	61.3	63.4	67.4	68.7	69.6	70.6	71.0	74.5	81.0	81.8	82.7
Port Hope TS	T3/T4	115.9	75.6	76.1	77.1	77.6	77.9	78.3	78.3	78.5	78.9	79.3	79.9
CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Table A.3: P to K Region Summer Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	7.8	2.7	2.7	2.8	2.8	2.8	2.8	2.8	2.8	2.9	2.9	3.0
Battersea DS	T1/T2	21.9	8.9	9.4	9.5	9.6	9.7	9.7	9.7	9.8	9.9	10.0	10.1
Belleville TS	T1/T2	170.05	164.9	167.4	180.7	192.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	170.05	0.0	0.0	0.0	0.0	70.4	89.5	96.3	103.8	113.7	124.2	139.2
Dobbin DS	T1/T2	16.9	15.9	15.9	16.0	6.0	6.0	6.6	7.2	7.8	8.4	9.1	9.3
Dobbin TS	T3/T4	156.8	70.1	73.9	88.2	131.6	144.8	156.1	165.8	183.8	197.8	204.7	210.7
Frontenac TS	T3/T4	109.3	98.6	104.2	108.5	114.5	120.3	124.4	128.2	136.1	143.0	148.2	153.6
Gardiner TS	T1/T2	121.6	130.3	137.7	142.1	193.7	201.7	205.5	207.6	213.4	216.3	242.9	251.0
Gardiner TS	T3/T4	111.2	46.8	62.2	62.6	63.1	63.4	96.4	103.9	106.4	109.1	112.0	115.0
Harrowsmith DS	T1/T2	21.9	15.8	16.0	16.3	16.5	16.7	16.8	16.9	16.9	17.1	17.4	17.6
Havelock TS	T1/T2	86.4	63.1	63.8	67.9	68.4	69.0	69.8	69.9	70.6	71.2	71.7	72.2
Hinchinbrooke DS	T1	6.8	6.1	6.7	6.7	6.8	6.9	6.9	6.9	7.0	7.0	7.1	7.1
Lodgeroom DS	T1/T2	21.9	8.6	8.7	8.7	8.8	8.8	8.8	8.9	8.9	9.0	9.1	9.2
Napanee TS	T1/T2	101.7	66.6	79.5	90.3	129.4	133.0	141.5	146.1	151.1	153.1	155.1	161.0
Northbrook DS	T1	8.4	6.0	6.1	6.1	6.2	6.2	6.3	6.3	6.4	6.4	6.5	6.5
Otonabee TS 27.6kV	T1/T2	92.52	81.7	83.0	85.0	99.0	100.2	100.8	101.3	101.8	102.6	103.5	104.5
Otonabee TS 44kV	T1/T2	97.2	81.2	82.4	89.6	92.7	97.2	101.2	102.3	106.1	108.3	110.0	111.1
Picton TS	T1/T2	75.6	64.3	72.4	75.5	86.6	96.5	100.4	104.1	107.5	111.2	114.1	117.0
Sharbot DS	T1	6.2	3.9	4.1	4.1	4.2	4.2	4.2	4.2	4.3	4.3	4.3	4.4
Sidney TS	T1/T2	111.8	80.6	84.1	92.3	103.4	104.0	109.9	110.1	110.7	113.5	114.5	115.6
Port Hope TS	T1/T2	122.6	52.0	55.3	61.5	63.3	64.4	65.6	66.2	71.7	82.3	83.5	84.9
Port Hope TS	T3/T4	101.7	73.4	73.8	75.1	75.4	75.5	75.7	75.7	75.9	76.3	76.9	77.7
CTS -1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS -2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS -3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9

CTS -4			0	0	0	0	0	0	0	0	0	0	0
CTS -5			0	0	0	0	0	0	0	0	0	0	0

Table A.4: P to K Region – Winter Non-Coincident – High Growth Net Load Forecast

Transformer Station Name	DESN ID	LTR (MW)	Forecast Starting Point (Extreme Weather Corrected)	Near Term Forecast (MW)					Medium Term Forecast (MW)				
				2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ardoch DS	T1	10.5	3.3	3.3	3.3	3.3	3.4	3.4	3.5	3.5	3.6	3.6	3.7
Battersea DS	T1/T2	24.3	11.9	12.3	12.4	12.5	12.6	12.6	12.6	12.7	12.7	12.8	12.9
Belleville TS	T1/T2	183.4	158.5	160.6	180.2	196.7	140.0	140.0	140.0	140.0	140.0	140.0	140.0
Belleville New DESN	T3/T4	183.4		0.0	0.0	0.0	79.6	104.1	114.0	125.8	138.1	151.6	170.1
Dobbin DS	T1/T2	21.6	10.3	10.4	10.4	10.5	10.5	12.2	13.7	15.3	16.9	18.6	19.2
Dobbin TS	T3/T4	177.7	80.2	85.2	100.2	118.2	136.1	151.5	164.3	206.9	225.4	234.4	242.4
Frontenac TS	T3/T4	123.5	101.8	114.0	118.1	123.6	129.0	133.0	136.2	143.2	147.4	151.8	156.6
Gardiner TS	T1/T2	143.5	128.4	135.9	140.5	190.4	198.7	202.9	204.9	210.6	213.4	238.8	246.9
Gardiner TS	T3/T4	138.7	41.5	56.8	57.4	58.1	99.2	107.9	110.5	113.3	116.2	119.3	122.5
Harrowsmith DS	T1/T2	24.3	19.7	20.5	20.9	21.2	21.5	21.8	22.0	22.2	22.4	22.7	23.0
Havelock TS	T1/T2	97.2	78.2	81.7	83.2	84.9	86.1	87.4	88.0	88.8	92.1	93.3	94.7
Hinchinbrooke DS	T1	8.6	8.2	8.5	8.6	8.8	8.9	9.0	9.1	9.2	9.3	9.4	9.5
Lodgeroom DS	T1/T2	24.3	11.1	11.6	11.8	12.0	12.2	12.4	12.5	12.7	13.0	13.2	13.5
Napanee TS	T1/T2	116.9	81.0	93.0	103.3	139.8	143.6	150.9	155.3	157.0	159.0	160.7	162.8
Northbrook DS	T1	10.8	8.7	9.0	9.2	9.3	9.5	9.6	9.7	9.8	10.0	10.1	10.3
Otonabee TS 27.6kV	T1/T2	109.8	54.9	56.3	58.2	59.8	61.0	61.5	61.8	62.1	62.5	63.1	63.8
Otonabee TS 44kV	T1/T2	109.8	77.8	79.3	86.5	89.7	94.2	98.4	99.5	103.2	116.9	118.5	119.6
Picton TS	T1/T2	89.1	60.9	72.5	75.8	87.0	97.0	101.2	104.8	108.3	111.9	114.5	117.4
Sharbot DS	T1	8.4	5.4	5.7	5.8	5.9	6.0	6.0	6.1	6.2	6.2	6.3	6.4
Sidney TS	T1/T2	111.8	77.1	77.8	86.5	108.1	108.6	116.5	117.5	119.6	123.8	125.5	127.2
Port Hope TS	T1/T2	139.7	61.3	64.5	70.4	72.5	73.8	75.2	75.8	81.0	90.8	92.0	93.4
Port Hope TS	T3/T4	115.9	75.6	76.3	77.9	78.6	79.0	79.6	79.7	80.0	80.5	81.2	82.1

CTS - 1			2.0	2.0	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1	2.1
CTS - 2			26.1	26.1	26.3	26.6	26.8	27.1	27.3	27.5	27.7	28.0	28.2
CTS - 3			10.3	10.3	10.3	10.4	10.5	10.6	10.6	10.7	10.8	10.8	10.9
CTS - 4			5	5	5	5	5	5	5	5	5	5	5
CTS - 5			8	8	8	8	8	8	8	8	8	8	8

Appendix B: Lists of Step-Down Transformer Stations

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Ardoch DS (T1)	115	B1S
2	Battersea DS (T1/T2)	115	S1K
3	Belleville TS (T1/T2)	230	T25B, H23B
4	Dobbin DS (T1/T2)	115	P3S, P4S
5	Dobbin TS (T3/T4)	115	Q20H, Q20A
6	Frontenac TS (T3/T4)	115	B5QK, Q3K
7	Gardiner TS (T1/T2)	230	X4H, X2H
8	Gardiner TS (T3/T4)	230	X2H, X4H
9	Harrowsmith DS (T1/T2)	115	B5QK
10	Havelock TS T1/T2	115	T31H, H27H
11	Hinchinbrooke DS (T1)	115	B5QK
12	Lodgeroom DS (T1/T2)	115	B1S
13	Napanee TS (T1)	230	X21, X22
14	Northbrook DS (T1)	115	B1S
15	Otonabee TS (T1/T2) 27.6	230	T22C, T31H
16	Otonabee TS (T1/T2) 44	230	T22C, T31H
17	Picton TS (T1/T2)	230	X21, X22
18	Sharbot DS (T1)	115	B5QK
19	Sidney TS (T1/T2)	115	Q12AT, Q6S
20	Port Hope TS (T1/T2)	115	P3S, P4S
21	Port Hope TS (T3/T4)	115	P3S, P4S

Appendix C: Lists of Transmission Circuits

No.	Connecting Stations	Circuit ID	Voltage (kV)
1	Hinchinbrooke SS – Lennox TS	X1H, X2H, X3H, X4H	230
2	Picton TS – Lennox TS	X21, X22	230
3	Belleville TS – Hinchinbrooke SS	H23B	230
4	Hinchinbrooke SS – Havelock TS	H27H	230
5	Dobbin TS – Chenaux TS	X1P	230
6	Dobbin TS – Chat Falls GS	C27P	230
7	Clarington TS – Havelock TS	T32H	230
8	Chat Falls GS – Havelock TS	C25H	230
9	Clarington TS – Chat Falls GS	T22C	230

10	Cherrywood TS – Dobbin TS	P15C	230
11	Clarington TS – Belleville TS	T25B	230
12	Dobbin TS – Sidney TS	P3S, P4S	115
13	Cataraqui TS – Sidney TS	Q6S	115
14	Barrett Chute TS – Sidney TS	B1S	115
15	Cataraqui TS – Frontenac TS	Q3K	115
16	Cataraqui TS – Frontenac TS to Barrett Chute TS	B5QK	115

Appendix D: List of LDC's

No.	Name of LDC
1	Hydro One Distribution
2	Elexicon Energy Inc.
3	Kingston Hydro Corporation
4	Lakefront Utilities Inc.
5	Eastern Ontario Power Inc.

Appendix E: List of Municipalities in the P to K Region

No.	Name of Municipality
1	Municipality of Clarington
2	City of Kingston
3	County of Frontenac
4	Township of North Frontenac
5	Township of South Frontenac
6	Township of Central Frontenac
7	Township of Frontenac Islands
8	City of Belleville
9	City of Quinte West
10	Municipality of Centre Hastings
11	Municipality of Hastings Highlands
12	Municipality of Marmora and Lake
13	Municipality of Tweed
14	Town of Bancroft
15	Town of Deseronto
16	Township of Carlow/Mayo
17	Township of Faraday
18	Township of Limerick
19	Township of Madoc
20	Township of Stirling-Rawdon
21	Township of Tudor & Cashel
22	Township of Tyendinaga
23	Township of Wollaston
24	Municipality of Brighton
25	Town of Cobourg
26	Municipality of Port Hope
27	Municipality of Trent Hills
28	Township of Alnwick/Haldimand
29	Township of Cramahe
30	Township of Hamilton
31	City of Peterborough
32	Township of Asphodel-Norwood
33	Township of Cavan Monaghan
34	Township of Douro-Dummer
35	Township of Havelock-Belmont-Methuen
36	Township of North Kawartha
37	Township of Otonabee-South Monaghan
38	Township of Selwyn

39	Municipality of Trent Lakes
40	Prince Edward
41	Town of Greater Napanee
42	Township of Addington Highlands
43	Township of Loyalist
44	Township of Stone Mills

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	KiloVolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MEP	Municipal Energy Plan
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Peterborough to Kingston

Scoping Assessment Outcome Report

April 28, 2025

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

1. Introduction

This Scoping Assessment Outcome Report is produced as part of the Ontario Energy Board's ("OEB" or "Board") regional planning process and sets out the planning approach to address electricity needs that have been identified in the Peterborough to Kingston region. This is the third cycle of planning for the region, and the process was initiated in September 2024. The Needs Assessment ("NA") is the first step in the regional planning process and was carried out by the Study Team led by Hydro One Networks Inc. ("Hydro One"), and the Technical Working Group (TWG) consisting of Hydro One, the Independent Electricity System Operator (IESO) and the Local Distribution Companies. The Needs Assessment Report was finalized and published on December 20, 2024, and identified a list of needs that either require further regional coordination or can be addressed by local planning. This information was an input to this Scoping Assessment Outcome Report.

During the Scoping Assessment, TWG reviewed the nature and timing of all the known needs in the region to determine the most appropriate planning approach, as well as geographically grouping the needs where beneficial to efficiently carry out the study. The planning approaches considered include:

- **An Integrated Regional Resource Plan ("IRRP") –** through which a greater range of options, including non-wires alternatives, are to be considered and/or closer coordination with communities and stakeholders is required.
- **A Regional Infrastructure Plan ("RIP")** led by the transmitter – which considers more straight-forward wires only option with limited engagement; or
- **A local plan** undertaken by the transmitter and affected local distribution company (LDC) – for which no further regional coordination is required.

This Scoping Assessment Report:

- Lists the needs requiring more comprehensive planning, as identified in the Needs Assessment report
- Reassesses the areas that need to be studied and the geographic grouping of the needs (if
- required)
- Determines the appropriate regional planning approach and scope where a need for regional
- coordination or more comprehensive planning is identified
- Establishes a Terms of Reference for an IRRP and/or wires planning, if required
- Establishes the composition of the Technical Working Group, if required

2. Study Team

The Scoping Assessment was carried out with the following participants:

- Independent Electricity System Operator (“IESO”)
- Hydro One Networks Inc. (“Hydro One Transmission”)
- Hydro One Networks Inc. (“Hydro One Distribution”)
- Elexicon Energy Inc.
- Lakefront Utilities Inc
- Eastern Ontario Power Inc.
- Utilities Kingston

3. Overview of Region and Background

3.1 Overview of the Peterborough to Kingston Region

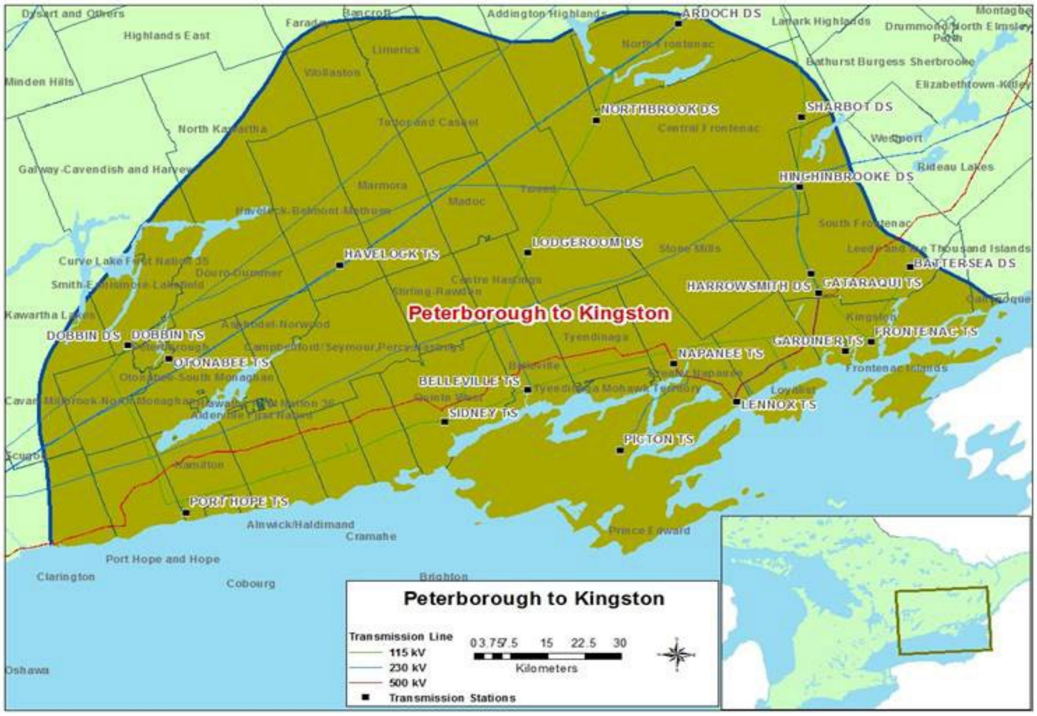
The Peterborough-Kingston region is located in eastern Ontario and is composed of the following: Municipality of Clarington located in the Regional Municipality of Durham, the City of Kingston, the County of Frontenac consisting of the Townships of North Frontenac, South Frontenac, Central Frontenac, and Frontenac Islands, The City of Belleville, City of Quinte West, Prince Edward County, the County of Hastings including the Municipalities of Centre Hastings, Hastings Highlands, Marmora and Lake, Tweed, the, Carlow/Mayo, Faraday, Limerick, Madoc, Stirling-Rawdon, Tudor & Cashel, Tyendinaga, Wollaston, and the Towns of Bancroft and Deseronto, the County of Northumberland consisting of the Municipalities of Brighton, Port Hope, Trent Hills, the Town of Cobourg, and the Townships of Alnwick/Haldimand, Cramahe, and Hamilton, the City of Peterborough and the County of Peterborough including the Townships of Asphodel-Norwood, Cavan Monaghan, and the Townships of Douro-Dummer, Havelock-Belmont-Methuen, North Kawartha, Otonabee-South Monaghan, Selwyn, and the Municipality of Trent Lakes, the County of Lennox and Addington including the Town of Greater Napanee, and the Townships of Addington Highlands, Loyalist, and Stone Mill.

Within the region, Peterborough and Kingston are the two largest population centres. The region also comprises several Indigenous communities including Alderville First Nation, Algonquins of Ontario, Algonquins of Pikwakanagan, Chippewas of Beausoleil First Nation, Chippewas of Georgina Island First Nation, Chippewas of Rama First Nation, Curve Lake First Nation, Hiawatha First Nation, Mississaugas of Scugog Island First Nation, Mohawks of the Bay of Quinte, Kawartha Nishnawbe, Métis Nation of Ontario.

For electricity planning purposes, the planning region is defined by electricity infrastructure boundaries, not municipal boundaries. The electricity infrastructure supplying the Peterborough-Kingston region is shown in

Figure **1**. Hydro One owns the transmission assets in this region.

Figure 1 | Overview of the Peterborough to Kingston region



The region is supplied by four local distribution companies (LDC). Eastern Ontario Power serves over 3,500 distribution customers in Gananoque, Ontario. Lakefront Utilities serves 10,000 distribution customers across the Town of Cobourg and the Village of Colborne. Utilities Kingston serves 28,000 distribution customers in Central Kingston. Hydro One Distribution supplies distribution customers in the surrounding areas of the region. These four LDCs receive power at the step-down transformer stations and distribute it to end users, i.e., industrial, commercial and residential customers.

Electrical supply to the Peterborough-Kingston region is provided through a network of 230 kilovolt (kV) and 115 kV circuits supplied by two 500/230 kV transformers at Lennox Transformer Station (TS), and four 230/115 kV transformers: two at Cataraqui TS and two at Dobbin TS. There are 10 step-down transformer stations in the area: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS. There are also eight Distribution Stations (DS) in the region: Dobbin DS, Ardoch DS, Northbook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS. Finally, there are five Customer Transformer Stations (CTS) in the region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Shannonville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.

There are two major thermal generating stations located in the region, injecting at the 500 kV and 230 kV voltage levels: Lennox GS (~2,150 MW) and Napanee GS (~1,000 MW). In addition, there are over 400 MW of transmission-connected wind and solar generation facilities across the region. The 115 kV system between Dobbin TS and Frontenac TS is also connected via long 115 kV circuits to Barrett Chute GS located outside the region on the Madawaska River. Finally, there is a total of 189 MW of distribution-connected generation spread across the region.

As per Hydro One's Needs Assessment, this area has net extreme weather winter peak demand of approximately 1,249 MW, which occurred in the year 2024. This area is expected to grow to approximately 1,768 MW by the year 2033. Furthermore, the net extreme weather summer peak demand was approximately 1,211 MW in the year 2024. This is expected to grow to approximately 1,642 MW by the year 2028. This corresponds to a growth rate of 4.6 percent per year in the winter and 4 percent in the summer.

3.2 Background of the Previous Planning Process

The first cycle of the regional planning process for Peterborough to Kingston was completed in February 2015 with the Needs Assessment concluding that there was no need at that time for further integrated planning for the region and that localized wires-only plans be developed for the needs identified.

The second cycle of was completed in 2021; during this regional planning process the TWG decided an IRRP was required for the region as several near-, mid- and long-term needs were identified and a range of options (including non-wire alternatives) had to be evaluated as part of the solution. As a result of the recommendations made within the second cycle, projects are currently in-progress to address these needs.

Table 1 lists the projects that have been completed since the region's second cycle.

Table 1 | List of completed projects

Project	Completion Date
Gardiner TS (Station Capacity) – Load transfer (~10MW) from DESN1 to DESN2	2024
Belleville TS (Asset Renewal) – T1/T2 transformers were replaced by similar 75/100/125 MVA standard step-down transformers	2021/2022

Table 2 covers projects that are currently underway since the region's second cycle RIP.

Table 2 | List of projects currently underway

Project	Expected Completion Date
Otonabee TS 44kV (Station Capacity) – 8 MW load transfer to Dobbin TS	2025
Belleville TS (Station Capacity) – Build new Belleville DESN #2 with two 75/100/125 MVA transformers at the existing Belleville TS site	2026
Gardiner TS DESN 1 (Asset Renewal) – T1/T2 to be replaced with two 75/100/125 MVA transformers	2026/2027
Durham-Kawartha Power Line (P15C 230kV & Q6S 115kV Supply Capacity) - Hydro One has initiated building a new 230kV double circuit line from Clarington TS to Dobbin TS as recommended in Gatineau Corridor End-of-Life Study published in December 2022	2029
Dobbin TS (Asset Renewal/Decommissioning) – Autotransformers T1 and T2 are expected to be replaced with two 150/250MVA along with the decommissioning of T5.	2028
Kingston MTS (Station Capacity) New 230kV DESN with two 75/100/125MVA transformer expected to serve load growth in Central Kingston.	2030
Port Hope TS (Asset Renewal) – Transformers T3/T4 to be replaced like for like with two 50/67/83 MVA units.	2033

During this regional planning cycle, the TWG will monitor and review the status of ongoing projects, specifically assessing the progress of previous recommendations and impact of asset renewals on system limits.

3.3 Needs Identified in the 2024 Needs Assessment

For this third cycle of regional planning, the NA identified several needs in the Peterborough-Kingston region based on a 10-year demand forecast and their most up-to-date asset sustainment plans. Additionally, the regional working group participants have considered the characteristics of the transmission and distribution systems in the region, the potential for regional coordination, and the opportunities for stakeholder and community engagement, to develop the following regional needs.

3.3.1 Station Capacity Needs

Station capacity refers to a stations ability to convert and deliver power from the transmission system to an LDC's distribution system. The NA identified several stations expected to exceed their current capacity as described in Table 3.

Table 3 | Station capacity needs based on normal growth scenario

Station	Need Year
Gardiner TS (T1/T2)	Current*/2028
Napanee TS (T1/T2)	2026
Picton TS	2026
Hinchinbrooke DS	2028
Dobbin TS (T3/T4)	2032
Frontenac TS	2027

*Gardiner TS is projected to exceed its station capacity today; planned transformer replacements are expected to mitigate the station overload. Based on the NA load forecast, the new transformers will exceed station capacity in 2028.

When the high growth forecast is considered, there are additional station capacity needs at Otonabee TS and Sidney TS in the year 2026 and 2031, respectively.

3.3.2 Load Security and Restoration Needs

Load security criteria places limits on the total amount of load interrupted following major transmission outages. Load restoration criteria describe timeframes by which power must be restored to loads interrupted due to a major transmission outage. No load security or restoration needs were identified as part of this cycle's NA.

3.3.3 Supply Capacity Needs

Supply capacity needs identify the transmission system's ability to supply power through the transmission lines and auto-transformers to local distribution systems being serviced within the region. The NA identified several supply capacity needs, as summarized in **Table 4**.

Table 4 | Supply Capacity Needs

Need	Need Description
Belleville TS	Transmission voltage issues under contingency, currently evaluated under Eastern Ontario Bulk Planning Study.
B1S (Q6S Out)	B1S is expected to exceed its thermal limits when Q6S is out of service during high hydro generators output.
Cataraqui TS	Review supply/station capacity in this IRRP.
X2H	Potential supply capacity need with Kingston MTS and a large transmission customer connection.
X4H	Potential supply capacity need with Kingston MTS and a large transmission customer connection.
B5QK	Re-evaluate supply capacity need in this IRRP.
Q3K	Potential supply capacity need under high growth or large transmission customer connection.

During the high growth forecast, an additional supply capacity needs exists on circuit P4S in the year 2031.

For the Cataraqui TS, it was recommended to upgrade the existing copper conductor on secondary side of auto transformers. However, in an assessment the conductor was found to be sufficient and an update to this recommendation was suggested, which will be discussed in this regional planning cycle.

In the second regional planning cycle, there was a long-term need identified for the circuit B5QK (in the year 2038). As recommended in the second cycle IRRP, IESO will re-evaluate this capacity need in next phases of current Regional Planning cycle, when 20-year load forecast will be developed. Given the potential of a large customer connection in Central Kingston, the supply capacity of both Q3K and B5QK will be reviewed.

In addition, the radial tap from 230kV circuits X2H and X4H serving Kingston through Gardiner TS DESN1 and DESN2 are expected to approach their summer Long Term Emergency (LTE). Given the Kingston MTS project that is underway and the potential of a large transmission customer connection, there will be a potential supply capacity need.

3.3.4 End-of-life Asset Replacement Needs

When assets are determined to be approaching end-of-life, an assessment needs to be performed on whether the asset should be replaced, refurbished, upgraded, retired, or another solution be developed. The NA newly identified asset renewal needs, as shown in **Table 5**.

Table 5 | Stations with asset renewal needs

Station	End of Life Year	Description
Cataraqui TS	2034	T1/T2 expected to be replaced 2034
Gardiner TS	2027	Transformers at DESN1 expected to be replaced 2026-2027.
Port Hope TS	2033	T3/T4 planned to be replaced 2033
Dobbin TS	2028	Replacement of T1/T2 and decommissioning T5 for 2028.
Lennox TS	2026	Ten 230 kV ABCB & Oil breakers to be replaced by new SF6 breakers.
Picton TS	2026	T1/T2 planned to be replaced 2026

3.3.5 Analysis of Needs and Planning Approach

The regional participants have discussed the needs in the Peterborough-Kingston region. They considered several factors before determining the recommended planning approach, including the potential for regional coordination and for a wide range of solutions - including conservation, generation, and new technologies, wires infrastructure and non-wires solutions.

Needs identified through the NA were reviewed during the Scoping Assessment to determine whether a Local Plan, Regional Infrastructure Plan, or Integrated Regional Resource Plan regional planning approach is most appropriate.

An Integrated Regional Resource Plan is recommended for the Peterborough to Kingston region. The following sections outline the summary of needs that will be reviewed in the IRRP.

3.3.6 Summary of Needs to be Reviewed in the IRRP

Identified needs that will be reviewed in the IRRP are summarized in Table 6; their locations are shown in Figure 2.

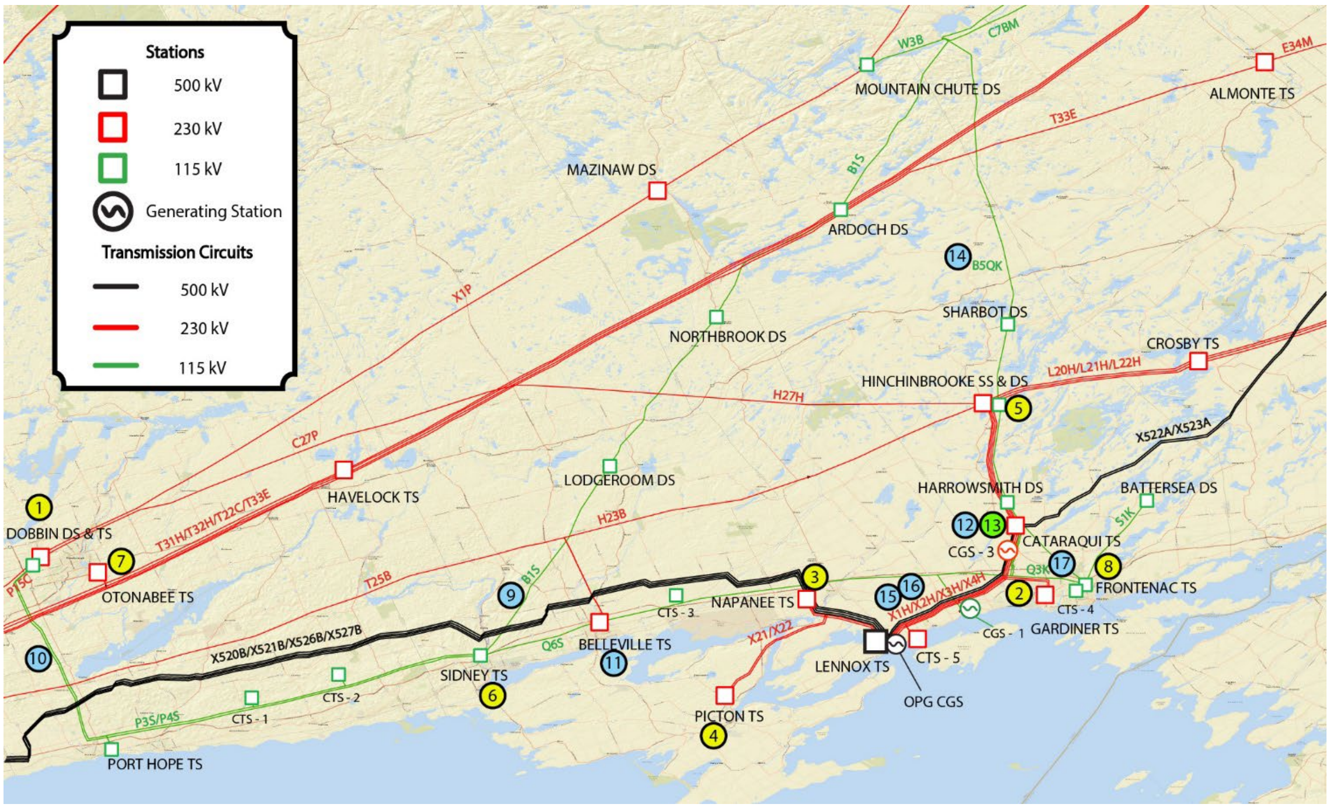
Table 6 | Summary of the needs to be reviewed in the IRRP

#	Need	Need Type	Estimated Timing in N/A	Need Description
1	Dobbin TS (T3/T4)	Station Capacity	2032	Station Overload
2	Gardiner TS (T1/T2)	Station Capacity	Current/2028	Transformers are planned to be replaced but based on the needs assessment forecast, there is an overload in 2028.
3	Napanee TS (T1/T2)	Station Capacity	2026	Station Overload
4	Picton TS	Station Capacity	2026	Station Overload, transformers are expected to be replaced and could meet forecasted load.
5	Hinchinbrooke DS	Station Capacity	2028	Station Overload
6	Sidney TS*	Station Capacity	2031	Station Overload
7	Otonabee TS*	Station Capacity	2026	Station Overload
8	Frontenac TS	Station Capacity	2027	Station Overload
9	B1S (Q6S Out)	Supply Capacity	-	During high demand, the transmission line is expected to exceed its thermal limits when Q6S is out of service.
10	P4S*	Supply Capacity	-	Review the need with TWG during IRRP.
11	Belleville TS	Supply Capacity	-	Transmission voltage issues, currently being evaluated under Eastern Ontario Bulk Planning Study, including the timing of the need.
12	Cataraqui TS	Supply Capacity	-	Review the need with TWG during IRRP.
13	B5QK	Supply Capacity		Review the need with TWG during IRRP.
14	X2H	Supply Capacity	-	Potential supply capacity need with the connection of Kingston MTS and a large transmission customer.
15	X4H	Supply Capacity	-	Potential supply capacity need with the connection of Kingston MTS and a large transmission customer.

16	Q3K	Supply Capacity		Potential supply capacity need under high growth or large transmission customer connection.
17	Cataraqui TS	End-of-life Asset Replacement	2034	T1/T2 expected to be replaced 2034

*When high growth forecast is considered, there are station capacity needs at Otonabee TS and Sidney TS in the year 2026 and 2031 as well as supply capacity needs on circuit P4S in the year 2031.

Figure 2 | Geographic location of needs to be reviewed in the IRRP



4. Conclusion and Next Steps

This Scoping Assessment concludes that:

- Based on the available information, an IRRP will be undertaken for the Peterborough to Kingston region;
- The number and potential linkages between the station capacity, supply capacity, and end-of-life requirements as stated in the summary **Table 6** above require an IRRP;
- The recommendations from the previous planning cycle should be assessed and evaluated;
- The composition of the IRRP Working Group will include the IESO, Hydro One Transmission, Hydro One Distribution, Elexicon Energy Inc., Lakefront Utilities Inc., Eastern Ontario Power Inc., Kingston Hydro.
- Given the significant anticipated scope of the study, the full 18-month timeline for completion of the IRRP is expected to be required; and
- The Peterborough to Kingston IRRP will co-ordinate its findings with the East Bulk Study, and vice-versa.

All IRRPs include opportunities for engagement with local communities and stakeholders, as well as include discussion of any local initiatives focused on energy and/or reducing GHG emissions, and how the IRRP can coordinate with any plans. This could include Community Energy Plans, Net-Zero strategies, or similar. Particular attention will be paid to opportunities for information sharing and/or coordination of goals and outcomes.

The Terms of Reference for the Peterborough-Kingston IRRP are attached in Appendix B.

Appendix 1 – List of Acronyms

Acronym	Definition
CDM	Conservation and Demand Management
CGS	Customer Generating Station
CTS	Customer Transformer Station
DER	Distributed Energy Resources
DG	Distributed Generation
DS	Distribution Station
FIT	Feed-in-Tariff
GTA	Greater Toronto Area
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
MTS	Municipal Transformer Station
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SS	Switching Station
TS	Transformer Station

Appendix 2 – Terms of Reference

1. Introduction and Background

Peterborough to Kingston is one of the 21 electricity planning regions in Ontario as identified through the Ontario Energy Board's (OEB) formalized Regional Planning Process. These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for Peterborough to Kingston Integrated Regional Resource Plan ("IRRP").

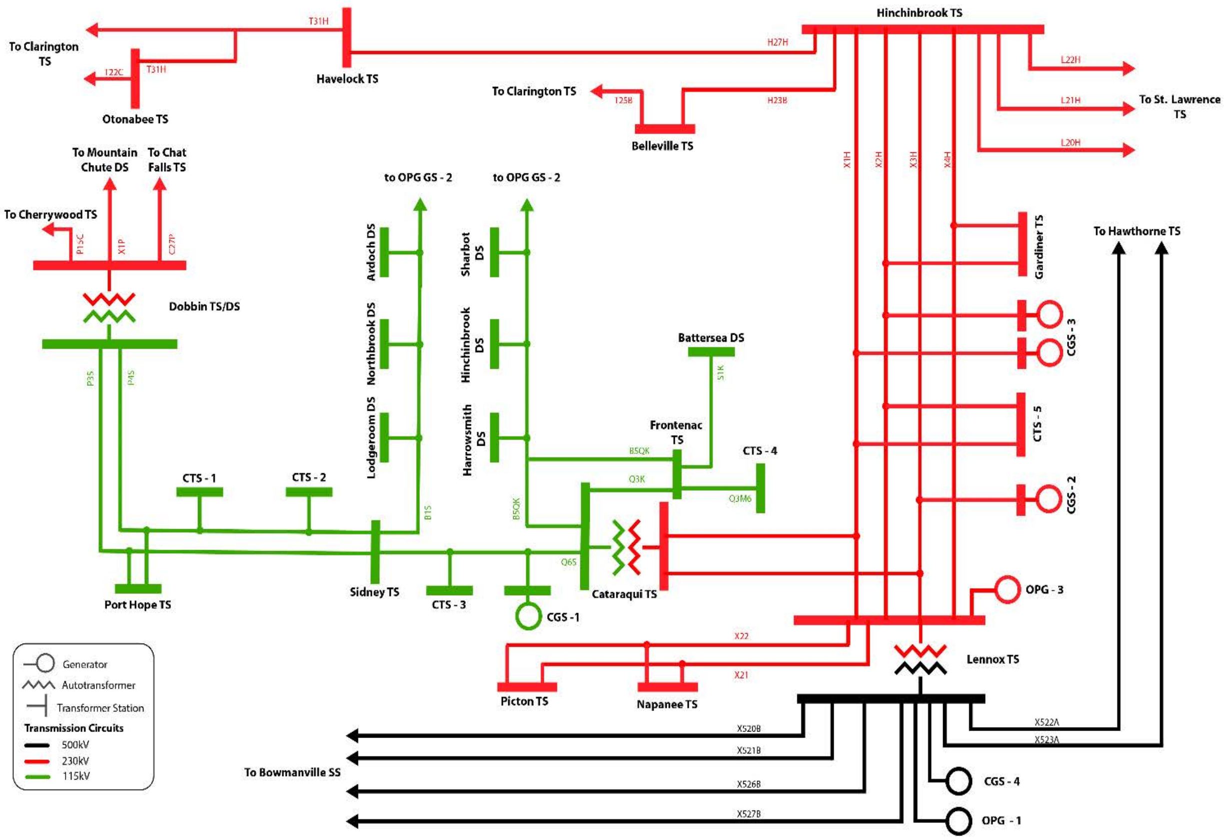
2. Electrical System of the Peterborough to Kingston area

Electrical supply to the Peterborough to Kingston Region ("Region") is provided through a network of 230 kV and 115 kV circuits supplied by 500/230 kV autotransformers at Lennox Transformer Station (TS) and 230/115 kV autotransformers at Cataraqui TS and Dobbin TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3. The 500 kV system is part of the bulk power system and is not studied as part of this IRRP:

- Lennox TS is the major transmission station that connects the 500 kV network to the 230 kV system via two 500/230 kV autotransformers.
- Cataraqui TS and Dobbin TS are the transmission stations that connect the 230 kV network to the 115 kV system via 230/115 kV autotransformers.
- Ten step-down transformer stations supply the Peterborough to Kingston load: Dobbin TS, Port Hope TS, Sidney TS, Picton TS, Otonabee TS, Havelock TS, Belleville TS, Napanee TS, Gardiner TS, and Frontenac TS.
- There are also eight Distribution Stations that supply load in the Region: Dobbin DS, Ardoch DS, Northbrook DS, Lodgeroom DS, Hinchinbrooke DS, Harrowsmith DS, Sharbot DS, and Battersea DS.
- Five Customer Transformer Stations (CTS) are supplied in the Region: TransCanada Pipelines Cobourg CTS, TransCanada Pipelines Belleville CTS, Enbridge Pipelines Hilton CTS, Lafarge Canada Bath CTS, and Novelis CTS.
- There are 7 existing transmission connected generating stations in the Region as follows:
  - Lennox GS is a 2000 MW natural gas-fired station connected to Lennox TS
  - NPIF Kingston GS is a 130 MW gas-fired cogeneration facility that connects to 230 kV circuits X1H and X2H near Lennox TS
  - Wolfe Island GS is a 198 MW wind farm connected to circuit X4H near Gardiner TS
  - Napanee GS is a 910 MW gas-fired plant connected to Lennox TS to the 500 kV system.
  - Kingston Solar CGS is a 100 MW solar generation facility connected to 230 kV circuit X2H
  - Stone Mills CGS is a 60 MW solar generation facility connected to 230 kV circuit H23B
  - Amherst Island CGS is a 76 MW wind farm connected to 115 kV circuit Q6S

Figure 3 | Single line diagram of Peterborough to Kingston Region



3. Objectives

The Peterborough to Kingston Area IRRP will assess the adequacy of electricity supply to customers in the Region and will develop a set of recommended actions to maintain reliability of supply to the Region over the next 20 years (2025-2045). Specifically, this IRRP will:

- Assess the adequacy of electricity supply to customers in the Peterborough to Kingston Region over the next 20 years;
- Determine whether a need exists to initiate development work or fully commit infrastructure investments (wires or non-wires) in this planning cycle;
- Assess potential risks & uncertainties over the longer term and identify near-term actions to manage/mitigate these risks, where applicable;
- Develop an implementation plan that maintains flexibility to accommodate changes in key assumptions over time. The implementation plan should identify actions for near-term needs, preparation work for mid-term needs, and the planning direction for long-term needs; and
- Inform Local Distribution Companies' ("LDC") OEB rate filings.

4. Scope

This IRRP, developed with the Technical Working Group ("TWG"), will consist of an integrated plan to meet the needs of the region. The plan will assess all capacity, restoration and sustainment needs in the area and incorporate input from community engagement activities.

The IRRP process will consist of the following activities:

- Develop an updated 20-year demand forecast for the region.
- Evaluate previously identified needs and identify any new needs.
- Perform an assessment of options that meet each need identified. Options are evaluated using criteria including, but not limited to, technical feasibility, economics, reliability performance, environmental and social factors. The options analysis will be divided into groupings based on the priority/timing of the needs, any known lead time information, and the depth of analysis required.
- Development of the recommendations and implementation plan.

Publication of the IRRP report documenting the assessment, including the near, mid, and long-term needs, recommendations and implementation plan.

5. Data and Assumptions

The plan will consider the following data and assumptions, as applicable:

Demand forecast

- Historical peak demand in the region and historical weather correction for median and extreme conditions. The region's coincident demand and station level non-coincident demand will be forecasted to identify both the location and timing of reliability issues.
- Potential future load customers
- Gross peak demand forecast scenarios by station under normal growth and as needed, high and low growth.
- Peak demand forecast for transmission-connected customers

Conservation and Demand Management (CDM)

- LDC CDM plans
- Verified LDC results and progression towards OEB conservation targets, and any other CDM programs/opportunities in the area
- LDC customers' conservation forecasts
- Conservation potential studies, if available
- Load segmentation data for each TS based on customer type (residential, commercial, industrial)

Local supply resources

- Existing local generation, including distributed generation ("DG"), district energy, customer-based generation, Non-Utility Generators and hydroelectric facilities as applicable
- Existing or committed renewable generation from Feed-in-Tariff ("FIT") and non-FIT procurements
- Future district energy plans, combined heat and power, energy storage, or other generation proposals

Relevant local plans

- LDC Distribution System Plans
- Community Energy Plans and Municipal Energy Plans
- Municipal Growth Plans
- Any transit plans impacting electricity use

Criteria, codes and other requirements

- Ontario Resource and Transmission Assessment Criteria ("ORTAC")
    - Supply capability
    - Load security
    - Load restoration requirements
- NERC and NPCC reliability criteria, as applicable

  - OEB Transmission System Code
  - OEB Distribution System Code
  - Reliability considerations, such as the frequency and duration of interruptions to customers
- Other applicable requirements

Existing system capability

- Transmission line ratings as per transmitter records
- Transformer ratings (10-day LTR) as per asset owner records
- Load transfer capability for restoration during transmission system outages and/or for transmission level capacity needs
- Technical and operating characteristics of local generation

End-of-life asset considerations/sustainment plans & end of expected service life information

- Transmission assets
- Distribution assets

Other considerations, as applicable.

6. Technical Working Group (“TWG”)

The following are the LDCs in the region:

- Elexicon Energy Inc.
- Utilities Kingston
- Lakefront Utilities Inc.
- Eastern Ontario Power Inc.
- Hydro One Networks Inc. (Distribution)

The TWG consists of the LDC stated above as well as the Independent Electricity System Operator (“IESO”) and Hydro One Networks Inc. (Transmission).

Authority and Findings

Each entity involved in the study will be responsible for complying with regulatory requirements as applicable to the actions/tasks assigned to them under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

7. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended to, and adopted by, the provincial government to enhance the regional planning and siting processes in 2013. These recommendations were subsequently referenced in the

2013 Long Term Energy Plan. As such, the TWG is committed to conducting plan-level engagement throughout the development of the Peterborough-Kingston IRRP.

Engagement will consist of meetings with municipalities and Indigenous communities within the region, Indigenous communities who may have an interest in the region and the Métis Nation of Ontario to discuss regional planning, the development of the Peterborough-Kingston IRRP, and integrated solutions.

Engagement will continue throughout the development and completion of the IRRP.

8. Activities, Timeline and Primary Accountability

Table A-1 | Summary of IRRP timelines and activities

	Activity	Lead Responsibility	Deliverable(s)	Start – End Date
1	**Commence IRRP Process** - Prepare terms of reference considering stakeholder input - Kick-off meeting with working group members	*IESO*	- Finalized Terms of Reference	April-May 2025
2	**Develop the Planning Forecast for the Region**			
	- Establish historical peak demand information	*IESO*	- Long-term planning forecast scenarios	April – July 2025
	- Establish historical weather correction, median and extreme conditions	*IESO*		
	- Establish gross peak demand forecast and if applicable/need be, high/low growth scenarios	*LDCs*		
	- Establish existing, committed and potential DG	*LDCs*		
	- Establish near- and long-term conservation forecasts	*IESO*		
	- Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions – for the purpose of analyzing transmission system**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	April – July 2025

	needs and identifying options for addressing needs			
4	**Complete system studies to identify needs over a twenty-year period** - Develop load flow base case, including system assumptions as identified in the key assumptions - Apply reliability criteria as defined in ORTAC to demand forecast scenarios - Confirm and refine the need(s) and timing/load levels	*IESO, Hydro One Transmission*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Aug - Nov 2025
5	**Develop Options and Alternatives**			
	Develop conservation options	*IESO and LDCs*	- Develop flexible planning options for forecast scenarios - Deliverables staged according to the three phases	Dec 2025-Feb 2026
	Develop local generation options	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options	*Hydro One, and LDCs*		
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Develop portfolios of integrated alternatives	*All*		
	Technical comparison and evaluation	*All*		
6	**Plan and Undertake Community & Stakeholder Engagement**			
	- Early engagement with local municipalities and Indigenous communities within the Region, First Nation communities who may have an interest in the Region, and the Métis Nation of Ontario	*All*	- Community and Stakeholder Engagement Plan - Input from local communities	Q3/Q4 2025
	- Develop communications materials	*All*		Q4 2025-Q1 2026
	- Undertake community and stakeholder engagement	*All*		
	- Summarize input and incorporate feedback	*All*		

7	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	March -May 2026
8a	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	June-August 2026
8b	**Review & publish IRRP report**	*IESO*	-	August-Oct 2026

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Audit Report

Ontario Regulation 22/04 Sections 4 to 8

May 23, 2025

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Prepared For:

Lakefront Utilities Inc.

Table of Contents

1. Audit Scope & Summary

This audit report was prepared for Lakefront Utilities Inc. (LUI), which distributes electricity in the municipalities of Cobourg and Colborne, serving approximately **11,139** residential, commercial, and industrial customers. The scope of this audit involved processes concerning eight (8) municipal substations, 4.16kV, 27.6 kV, and 44kV overhead and underground primary and secondary lines. The distributor contracts out a portion of its work to qualified contractors, and such work was included within the scope of the audit. LUI employs 15 regular staff.

The auditor, Ted Olechna, has a Lead QMS Auditor Certificate (ISO 9001:2015). Ted is registered with the Professional Engineers of Ontario and has over 35 years of experience working in various capacities at Ontario Hydro/Hydro One in Ontario, as well as a Director at ESA. He is an approved auditor by the Electrical Safety Authority (ESA) to conduct this audit according to Ontario Regulation 22/04 (Regulation) requirements for EPI.

ESA has identified that this year, audits could be performed in person or remotely. Mark Turney, Principal Consultant, has agreed to an in-person audit. Audit meetings were conducted in person. Records, plans, and standard design drawings were made available at the meetings, and emails.
The audit was conducted on May 7, 2025, including the period required for documentation review and verification of the control environment. Additional time was required to prepare this report.

The auditor declares himself to be independent from LUI and the work to be audited, and free of any potential threats to the auditors' independence, including self-interest, self-review, advocacy, familiarity, and intimidation.

The audit covered the period from March 1, 2024, to February 28, 2025.
The scope of the audit covered the following processes and departments:

- Review of the responses to the issues from previous audits (if applicable)
- Maintenance and Operations
- Purchasing
- Engineering / Design
- Construction and Inspection
- Health and Safety
- LUI's Construction Verification Program (CVP)

The audit was conducted in accordance with the requirements of Sections 4 – 8 of the Regulation

The processes documented within the CVP and associated procedures were followed, personnel were interviewed, and records were reviewed to confirm the implementation of the program.

1.1 Opening Meeting

The opening meeting was held in the morning on May 7, 2024:

- To explain the audit process, deal with any concerns, answer questions, and rework the schedule if necessary

1.2 Closing Meeting

The closing meeting was held in the afternoon on May 7, 2024

1.3 Participants

Individuals who have participated in the opening and closing meetings and other audit sections:

Mark Turney
Christopher Turney
Jamie Lace
Christopher MacDonald
Danielle Wakelin
Jessica Lantz
Scott Webster

1.4 Observations

- Preventive Maintenance and inspection programs for equipment up to 750V not part of the distribution system, overhead/underground primary & secondary distribution lines and municipal substations comply with Appendix ‘C’ of OEB’s Distribution System Code. P.O. reviewed for inspection programs (infrared inspections, tree trimming, vegetation control, oil testing for gas analysis, and pest control). W.O. issued for required corrective actions was signed off by competent persons with “no undue hazard statement”.
- No “Certificate of Deviation Approval” issued during the audit period.
- LUI has 5 locations where a 3-phase, 3-wire solidly grounded WYE system is present. The plan going forward is to complete the remaining in 2025 and following year/s.
- No new major equipment was approved during the audit period.
- Record of Inspections and Partial and final Certificate is identified on the plans.
- CVP identifies staff positions and not names
- CVP training every year and was given to staff on **February 25, 2025**
- LUI participates with local utilities (Fire Department, Police, EMS, the Town, and Union Gas.) on annual emergency planning

- Relationship with Oshawa Hydro is ongoing
- Staffing changes due to departures were identified
- The processes documented within the CVP and associated procedures were followed, personnel were interviewed, and records were reviewed to confirm the implementation of the program.

1.5 Management Response to ESA

The ESA will request a copy of this audit report. Management may be asked to prepare a response to the audit findings.

ESA will respond directly to LUI on receiving the report. An audit review meeting with ESA may take place. The audit findings may be reviewed, and any item that may require action, along with the LUI's action plan and timelines. If actions are required, LUI may be asked to submit a progress report to ESA.

1.6 Auditor Opinion

It is the opinion of this auditor that LUI is in compliance with the requirements of O. Reg 22/04 Section 4, 5, 6, & 7.

Client

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Supervisor, Engineering
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Cobourg, ON K9A 4L3

Auditor

Ted Olechna, P. Eng. .
AESI Acumen Engineered Solutions Int'l Inc.
5575 North Service Road, Suite 401
Burlington, Ontario, L7L 6M1

Appendix 1

Audit Results and Checklist

Audit Findings

Legend: NA – Not Applicable C – Complies NI – Needs Improvement NC – Non-Compliance

Reg. Sect.	Audit Plan / Requirement	Audit Results	NA	C	NI	NC
4(3)	A maintenance and inspection program for equipment up to 750 volts not part of distribution to ensure proper operation and safety (ancillary equipment) (Maintenance and inspection schedules, logs, checklists)	Inspections and PM low voltage ancillary equipment. • Municipal street lighting in Cobourg is maintained by the City of Cobourg and in Colborne by the City of Colborne, not a subsidiary of LUI.	X	X		
4(4)	A maintenance and inspection program for overhead primary and secondary distribution lines to ensure proper operation and safety • Maintenance schedule • Maintenance records • Asset management program	Inspection and PM overhead system. • Asset management system and condition assessment. • Physical maps of the system in work vehicles • GIS updated and available to field staff, printed • Inspection of overhead lines using maps, and the information is manually recorded into GIS. • Cobourg is divided in 3 areas, cycles every 3 years • Colborne is divided in 2 areas, and it follows a 3-year cycle. One year no inspections were performed • Tree trimming follows the same schedule. • contractor does tree trimming. • Ontario line trimming – purchase order reviewed • 80% of the system is overhead • Overhead primary lines inspection is done by Jamie (staff) o Downgrounds are a key item that is cut. Implemented a heavier guard with more attachment points (nails) • Station visual inspection is done by Jamie monthly • Contractor performs Infrared annually.		X		

		o Boldstar – IR company. • 2 locations had minor heating. Scheduled to be reviewed and corrected in 2025 • Primary and secondary line patrols 3-year cycle – 1/3 of the City of Cobourg was patrolled during the audit. • Colborne was not done, will be done in 2025 • Customer lines close to trees o Inform customer that they need tree trimming • Pole testing is performed once a year following a three-year cycle for a 1/3. Based on 5 5-year cycle • No poles were inspected, o 3-year cycle on a 5-year time frame. o Wood poles are mainly installed, o A few polymers are replaced when needed • Voltage conversion and overhead rebuild. o Installing a replacement system to be built to 27.6 and to be completed by 2028 • Porcelain insulators replacement with polymeric during rebuilds and as required. Part of the overhead inspection, and removing old to replace the 4.16 kV 27.6 kV retrofit • Replacement program for aluminum brackets with porcelain insulators, replaced with fiberglass and polymer insulators, due to salt and snow accumulation • NO PCB equipment. • Copper theft is still an issue; reinstall copper as needed o Multi-ground system • LUI has 5 locations with a 3-phase, 3-wire solidly grounded WYE system. The plan going forward is to complete the remaining in 2025 and following year/s.				

		Observations; • Inspection and PM records were available and reviewed.				
4(5)	A maintenance, inspection and testing program for underground primary and secondary distribution lines to ensure proper operation and safety • Maintenance schedule • Asset management program • Maintenance records	Inspection and PM underground system. • Asset management system and condition assessment. • 20% of the system is underground • New subdivision designed by external engineers • No Inspection in 2024. • Reporting annually for 1/3 of the system, in 2024 were none as 2 were done in 2023 • Pole guard replacement due to damage and theft of copper. • Underground is pretty good, no major maintenance. • Voltage conversion from 4.16kV to 27.6kV is ongoing • SF6 switchgear inspected on 1/3 increment . • Perform a 3-year rotation to replace batteries, • One railroad crossing, 3-year cycle. Not in 2024 • Dip pole inspection during line patrol. • No PCB equipment Observations: Inspection and PM records available.		X		
4(6)	A maintenance, inspection, and testing program for distribution stations to ensure proper operation and safety • Maintenance schedule • Asset management program • Maintenance records	Inspection and PM substations. • Asset management system and condition assessment. • Vegetation control twice a year by a contractor. • No PCB equipment. • Oil sampling for gas analysis annually by a contractor.		X		

		• No annual maintenance of 1/3 of the stations. Put off till 2025
		• Stations are checked monthly by LUI competent person.
		  o Monthly substation inspections (lighting, ventilation, heating, batteries, battery chargers, visual inspections of transformers, fences, and grounds).
		• Circuit breakers and Relays testing during substation shutdown maintenance
		• One railroad crossing, inspection 3–year cycle. Not in 2024
		• Customer-owned substation maintained by customer
		  o LUI provides isolation. ~6 isolations, mostly 44KV from H-1
		  o Connection authorization from ESA to energize
		• Weed control by MATACAST
		  o Spring and fall
		• Company on retainer to assist/work on station issues that come up.
		• KPC is on contract.
		
		Inspection and PM records available and reviewed				

6	Distribution equipment approved when approved by certification or field inspection; or approved under Rule of Distributor • Documented outline of equipment approval process including identification of competent persons, • review of test reports • List of approved major equipment up-to-date and reference to standards • Major equipment specifications approved by a competent person or P. Eng. • Approval records • Non-major equipment – Good Utility Practice • Receiving inspection • Pre-regulation equipment - GUP	LUI's equipment approval procedures are documented and approved by the President and CEO. LUI is a member of USF. • LUI uses USF-approved equipment listed on their website. Any new major equipment approvals are by a consulting engineer. • No new major equipment was approved during the audit period.		X		
6(1)(a)	Specifying equipment approved by certification or field evaluation	Staff is aware of the need to specify approved equipment.		X		
6(1(a)	Checking that the supplied ancillary equipment ordered is approved by certification or field evaluation	Staff is aware of the need to check for equipment approval markings.		X		
6(1)(b)	Major distribution equipment approval under Rule of the Distributor: • Meets industry standards acceptable to ESA; or • Meets distributor specifications approved by a P. Eng., competent person, and no undue hazard; or	Major equipment is approved under the Rules of the Distributor. Certified test reports and equipment standards are accessible on the USF website. An engineer approved this distribution equipment. Equipment approval sheets show the applicable standards, technical information, manufacturer, vendor, and stock number.		X		

	• Documented approval process • Supporting documentation of approvals • Certified tests reviewed by a competent person • Composite poles & wood poles	Observations: • No new major equipment was approved during the audit period.				
6(1)(b)	Re-Use of Major Equipment • Documented process identifies competent person • Used major equipment approved by competent person or a P. Eng. and no undue hazard. • Competent person records no undue hazard • Testing or repair – competent person records no undue hazard • Must fail safely	Approval of re-used equipment procedures is documented and approved by the President and CEO. Only transformers from the field are re-used. Transformers from the field are inspected by a competent person. If the transformer is in good condition, the competent person will sign off with a “no undue hazard' statement and re-stock. Observations. • Re-used equipment approval process is documented • No major equipment reused		X		
6(1)(b)	Non-major Equipment approval under Rule of the Distributor (no undue hazards**):** • Documented approval process • Meets industry standards; or • Distributor developed specifications; or • Good utility practice – 2 years or more, documented confirmation by a competent person, no undue hazards • GUP may include successful use by a different LDC	Non-major equipment is selected from the USF's equipment list. Observations • No new non-major equipment was approved during the audit period. • Equipment approval sheets are available on USF		X		

6(1)(b)	Equipment is specified to meet Rule of Distributor standards • Tendering • Purchasing alliances • Purchasing approved equipment (Purchase orders, reference to standard by model numbers, engineering specifications, technical data)	Equipment is specified by LUI/USF part number, equipment description, applicable standards, technical description, manufacturer, and ratings. Observations: Reviewed Cam Tran PO and test data from the manufacturer • PO # 02535 • PO # 02615 • PO # 02551 • PO # 02616		X		
6(1)(b)	Supplied equipment meets Rule of Distributor requirements • Inspection procedure • Dealing with vendor non-compliances	Equipment is checked against packing slips and purchase orders to ensure accuracy and satisfactory condition to confirm shipment. • no poles were ordered, • Stella Jones, the only supplier		X		
6(2)	Inspection and testing of equipment supplied based on Rule of Distributor requirements (Inspection and testing records)	LUI has not developed any unique standards. It relies on existing industry standards. (USF);	X			
6(2)	Determining inspection and testing methods for equipment supplied to distributor (Records of analysis, conclusions , manufacturers declaration, witness testing, third party or distributor testing)	LUI has not developed any unique inspection or testing methods.	X			
6(1)(a) 6(2)	Dealing with vendor noncompliance (Field evaluation, rejection, communications)	Non-conforming equipment that is shipped is quarantined, vendors are contacted, and the equipment is returned.		X		
7	Plans: • Prepared by a P. Eng.; and/or	LUI is a member of USF. USF's standard design drawings are certified by a group of professional engineers.		X		

	• Based on standard design drawings and specifications or Sect. 75 OESC • Reviewed and approved by a P. Eng. or ESA • Plans by subdivision developers • Plans by external consultants • Temporary power design standard • Deviation from approved standards	• The standard designs are displayed on the plans. • For non USF use outside engineering company, • HyGrid solutions. • All the subdivision plans are prepared by the developers' consultant, reviewed by HyGrid, and approved by the Manager, Asset Management.				
7	Approved plans or standard designs required except for: • Like-for-like construction • Emergency work • Legacy construction	Standard design drawings, work instructions, and specifications are provided, except for like-for-like, emergency and legacy work are prepared by a competent person and approved by the Manager, Asset Management. Observations: Reviewed the following: • EC2024-007 o Hy-Grid design o 44kV & 4kV o Pole replacement due to woodpecker damage • EC2024-109 • 3 phase pad mount • LUI design, USF • LUI owns the primary and TX • EC2021-028 o New 27kV pole line for industrial/commercial o HyGrid design • EC2023-400 o Riser pole to subdivision o To East Fields subdivision o HyGrid design		X		

		• EC2023-401 o Rebuild to feed East Field subdivision o 4kV supply, dual rated TX o HyGrid design All the above plans display: approved standard design drawings, certificate of approval, and P. Eng. seal.				
7	Ensure third party attachments are: • Authorized; and • No adverse effect on distribution system safety • Engineering plans certified by LDC or third-party P. Eng. (no gaps in certification) • Certified third party standards – evidence of certification • Third party generation • Bell Canada standards	Third party attachers are Cogeco Cable, Bell Canada, ExploreNet, and Cobourg Network Inc. • On receipt of a third-party application LUI directs the third party to LUI's consulting engineer. • The third party surveys the subject lines. LUI's consultant prepares, certifies, and seals the third-party plans. • The plans are reviewed and approved by Manager, Asset Management, during the audit period. • LUI provides the required make-ready work. Observation: There was one third party attachment application for Bell during the audit year. The attachment application was reviewed and was acceptable.		X		
7	Up-to-date copies of internal specifications and identified standards available to approving P. Eng. – examples: • Ontario Electrical Safety Code • CSA Std. O/H C22.3 No. 1 • CSA Std. U/G C22.3 No. 7 - • Substation CAN/CSA 22.3 C61936-1	LUI's staff has hard copies and electronic access to necessary codes, standards, and equipment standards. USF standards are available electronically and binder **C22.3 No. 11 (Maintenance)** • LUI will be reviewing Internal documents and determine what if any changes are required. LUI will be collaborating with other distributors.		X		

	• Equipment Standards					
7	Ensure P. Eng. memberships valid and current	LUI does not employ P. Eng. Use External P.Eng as needed	X			
7	Identify competencies of identified competent persons and ensure they have the required competencies (training records, position descriptions, resumes)	Qualification of identified competent staff reviewed and confirmed. • Reviewed CVP		X		
7(1)(a)	Installations based on plans by a P. Eng.: • Reviewed and approved by a P. Eng.; or • Reviewed and Approved by ESA (Sample of plans)	Installations are based on standard design drawings reviewed and approved by P. Eng. • Based on USF		X		
7(1)(b)	Installations based on standard drawings and specifications assembled by a P. Eng., engineering technologist or competent person (Sample of drawings and specifications)	Installations are based on standard drawings and specifications assembled by competent persons and approved by Manager, Asset Management.		X		
7(2)(a) 7(2)(b)	Plans, standard design drawings and specifications reviewed and approved by a P. Eng. or ESA (Signatures, stamps)	Plans and standard design drawings and specifications certified by consulting engineers and approved by Manager, Asset Management.		X		
7(3) 7(5)	Plans, standard design drawings and specifications certified by a P. Eng. or ESA (Plans, drawings, specifications, certificates)	USF's standard design drawings are approved by P. Eng.		X		
7(6)	Ensure that standard design drawings, specifications and certificates are: • Recorded and tracked • As-built drawings show changes made in construction	Plans and standard design drawings are scanned stored electronically and indexed by year, and job #. Project files contain the following: • Estimates • Material List		X		

	• Retained and available to ESA • Retained for minimum of one year after audit • Electronic storage	• Correspondence • Offer to Connect • GIS Records • MCR				
		• Reviewed Admin practices o Privacy Policies and procedures				
8(1)	Construction verification program: • Approved by ESA • When approved • Qualified persons list up to date • Any changes approved	Revised CVP dated April 15, 2020 Approved by ESA. CVP training every year CVP refresher training to staff on **February 25, 2025**. Qualified persons' list is maintained up to date. Observations; • Records of training available and reviewed		X		

8(1)	Except for like-for-like replacements, emergency and legacy work, installations based on:
	• Approved and certified plans before construction; or
	• Standard design drawings and specifications
	• Approved equipment
	• Safety standards met
	• Non-compliances noted in record of inspection
	• Collections Department
		Approved plans & standard design drawings and equipment is provided for construction except for like-for-like, emergency and legacy work. The installations are based on approved and certified plans or standard design drawings and specifications before construction. Any non-compliances are resolved and recorded.
		
		Reviewed the following:
		• EC2023-400
		  o Eastfield subdivision ,
		  o Trench and road crossing
		  o External consultant design
		  o
		    ▪ EC2024-007
				X		

		o Hy-Grid design o 44kV & 4kV o Pole replacement due to woodpecker damage o • EC2024-109 • pad mount • LUI design, USF • LUI owns the primary and TX • • EC2021-028 o New 27kV pole line for industrial/commercial o Dodge street o HyGrid design Observations: • Approved construction drawings and work instructions are provided. Sub-division underground installation is inspected (partial/final and certificate) by LUI competent staff. Partial and final certificates • Record of inspections and Certificates are signed off by LUI staff.				
8(1)	Ensure construction inspected and approved before use: • When implemented? • Monitored to cover all construction	All construction is inspected and approved before use.		X		
8(1)	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person • Metering	Like-for-like, emergency and legacy work inspected and confirmed safe by competent person: Reviewed the following Trouble calls		X		

	• Cutoff and reconnection • Customer Service • NC's rectified • No undue hazard statements • Inspection record and certificate	• HV fuse blown o Animal contact o Replaced fuse Observations: All the above-mentioned works were signed off by a competent person with no undue hazard statement. Records available for review.				
8(2)(a) 8(2)(b) 8(2)(c)	Inspection by: • P. Eng.; or • Qualified person identified in inspection verification program; or ESA	Inspections are carried out by competent persons identified in the CVP.		X		
8(3)	Records of inspection include: • Inspection before use of installation • Approved plan or standard design followed • Approved equipment used • Inspection date • Installation identified • Non-compliances rectified • Stamped, signed, or initialed • Inspection verification program followed	Records of inspection include: • Marked-up and as-built plans • Record of inspection • Approved equipment used • Inspection date • Installation identified • Non-compliances were not noted • Stamped, signed, or initialed by the competent person • Inspection verification program followed.		X		
8(4)	Safety standards met before certification Certificates available and show: • Identify work inspected • Safety standards met • Date of certification • Stamp, signature, or initials	Certificate of inspection provides all necessary information on what was inspected, identify the inspector, date of inspection, stamp and initial of the inspector		X		

	• Like-for-like and legacy construction no undue hazards					
8(7)	Certificates and records of inspection available to ESA and: • Records and certificates of inspection • Covers all applicable construction • Signed and dated • Records of inspection for underground work	Certificates and records of inspections are available in engineering project files.		X		
	Third party contractors trained and listed in the CVP	No third-party contractors are trained and listed in the CVP. Third-party attachers process is documented in the CVP dated April 15, 2020.		X		
	Sampling program developed	No inspection sampling was done.	X			
	Process for resolving non-compliances and design changes	Non-compliances and field proposals for design changes are discussed with engineering. If agreed to, plans are marked up and re-drafted into as-built plan		X		
	Third-party construction by contractors • Construction and maintenance on electrical distribution system • Records of inspection and certificates • Approved plan followed	Third party construction of subdivision work by the developer's contractor and substation work by LUI approved contractor is inspected by LUI's competent person as per CVP.		X		
	Third-party attachment – communications and community antenna systems: • Meets safety requirements • Non-compliances and variations resolved • Inspection by P. Eng. or person qualified in CVP • Certificate and record of inspection	Third party attachment inspections are performed by LUI's consulting engineer and approved by LUI's competent person. • RE2024-405 o Bell o Durham St. N, Colborne o 3 pole o/h		X		

	• Other joint use	Plans were prepared by P. Eng. (NBM) reviewed by Hi-Grid and display certificate of approval and P.Eng. seal .				
		Safety survey				
		LUI's Public Safety Promotions are as follows: • Public Safety information on LUI's web site. • Customer Satisfaction Survey by Red Head • Holiday Safety messages on radio. All seasons are • Social media (Facebook, Mobile App and Twitter) to convey safety messages, scheduled and un-scheduled and the duration. • Outage map and planned work on web to inform customers • Billing inserts on electrical safety tips. • Safety presentations to schools (6 sessions) •		X		
	Public safety promotion Regular training includes safety Performance assessment includes safety Records on dealing with safety issues Training materials Interest and input from the Board	• Safety training/orientation for new contractors. • Health and Safety Policies posted on the intranet. And binders available, new staff go through 2-3 days of safety training • Safety meetings for the line staff (held outside) • Lost Time Incident "LTI" - 21,346 • No lost time injury • LUI Emergency Plan – Fire Department, Police, EMS, the Town, and Union Gas.. The group meets once a year • Member of South-Central Ontario LDC Mutual Assistance Plan. 17 LDC Members of the Mutual		X		

		Assistance Plans have agreed to participate on how these utilities would provide support to each other in various areas, e.g., emergency assistance, engineering support, material procurement support, fleet support, and communication support. • Health & Safety report presented to the Board quarterly. • Business Continuity Plan, being developed with IT.				

RAVEN ENGINEERING INC.

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Load Forecast Study

Prepared for

Lakefront Utilities Inc.

Rev 0

Revisions		
No.	Date	Description
A	2025-09-19	Issued for client review
B	2025-09-25	Issued for client review
C	2025-10-28	Addressed client review comments
0	2025-11-18	Issued Final

Prepared by

Kenechukwu Adibe, EIT

Reviewed by

Andrew Durward, P.Eng.

Table of Contents

Appendices

1.0 Executive Summary

The Load Forecast has been updated with 2025 summer peak loads and a review of projected developments.

The 44kV system in Cobourg has sufficient capacity to supply forecast loads over the study period, providing the Port Hope M17 feeder is used during peak load periods. Consideration should be given to re-conductoring the 44kV M2 with 556 ASC to increase feeder capacity.

The 27.6kV system in Cobourg has sufficient capacity to supply forecast loads over the study period. Additional analysis is required to determine the timing of new 27.6kV feeders.

There are capital plans to convert the remaining 4.16kV system in Cobourg to 27.6kV supply.

The 44kV and 4.16kV systems in Colborne have sufficient capacity to supply forecast loads over the study period.

Consideration should be given to implementing a third feeder at Durham MS, and/or upgrading the feeder exit cables to provide adequate capacity towards the end of the study period.

2.0 Historical Load

Historical load data was obtained from the Utilismart Revenue Metering database.

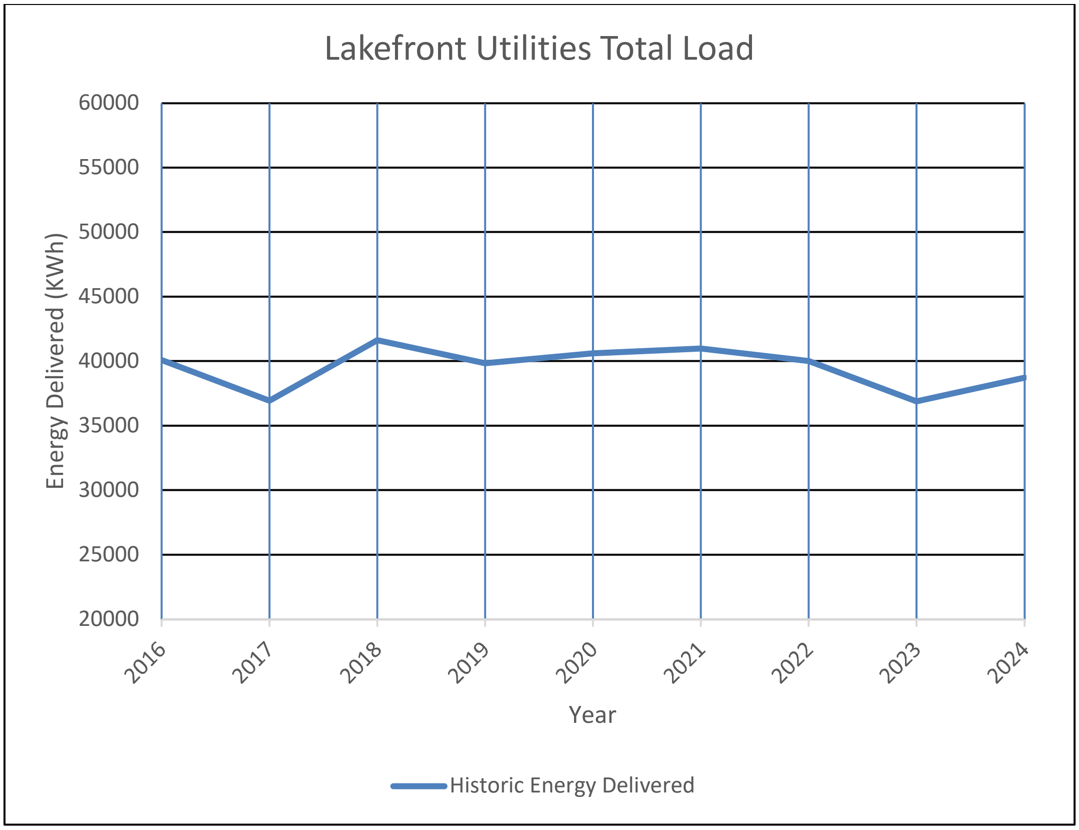
Cobourg 2025 peak load of 41.995 MW occurred on August 12 at 16:30.

Colborne 2025 peak load of 3.815 MW occurred on July 30 at 17:00.

Lakefront is a summer peaking utility with peak annual loads occurring in the summer.

2.1. Lakefront Utilities Total Load

Total historical energy delivered for the utility is shown in Graph 1.



Graph 1: Lakefront Utilities Total Load

The graph shows that load remained relatively stable since 2016.

2.2. Town of Cobourg

The Town of Cobourg load is supplied by Port Hope TS feeders M2 and M4. These feeders are dedicated to Lakefront Utilities. The summer historic demand for the Town of Cobourg is shown in Table 1. These values reflect normal conditions with no load transfers.

	Summer				
	Historical Peak Demand (MW)				
Year	**2021**	**2022**	**2023**	**2024**	**2025**
Date/Time of Peak	2021-08-26	2022-07-20	2023-09-06	2024-08-27	2025-08-12
	15:45:00	16:10:00	16:25:00	16:15:00	16:30:00
Port Hope M2+M4	41.577	41.003	36.205	39.232	41.995

Table 1 – Town of Cobourg Historic Load

2.3. Town of Colborne

The Town of Colborne is supplied by Port Hope TS Feeder 50M16 via Colborne MS#1 and Colborne MS#2. This feeder is shared with Hydro One. The summer historic demand for the Town of Colborne is shown in Table 2. These values reflect normal conditions with no load transfers.

	Summer				
	Historical Peak Demand (MW)				
Year	**2021**	**2022**	**2023**	**2024**	**2025**
Date/Time of Peak	2021-08-26	2022-08-08	2023-09-06	2024-08-01	2025-07-30
	16:15:00	17:30:00	19:00:00	16:45:00	17:00:00
Feeder 50M16 Colborne MS#1 + MS#2	3.660	3.658	3.717	3.795	3.815

Table 2 – Town of Colborne Historic Load

2.4. Explanation of Historic Peaks

The historic peaks for both the Town of Cobourg and the Town of Colborne occurred under normal operating conditions with no abnormal conditions or load transfers.

- Town of Cobourg – Normal condition, no load transfers.
- Town of Colborne – Normal condition, no load transfers.

2.5. LUI's Load in Study Area as a Percentage of Total Electrical Load

100% of LUI's load is located within the Study Area.

2.6. Market Rate Segmentation

Market and rate segmentation of current electrical load is shown in Table 3.

There are no forecast changes in segmentation for the customer loads.

	Residential	Commercial	Industrial	Agriculture	Total
PORTHOPE TS (MW)	88%	12%	1%	0	------

Table 3 – Market Rate Segmentation

3.0 Load Forecast

3.1. Methodology

The load forecast methodology used a combination of extending historic trends and consideration of proposed new developments.

3.2. Town of Cobourg

Development growth in the Town of Cobourg has traditionally been relatively low. Major industrial loads have decreased and have been replaced with residential development.

A number of subdivision developments are proposed and are included in the forecast. The forecast used estimated unit loads with the proposed unit quantity and timing of the development.

Several commercial developments are proposed and are included in the forecast as point loads.

The remainder of the forecast is based on an assumed annual load growth of 0.5%, based on historical averages.

3.3. Town of Colborne

Development growth in the Town of Cobourg consists of minor residential development.

The forecast is based on an assumed annual load growth of 0.5%.

4.0 Load Growth Plans

Maps showing proposed development areas are included in Appendix A.

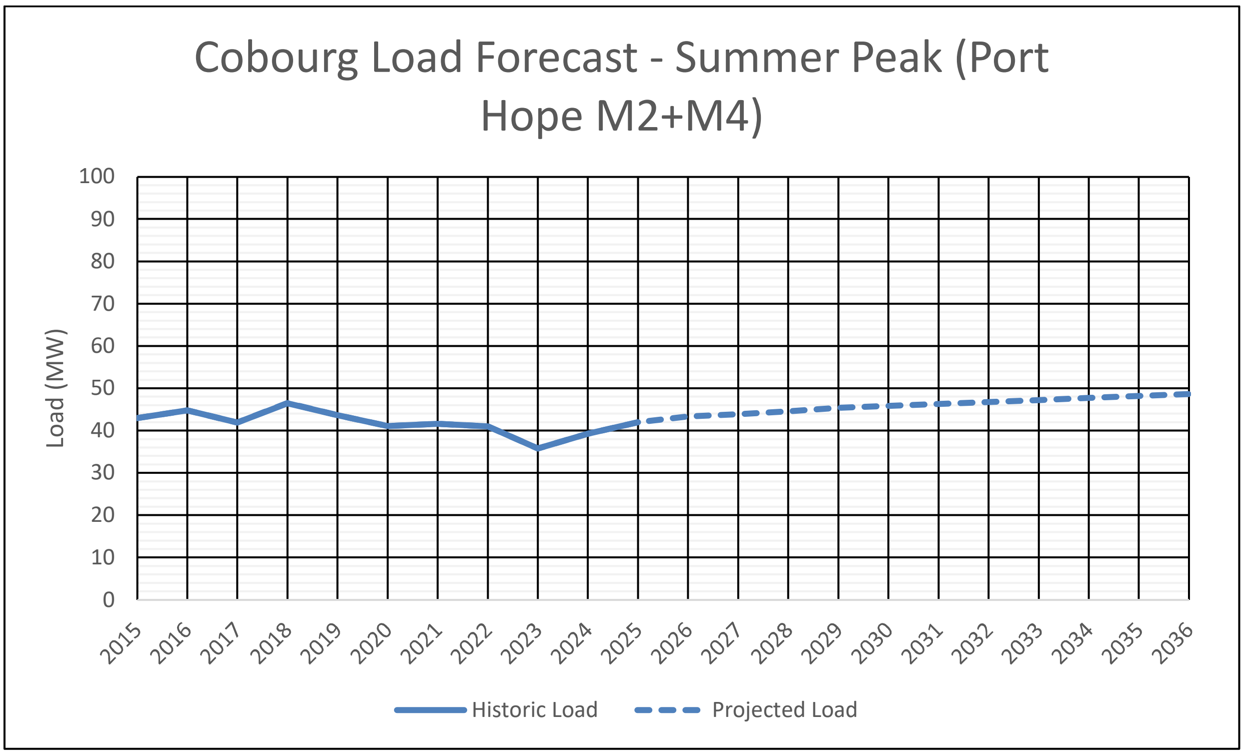
5.0 Load Forecast - Detailed Breakdown

5.1. Town of Cobourg

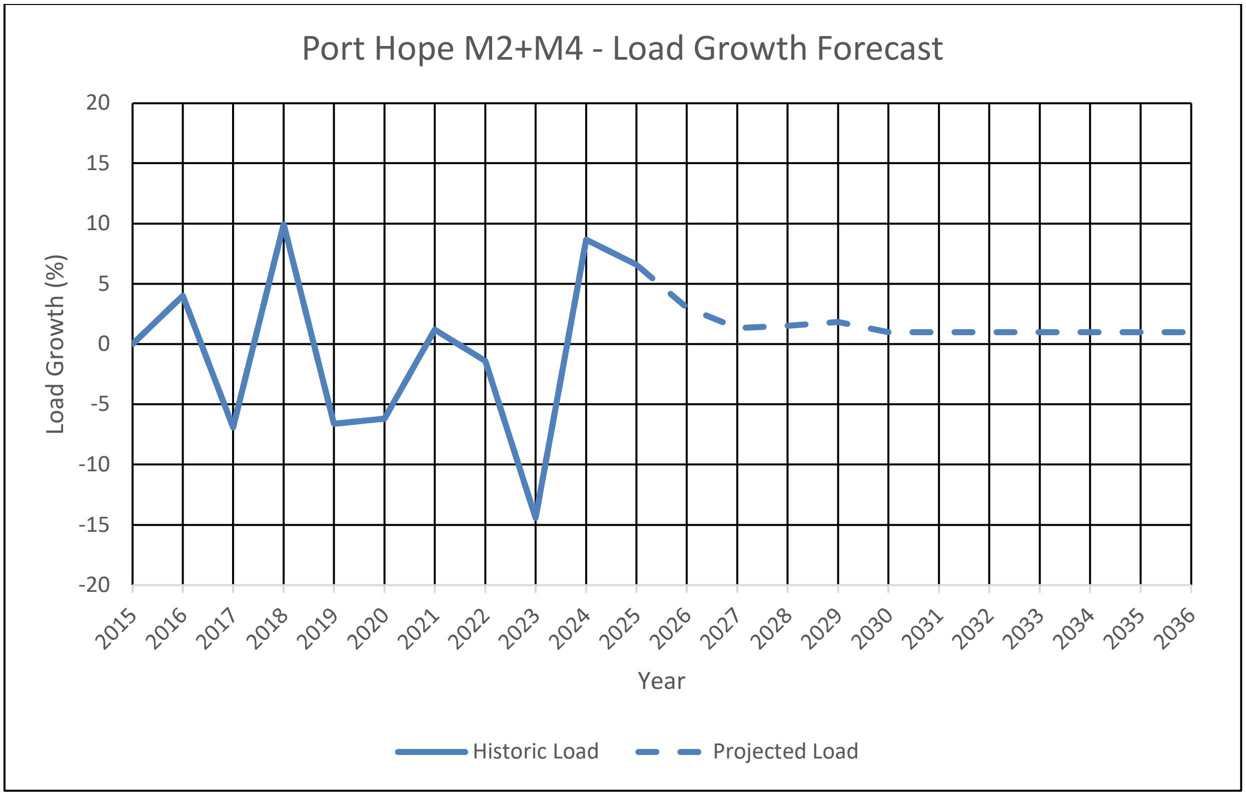
As explained in Section 3.2, load forecast for Cobourg includes a combination of planned developments and assumed annual load growth.

Town of Cobourg Port Hope TS Feeders M2+M4								
Year		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Forecasted Load Growth (MW)	**Industrial**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Commercial	0.0	0.624	0.0	0.0	0.208	0.0	0.0
	Residential	0.0	0.264	0.145	0.235	0.174	0.0	0.0
	Peak Total	**41.995**	**43.303**	**43.881**	**44.555**	**45.383**	**45.837**	**46.295**

Table 4 – Town of Cobourg Load Forecast Breakdown



Graph 2:Town of Cobourg - Load Forecast



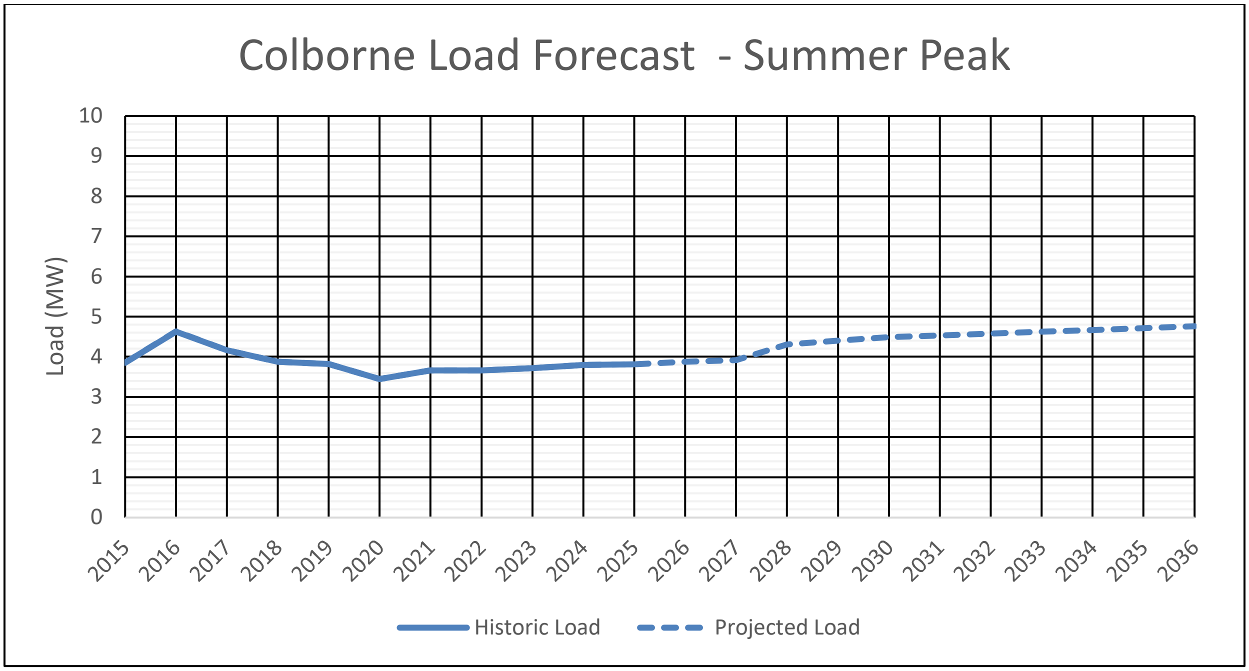
Graph 3:Town of Cobourg – Load Growth Forecast

5.2. Town of Colborne

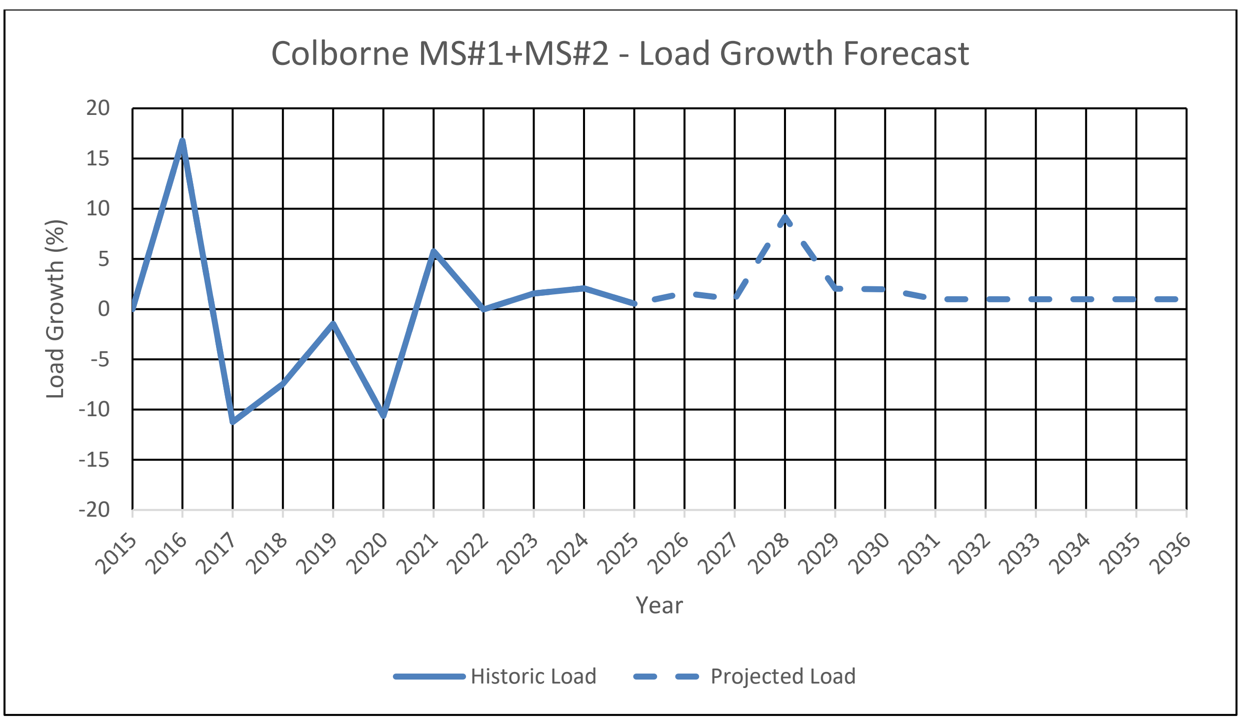
As explained in Section 3.3, load forecast for Colborne includes an assumed annual load growth.

Town of Colborne Colborne MS#1 + #2								
Year		**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
Forecasted Load Growth (MW)	**Industrial**	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Commercial	0.0	0.0	0.0	0.312	0.0	0.0	0.0
	Residential	0.0	0.023	0.0	0.044	0.046	0.044	0.0
	Peak Total	**3.815**	**3.876**	**3.915**	**4.309**	**4.398**	**4.486**	**4.530**

Table 5 – Town of Colborne Load forecast Breakdown



Graph 4: Town of Colborne - Load Forecast



Graph 5: Town of Colborne - Load Growth Forecast

6.0 System Capacity - Cobourg

6.1. 44kV System

The 44kV system in Cobourg is supplied by the HONI Port Hope TS M2 and M4 feeders. There is a backup supply from the Port Hope M17 feeder which is used at the discretion of Hydro One during contingency situations.

A planning capacity of 400 amps, or 30.5 MW is assumed. Actual feeder capacity is higher than the planning capacity, which provides contingency for emergency operations.

Operating capacity is based on 80% of the summer overhead conductor ratings[1] and is tabulated below.

Feeder	**M2**	**M4**
Main conductor	336 AAC	556 AAC
Conductor Ampacity	565 Amps 43.1 MVA	775 Amps 59.1 MVA
Operating Capacity (80%)	452 Amps 34.4 MVA	620 Amps 47.2 MVA

Table 6 – Cobourg 44kV Feeder Capacity

To confirm adequate feeder capacity we will consider loss of one element, either M2 or M4.

Loss of M2 means all load will be supplied by M4. The M4 loading under this contingency will exceed the planning capacity in 2025. The loading will be within the operating capacity for the duration of the study period.

Loss of M4 means all load will be supplied by M2. The M2 loading under this contingency will exceed both the planning and operating capacity in 2025 and will exceed the conductor capacity in 2026.

Additional 44kV supply is available from the Port Hope TS M17 feeder during contingency conditions.

Consideration should be given to re-conductoring the M2 with 556 ASC to increase feeder capacity.

6.2. 27.6kV System

The 27.6kV system is supplied by three Lakefront owned substations in the Town of Cobourg.

[1] Hydro One Overhead Distribution Standards, Table 3.

Station capacity for MS28-1 and MS28-2 were determined in a study completed in 2020[2].

The MS28-2 primary cables were replaced since 2020, increasing the capacity of that station to 32 MVA.

Station	Capacity
MS28-1 Victoria	26.6 MVA
MS28-2 Brook Rd	32.0 MVA
MS28-3 Ontario	33.3 MVA

Table 7 – Cobourg 27.6kV Station Capacity

The 27.6 kV loads are internal to Lakefront's distribution system and there is no revenue meter data available to confirm loads. Historical loads have been retrieved from the SCADA system.

SCADA historical loads shows that the 27.6 kV system reached a peak load of 27.57 MW at 16:30 on August 12th, 2025. (Note: MS28-2 peak load was estimated at approximately 9.5 MW. MS28-2 SCADA is offline due to communications failure.) 27.6 kV system load will increase by 4.5 MW as voltage conversion is completed, bringing the future total to 32.07 MW.

With one station out of service, the load can be supplied by the remaining two stations.

Each station currently has two (2) active feeders for a total of six (6). MS28-2 has an idle F5 position and MS28-3 has an idle F8 position.

There is sufficient capacity in the 27.6 kV system to supply forecast loads over the study period. Additional analysis is required to determine the timing of bringing the idle feeders online.

6.3. 4.16kV System

Historical SCADA loads show that the 4.16kV system reached a peak load of 4.5 MW at 16:30 on August 12th, 2025. The 4.16kV load is expected to decrease in the future as it is converted to 27.6kV operation between 2026 and 2031. The 27.6kV load will increase accordingly over the same period.

7.0 System Capacity – Colborne

7.1. 44kV System

Colborne load is supplied by the Port Hope M16 feeder Lakefront does not own any 44kV distribution in Colborne, all 44kV distribution is owned by Hydro One.

---

[2] 203110 Station Capacity Study, Lakefront Utilities, Raven Engineering, 2020-12-15.

7.2. 4.16kV System

Colborne load is supplied by two Lakefront owned substations.

Station	Capacity
Victoria MS	6.7 MVA
Durham MS	5.5 MVA

Table 8 – Colborne 4.16kV Station Capacity

Victoria MS has three (3) 4.16kV feeders with an exit cable capacity of 566 amps.

Durham MS has two (2) 4.16kV feeders with an exit cable capacity of 381 amps.

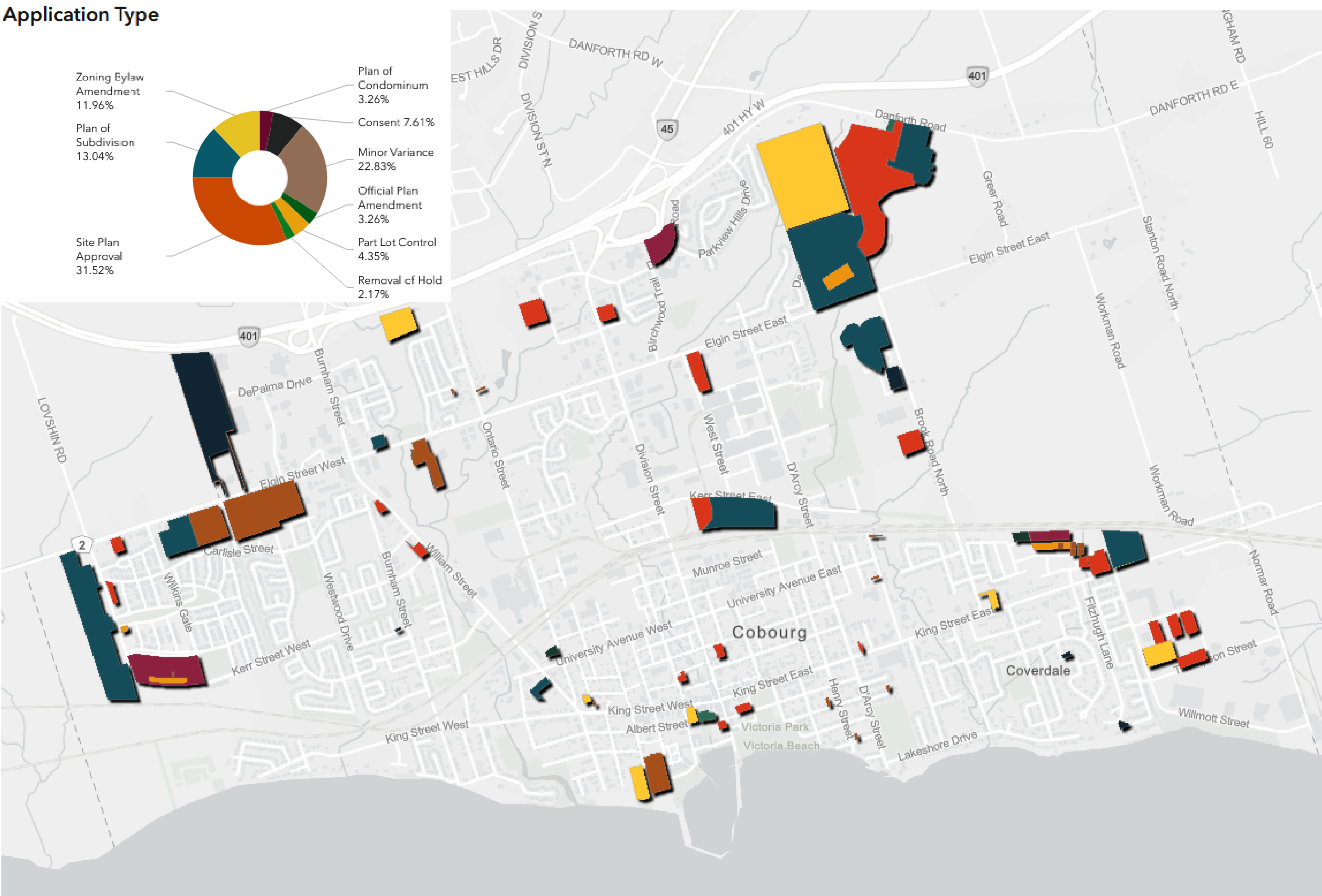
Durham MS capacity is limited by the combined rating of the two feeders.

With one station out of service, the remaining station can supply forecast loads over the study period. The Durham MS feeders reach 80% of their cable capacity towards the end of the study, assuming the load is equally balanced between them.

Consideration should be given to implementing a third feeder at Durham MS, and/or upgrading the feeder exit cables to provide adequate capacity towards the end of the study period.

8.0 Town of Cobourg – Projected Developments

See attached development map.



Cobourg Development Map - 2025
(source - Town of Cobourg Development Dashboard)

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Generation Capacity Study

Prepared for

Lakefront Utilities

September 2025

253109

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1.0 Summary

This report provides generator connection capacity limits on the Lakefront Utilities distribution system in accordance with Ontario Energy Board requirements.

2.0 Background

OEB requires that the Utility publish the available capacity for connecting generator on each feeder in their distribution system.

Lakefront Utilities Service Inc. (LUSI) operates 44kV, 27.6kV and 4.16kV distribution systems in the Town of Cobourg and a 4.16kV distribution system in the Town of Colborne.

All are supplied by 44kV feeders from Hydro One Port Hope TS.

3.0 Capacity for Generation Connections

The capacity for generation connections needs to be addressed at various levels in the system including transmission, transformer station, distribution feeders and sub-feeders.

The limits on generation connections are based on equipment thermal rating, system short circuit ratings and power quality impacts on Lakefront Utilities Service Inc. customers.

3.1. Transmission Capacity

Lakefronts Utilities service Inc is supplied by Hydro One 115kV circuit Port Hope Q50.

There are no restrictions on these transmission circuits that would impact distribution connected generations.

3.2. Feeder Capacity – Cobourg

Cobourg feeders operate at 44kV, 27.6kV and 4.16kV. The planning ampacity of 27.6kV and 44kV feeders is 400 amps, and the planning capacity of 4.16kV feeders is 200 amps.

The feeders have the following limits on connecting generation:

- The maximum size of a DER connection shall not exceed 5 MW on 27.6kV and 44kV feeders, and 1 MW on 4.16kV feeders.
- The total acceptable generation on a 44 kV feeder is 30 MW
- The total acceptable generation on a 27.6kV feeder is 19 MW
- The total acceptable generation on a 4.16kV feeder is 1.45 MW

The feeder generation capacities listed below are based on the above criteria and the existing generation connections.

Town of Cobourg					
Station	**Feeder**	**Voltage (L-L) kV**	**Generation Capacity (MW) (A)**	**Connected Generation (MW) (B)**	**Available Capacity (MW) (A)-(B)**
Port Hope TS	M2	44	30	3.02	26.98
Port Hope TS	M4	44	30	0.6	29.4
Victoria MS28-1	F1	27.6	19	0.2	18.8
Victoria MS28-1	F2	27.6	19	0.9	18.1
Brook Rd MS28-3	F4	27.6	19	1.3	17.7
Brook Rd MS28-3	F5	27.6	19	0	19.0
Brook Rd MS28-3	F6	27.6	19	0.5	18.5
Victoria MS28-3	F7	27.6	19	0	19.0
D'Arcy MS	F10	4.16	1.45	0	1.45
Orr MS	F13	4.16	1.45	0	1.45
Orr MS	F14	4.16	1.45	0	1.45
Kerr MS	F19	4.16	1.45	0	1.45

3.3. Feeder Capacity – Colborne

Colborne feeders operate at 4.16kV. the planning capacity of 4.16kV feeders is 200 amps.

The feeders have the following limits on connecting generation:

- The maximum size of a DER connection shall not exceed 1 MW on 4.16kV feeders.
- The total acceptable generation on a 4.16kV feeder is 1.45 MW

The feeder generation capacities listed below are based on the above criteria and the existing generation connection.

Town of Colborne					
Station	**Feeder**	**Voltage (L-L) kV**	**Generation Capacity (MW) (A)**	**Connected Generation (MW) (B)**	**Available Capacity (MW) (A)-(B)**
Victoria MS	F1	4.16	1.45	0	1.45
Victoria MS	F2	4.16	1.45	0.3	1.15
Victoria MS	F3	4.16	1.45	0	1.45
Durham MS	F4	4.16	1.45	0	1.45
Durham MS	F5	4.16	1.45	0	1.45

Appendix A: **List of Connected Generation > 10W**

Station	Feeder	Customer	Connected Generation (MW)
Victoria MS28-1	F1	1125 Elgin St. W.	0.2
Victoria MS28-1	F2	206 Furnace St.	0.4
		232 Spencer St.	0.07
		840 Division	0.25
		LUI Service Center	0.1
		Cobourg Water Treatment Plant	0.05
Brook Rd MS28-3	F4	Mason Windows	0.5
		750 Darcy St.	0.5
		83 Veronica St.	0.2
		Venture 13	0.1
Brook Rd MS28-3	F6	675 Brook Rd. N	0.036
		210 Wilmott St.	0.5
Victoria MS	F2	Keeler Centre, Colborne	0.25

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Distribution Automation Strategy

Prepared for

Lakefront Utilities

Rev 0

253107

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RAVEN ENGINEERING INC.

Table of Contents

1.0 Executive Summary

Lakefront Utilities is planning to invest in Distribution Automation over the next several years. This report identifies the opportunities for automation and provides a strategy and high-level budget to implement them.

Implementing FLISR (Fault Location, Isolation, Switching and Restoration) licensing on the existing Survalent SCADA system would provide Lakefront with a flexible system that allows integration with existing substations, existing and new pole and pad-mounted equipment while maintaining the ability to purchase high voltage hardware from multiple vendors.

Under the recommended plan, 44kV and 27.6kV feeders would be divided into two equal sections with normally closed reclosers or motor-operated switches. Additional devices would be installed as normally open switching points between feeders. These devices along with existing station circuit breakers would be operated by FLISR to reduce the number of customers affected by a permanent outage by a factor of 2 and improving SAIDI and SAIFI by a factor of 2.

The estimated budget for implementation is $2Million, not including contingency.

2.0 Distribution Automation

Distribution Automation (DA) is a common term that encompasses a wide range of equipment, hardware, communications systems and software. In this report, the term automation refers to ***automatic operation*** of high voltage switches, circuit breakers and reclosers in response to measured inputs. It does not include manual operation of equipment by utility personnel. A DA system will complete the switching without manual intervention and provide alarms or status updates to the utility informing them of what has already happened.

2.1. Reliability

The purpose of DA is to improve reliability of supply to customers.

The reliability of supply is primarily measured and quantified by internationally accepted indices and are defined in the OEB's Electricity Reporting & Record Keeping Requirements.:

- **SAIDI** - The length of outage customers experience in the year on average expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. An interruption is considered sustained if it lasts for at least one minute.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

- **SAIFI** - The number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

- **CAIDI** - The average interruption time per customer affected and can be found by dividing the SAIDI value for the given year by the SAIFI value.

$$CAIDI = \frac{SAIDI}{SAIFI}$$

2.2. DA Requirements

DA requires several things to be in place, including:

- HV switching devices,
- Sensing devices,
- Communications,
- A decision-making System,
- An algorithm or decision-making process

3.0 Distribution Automation Equipment

3.1. HV Switching Devices

High voltage switching devices are required to open and close distribution circuits to isolate system faults and restore power to customers. These devices require the following attributes:

- Voltage rating for the application
- Current rating for the application. Can be either load break or fault interrupting.
- Secure power supply for independent operation during power outages

Available automated switching devices include circuit breakers, line reclosers, pad-mount switches and motorized pole mounted load break switches.

3.1.1. Circuit Breakers

Circuit breakers located at substations are rated for fault interrupting and can be used for fault isolating and load switching. They are equipped with PTs and CTs supplying protection relay. The breakers and relays require secure DC power battery systems ensuring reliable operation during power outages.

3.1.2. Line Reclosers

Reclosers typically have a lower fault interrupting rating than circuit breakers but are often adequate for use on utility distribution systems. Fault levels on Lakefront’s 27.6kV system are low enough that reclosers can be used as feeder breakers at their substations. Some reclosers can operate each phase pole independently instead of 3 phase operation. This is useful for specific applications such as single-phase distribution in rural areas.

Reclosers can be pole mounted for overhead applications or pad mounted for underground applications. The switching equipment is essentially the same.

Reclosers have the benefit of providing protection of the downstream circuit. This can be used to coordinate tripping to minimize the number of customers affected by a fault. The controller relays have the capability of multiple setting groups which allow different overcurrent settings or reclosing logic for different feeder configurations. Changing between setting groups can be performed automatically based on inputs to the relay or from communications.

Reclosers with adjustable settings can be used to ensure that feeders are adequately protected during alternate configurations.

3.2. S&C IntelliRupter

This device is a recloser with the added functionality of pulse closing technology. Conventional reclosers detect a permanent fault by reclosing onto the fault until the reclose sequence runs to lockout. This means the faulted equipment is re-energized a number of times, causing additional damage and potentially increasing risk to the public. The IntelliRupter tests the line with two short closing pulses of 5 msec duration and measures the resulting current to determine if the line is faulted or clear. If the line is faulted it remains open and initiates an alarm. If the line is clear it recloses to restore power.

IntelliRupter is available in pole mounted or pad mounted configurations.

IntelliRupter will soon be available with an SEL-651RD advanced controller for additional functions.

3.2.1. Line Switches

Motor-operated load break disconnect switches are typically rated for interrupting load up to 600 amps but are not rated for interrupting faults currents.

S&C SCADA-Mate switches are common in the utility industry. The switches are equipped with S&C 6800 controllers that monitor voltage and current and provide local and remote control. The controllers do not have protection functions, but they can detect fault current which can be used in automation applications.

3.2.2. Pad Mount Switches

Pad mount switches usually include multiple switching ways in various configurations. Switch ways can include load break switches or fault interrupters with SEL overcurrent relays.

Options include visible break switches and grounding switches. While these options don't affect the ability of the switch to be used for DA, they should be considered so that they integrate with utility operations.

3.3. Sensing Devices (IEDs)

Sensing devices for DA include protection relays and switch controllers and are commonly referred to as Intelligent Electronic Devices (IEDs). They measure system voltage, current and frequency as well as local device status and provide that information to the decision-making process. They can open and close switching devices based on internal programming or signals received from other systems.

Protection relays are used to detect system faults and trip circuit breakers or reclosers. They are equipped with communications ports and protocols to integrate with other devices or systems and have internal logic capabilities for customized applications. They can provide real time information of their monitored and measured values.

Switch controllers are used to open and close motor-operated switches in response to manual or remote signals. Some can also monitor voltage and current and provide that real time information to other systems.

3.4. Communications Systems

Secure and reliable communications is required between IEDs and decision-making systems for DA to function. Communications can be IED to IED, or IED to a decision-making system such as a SCADA system.

Typical DA communication systems include:

- fiber-optic,
- radio, and
- cellular.

Leased telephone line is an older analog technology that is being phased out by Bell Canada and equipment suppliers.

3.5. Decision Making Systems

Decision making for DA can either be done in a single master system or distributed across IEDs. There are benefits and disadvantages to both approaches.

Master systems typically reside on a server located in a central indoor location, such as a SCADA system. The master has communications to all IEDs, gathers and processes information, and initiates controls to field devices through the IEDs. Decision making is programmed and performed in one location, and status of all equipment can be displayed on HMI screens. If this system fails, then all DA is affected.

Distributed decision making is done between neighbouring IEDs which share information and make local decisions on how to respond. A failed IED will only affect DA related to that point while the remainder of the system maintains functionality. Programming is distributed so initial set up and updates are done at multiple locations.

3.6. Master Algorithm

The master algorithm includes the overall logic for what the DA application is intended to accomplish and how it is going to do so. This algorithm is site and user specific but there are typical approaches to various system events.

For a loss of supply condition, the algorithm would include opening the normal supply points and closing tie switches to restore power.

For a permanent fault on a feeder, the algorithm would include determining the location of the fault, isolating the faulted section and restoring power to the remaining sections.

The master algorithm would typically be programmed for normal feeder configurations but should also be able to function during abnormal configurations caused by maintenance outages or forced outages. After a system has been reconfigured due to a permanent fault the algorithm should be ready to respond to the next event.

4.0 Existing Infrastructure

This section describes the existing infrastructure in place at Lakefront that could be used for DA implementation.

4.1. SCADA System

Lakefront has a Survalent SCADA system that monitors and controls their substations and line reclosers. It is a single seat system located in the server room at 207 Division St. and includes a workstation in Engineering.

The SCADA system polls IEDs at three 27.6kV substation, three 4.16kV substations and several pole mounted devices including reclosers, motor operated switches and primary metering units. The polled information is stored in a real time database which is accessed by the HMI package (SmartVu) and displayed on various custom programmed screens. The analog information, including bus voltages, station power and feeder amps is logged to a historical database which is accessible for creating real time graphs and for system planning.

The SCADA system includes the ability to open and close breakers, reclosers and switches, and other control functions such as blocking or enabling breaker or recloser reclosing. It is compatible with multiple communication methods, several communication protocols and field equipment from different manufacturers.

Survalent is headquartered in Ontario and is a stable company that has been in the business for over 30 years.

4.2. SCADA Communications Network

The network for SCADA communications has been built over time and includes fiber optics, cellular and radio communications. The network is cyber secure and is protected by two firewalls and secure VPN tunnels.

The existing network includes:

- Fiber optic communications to (1) site
- 900MHz radios to (8) sites
- Cellular routes to (5) sites

Most communications is Ethernet but there are still some serial connections in place.

4.2.1. Fiber Optic

Fiber optic communications connects the SCADA master at 207 Division St. to MS28-1 Victoria St. Dark fiber is leased from the utility's fiber sister company and terminated on RuggedCom switches.

The fiber is used for monitoring MS28-1, MS28-3 and communications to the 900Hz head end radio located at the Victoria St. water tower.

Initial plans included extending the fiber to MS28-2 Brook Rd. MS but that was cancelled due to the cost of building overhead fiber across the railway tracks and up Brook Rd.

4.2.2. 900MHz Radio

The SCADA system uses unlicensed 900MHz radio for communications to sites in Cobourg. The unlicensed radios are exempt from licensing due their use of frequency hopping. The radios all follow the same frequency hopping pattern to maintain synchronization.

The original radios are GE iNet-II. This product is no longer commercially available or supported. A repeater link to the 44kV M2 primary metering site has been converted to Freewave Zumlink radios. The current plan is to replace iNet radios when they fail with a current product. Replacement radios use the same power supply, antenna connection and communications cabling. Radios from different manufacturers are not compatible with one another.

The bandwidth of the radio links is limited since only one radio can communicate with the head end radio at a time. The radios predominantly use Ethernet communications, but they support serial connections. Due to the nature of their communications they are fairly immune to cyber attacks.

There is no ongoing maintenance or licensing cost for the radio system.

4.2.3. Cellular Routers

Cellular routers from Digi International are used for sites that have poor radio coverage in Cobourg, and two sites in Colborne that have no radio coverage.

The cellular routers are a rugged industrial grade product that provide ethernet and serial communications. Links back to the SCADA system use an IPsec secure VPN tunnel over the public internet. Due to the exposure to public internet, the device firmware needs to be kept up to date to ensure protection against cyber attack.

The cellular routers benefit from the carrier's infrastructure and avoid a costly build out of radio repeaters to reach distant locations.

The original routers are WR31 and are no longer commercially supported. The replacement IX30 model is a swap in replacement that uses the same power supply, antenna connection and communications cabling. Programming and VPN setup is required to complete an upgrade.

4.3. IEDs

The IEDs connected to the SCADA system include:

- Substation protection relays
- Line Recloser controllers
- Switch controllers
- Revenue meters
- Faulted Circuit Indicators

4.3.1. Substation Protection Relays

The SCADA system monitors the following substations via their protection relays:

- MS28-1 Victoria St.
- MS28-2 Brook Rd.

- MS28-3 Ontario St.
- Kerr MS
- Orr MS
- D'Arcy MS
- Victoria Colborne MS
- Durham MS

In addition to their primary fault detection function, the relays also provide breaker status, voltage, amps and power values to the SCADA system and facilitate controls to the breakers. All relays in the Lakefront system are from SEL, and they include onboard programmable logic that can be used to facilitate DA.

The SCADA system is already configured with open and close controls to the feeder circuit breakers via the relays.

4.3.2. Line Reclosers

There are two G&W Viper-ST reclosers with SEL-651R controllers in service. Another two reclosers have been removed from service and are in stores.

4.3.3. Switch Controllers

There is one S&C switch controller located on 44kV switch 5012-1. It uses serial communications to an iNet radio and is non-functional.

4.3.4. Revenue Meters

The three 44kV delivery point revenue meters (M2, M4 and M17) are monitored by SCADA to provide voltage, current and power values.

4.3.5. Faulted Circuit Indicators

There are currently two sites with SEL-FLT Faulted Circuit Indicators (FCIs), reporting back to SCADA via a common SEL-FLR node. The FLR is SCADA monitored via an iNet-II radio.

4.4. Additional Benefits

In addition to improving reliability indices, DA will also provide the following benefits:

- Reduction of lost revenue due to customer outages,
- Reduction in response time for system repairs by reducing length of line to patrol,
- Improved customer experience (less outages per customer).

5.0 Opportunities for Automation

5.1. Survalent FLISR

Survalent offers a (Fault Location, Isolation and Service Restoration (FLISR) license that could be used to implement DA while leveraging the existing asset. This requires additional licenses to the existing SCADA system and would leverage the existing SCADA system for DA without creating a duplicate system.

FLISR logic is initiated when a circuit breaker or line recloser locks out. It then:

- Uses status and alarms from field devices to determine the location of the fault,
- Isolates the faulted area,
- Restores customers upstream of the fault,
- Analyzes if adjacent feeders have enough capacity to pick up downstream loads, and
- Restores customers downstream of the isolated area.

Loss of Voltage (LOV) logic is included in FLISR. LOV logic:

- Monitors the distribution network for sudden voltage drops,
- Isolates the loss of supply area,
- Analyzes if adjacent feeders have enough capacity to pick up downstream loads, and
- Restores customers downstream of the isolated area.

5.2. S&C Intelliteam SG

Intelliteam is DA application that communicates between S&C switch controllers and performs automated switching on the following devices:

- IntelliRupter fault interrupters
- SCADA-Mate switches
- VISTA pad mount switches
- Remote supervisory PMH or PME switchgear

The software is programmed with the network topology and uses loss of voltage and fault current detection to determine the location of a fault. It then opens and closes switches to isolate the faulted section and restore power to the remaining sections.

The decision making is distributed and uses communications between the switch controllers. Status can be monitored by the SCADA system.

The programming software includes a simplified topology model of the system and be used to simulate faults and confirm response.

Intelliteam is a proprietary system and only works between S&C products. It can be interfaced to a substation feeder protection via an Intellinode Interface Module via DNP 3.0 protocol.

5.3. G&W Lazer

Lazer is a library of automation solutions for automatic switching ranging from simple automatic transfer schemes to complex system restoration schemes. It can be implemented in two ways:

- Script Based
- Model Based

Script based solution is customized to the configuration and is hard coded using SEL protection relays. Changes in equipment require a re-design and revised coding.

Model based solution is implemented using G&W's partnership with Survalent.

6.0 Deployment Strategy

Centralized decision-making using the existing SCADA system would provide Lakefront with a flexible system that allows integration with existing substations, existing and new pole and pad-mounted equipment while maintaining the ability to purchase high voltage hardware from multiple vendors.

The most practical opportunity for DA would be the installation of line reclosers or motor-operated switches on the Cobourg 27.6kV feeders. Similar devices could be installed on the 4.16kV feeders in Colborne.

Overhead feeders would require pole mounted equipment and underground feeders would require pad mounted equipment. Suitable devices are available from multiple equipment vendors. All would include a relay or controller, typically an SEL device.

6.1. Basic Approach

The simplest approach is to divide each feeder into two sections with a recloser in the middle of the feeder, and another recloser or normally open tie switch to an alternate feeder. This approach requires 1.5 switching points per feeder in addition to the feeder breaker. Using these devices to sectionalize permanent faults reduces the number of customers affected by a permanent outage by 50%. This approach could be used as the initial phase of DA.

The above approach can be expanded to divide each feeder into three or four sections with the installation of additional switching points. The number of sections will most likely be limited by the available budget.

6.2. Impact on Reliability

The reduction in the number of customers affected by a permanent outage will affect the reliability as shown in the table below. The values shown are based on the following assumptions for illustration purposes:

- 1,000 customers on the feeder
- 10,000 customers total
- 2 hour permanent outage
- AD sectionalizing and restoration to unfaulted sections in < 1 minute

Feeder Sections	Customers affected by Outage	SAIFI	SAIDI	CAIDI
1	1000	0.100	0.200	1.0
2	500	0.050	0.100	1.0
3	333	0.033	0.067	1.0
4	250	0.025	0.050	1.0

Dividing the feeder into 2 sections and restoring the unfaulted section in <1 minute reduces SAIFI and SAIDI by 50%. Dividing the feeder further into 3 or 4 sections provides additional improvement in reliability, but with diminishing returns.

6.3. Line Section Definition

To determine where reclosers or switches are to be located, the feeders are divided into line sections. Ideally, the feeders should be divided into line sections with equal characteristics. Considering the urban nature of the service territory, line sections with a similar number of customers and similar connected load would be appropriate. Customer type and size should be considered, as a large industrial and a small residence both count as one customer but have very different load.

The definition of line sections and feeders should include the future 27.6kV feeders in Cobourg after voltage conversion is completed.

6.4. Line Section Tie Locations

Once the line sections are defined the next step is to determine suitable locations for normally open tie points. This requires looking at the feeder routes and may require line construction to facilitate.

6.5. 44kV System

The Port Hope M2 and M4 feeder breakers are owned and operated by Hydro One and cannot be controlled by automation software.

Additional switches are required at the feeder delivery points to Lakefront Utilities to permit sectionalizing.

6.6. Critical Loads

In addition to line sections, supply to critical loads should be reviewed and main and alternate supplies determined. Critical loads would include the Northumberland Hills Hospital, water treatment and wastewater treatment facilities.

6.7. Communications

A combination of fiber, radio and cellular will provide reliable and secure network communications.

Communications medium selection for specific equipment and sites should be evaluated on a case-by-case basis, considering signal strength, capital and operating costs.

7.0 Software Requirements

7.1. Survalent FLISR

The main software requirement is to add licensing from Survalent for FLISR.

Implementation of FLISR also requires the following additional licenses:

- DMS – Distribution Automation
- NTP – Network Topology Processor
- SOG – Switching Orders and Guarantees

The OTS – Operator Training System is an optional license that provides the ability to test FLISR in a non-operational environment, basically an offline copy of the SCADA system. OTS can also be used for training new operations and engineering staff, reviewing events and planning system changes.

Additional information is included in the Appendices.

8.0 Timeline

The following timeline is proposed for DA implementation.

8.1. Year 1 (2027)

- Planning
  - Feeder configurations
  - Tie switch locations
  - Sectionalizer locations
  - Equipment selection
  - Communications
  - Relay Setting Study
- Procurement
  - Purchasing specifications
  - Communications system upgrades
  - Reclosers/switches – Phase 1

8.2. Year 2 (2028)

- Procurement
  - Reclosers/switches – Phase 2
- Installation
  - Reclosers/switches
- Programming
  - SCADA
  - Relay settings
- Commissioning
  - Reclosers/switches

8.3. Year 3 (2029)

- Procurement
  - Survalent Software
- Programming
  - Survalent Software set up and testing
- Commissioning
  - FLISR and supporting packages

9.0 Other Considerations

9.1. System Growth

The utility distribution system is not a static system. It is modified to accommodate new load connections, new developments, equipment replacements and other requirements. The DA implementation must accommodate system growth and future changes such as new feeders and changes in normal feeder configuration.

If the automation is hard coded then future changes will require significant re-writing of code otherwise the DA will not function correctly. We recommend using a model-based approach to provide the flexibility to accommodate future changes. This is typically done on a feeder by feeder basis.

9.2. Capacity Checking

The design must ensure that when the DA system automatically revises the feeder configuration it will not overload any circuit elements. The system load varies by time of day, day of the week and time of year. Capacity checking should be included in the implementation so that current load information is used to determine that system elements are not overloaded prior to initiating automatic switching.

9.3. High Accuracy Time Source

Although the IEDs include an internal clock the accuracy of those clocks is typically quite poor and the clock will drift over time. High accuracy time signals are available from GPS clocks such as the SEL-2401 which will provide time stamping with millisecond accuracy. This accuracy is very valuable when reviewing events and coordinating information from different sites for troubleshooting or confirming operation.

Including GPS clocks for field equipment is recommended.

9.4. Isolation for Work Protection

High voltage switching devices are used for Work Protection which requires a lockable visible open point. Reclosers do not have a visible open and so the device cannot be used for work protection. This presents an issue if the recloser location is required for isolation. Installing single blade disconnect switches in series with the recloser resolves this issue.

9.5. Cyber Security

The installation of a DA system including communications and end devices will need to address cyber security requirements.

9.6. Embedded Generation

There are number of embedded generators on the Lakefront distribution system. These have been connected to specific feeders based on a site-specific Connection Impact Assessment Study. Distribution Automation may result in the generators being transferred to a different feeder.

The following issues will be considered during the implementation stage:

- Lakefront will need to decide if generators will be permitted to operate while connected to alternate feeders.

- Transfer Trip protection from normal feeder protections will need to be blocked or re-configured if the generator is connected to an alternate feeder. DGEO supervision for reclosing will need addressed as well. (There are currently no transfer trip protections in-service at Lakefront).
- Impact on feeder loading. The embedded generators reduce feeder section loading while in-service. After a fault event this supply will not be available resulting in higher feeder loading. The large generators are SCADA monitored so their contribution can be included in the DA algorithm.

9.7. Cobourg 4.16kV system

The 4.16kV system in Cobourg is being converted to 27.6kV operation and the Kerr, Orr and D'Arcy substations will be decommissioned. These 4.16kV assets will not be included in DA planning.

As the load is converted to 27.6kV supply it will impact the topology of 27.6kV feeders. The future feeder configuration should be considered when planning the DA project.

9.8. Colborne

The Town of Colborne is supplied at 4.16kV from two substations. DA has a much lower return on investment at 4.16kV compared to 27.6kV due to the number of customers per feeder. Due to the difference in supply voltage, the number of customers per automated device at 4.16kV is 15% of the number of customers per device at 27.6kV.

DA is not being considered for the Colborne system due to the cost/benefit at 4.16kV.

9.9. End of Life of Existing Equipment

Most of the 900MHz radios and cellular modems are beyond commercial support and require replacement due to end-of-life concerns. They are currently performing fine and since their functioning is not critical to utility operations, they are not a current concern. A replacement program is required within the next year to address the issue.

If this equipment is used for DA purposes the reliability of communications becomes a higher priority. The replacement or upgrade of this equipment should be integrated with the DA implementation to ensure reliable operation.

Appendix A – Historic Reliability

Year	2021	2022	2023	2024
All Cause Codes				
SAIDI	1.11	32.09	3.55	6.40
SAIFI	1.06	1.69	3.02	3.15
Loss of Supply Adjusted				
SAIDI	0.99	31.67	2.80	3.22
SAIFI	0.60	1.48	2.02	1.33
Loss of Supply and Major Event Days Adjusted				
SAIDI	0.99	0.63	2.80	3.22
SAIFI	0.60	0.37	2.02	1.33

Appendix B – Budget

The following budgetary costs have been developed with input from potential vendors.

Item	Notes	Cost
Planning		$50k
SCADA System Upgrade	FLISR license plus support	$220k
44kV System	5 switching devices	$635k
27.6kV System	11 switching devices	$1,100k
Subtotal		$2,005k
Contingency	20%	$401k
Total		$2,406k

A breakdown of unit costs is included in the following pages.

SCADA System Upgrade

Description		Cost
NTP - Network Topology Processor	$	31,800
SOG - Switching Order & Guarantees	$	-
DMS	$	55,453
FLISR/LOV	$	-
OTS - Operator Training Simulator	$	25,000
Implementation Support	$	48,203
Programming	$	30,000
Commissioning	$	30,000
Total	**$**	**220,456**

Pole Mounted Recloser (27.6kV)

Description		Cost
G&W Viper	$	55,000
Installation	$	10,000
Communications Hardware	$	5,000
Communications Programming	$	5,000
Relay Settings & Programming	$	5,000
SCADA Programming	$	5,000
Commissioning	$	5,000
Engineering & PM	$	10,000
Total	**$**	**100,000**

Motor Operated Switch (27.6kV)

Description		Cost
S&C SCADA-Mate	$	65,000
Installation	$	10,000
Communications Hardware	$	5,000
Communications Programming	$	5,000
Relay Settings & Programming	$	5,000
SCADA Programming	$	5,000
Commissioning	$	5,000
Engineering & PM	$	10,000
Total	**$**	**110,000**

Motor Operated Switch (46kV)

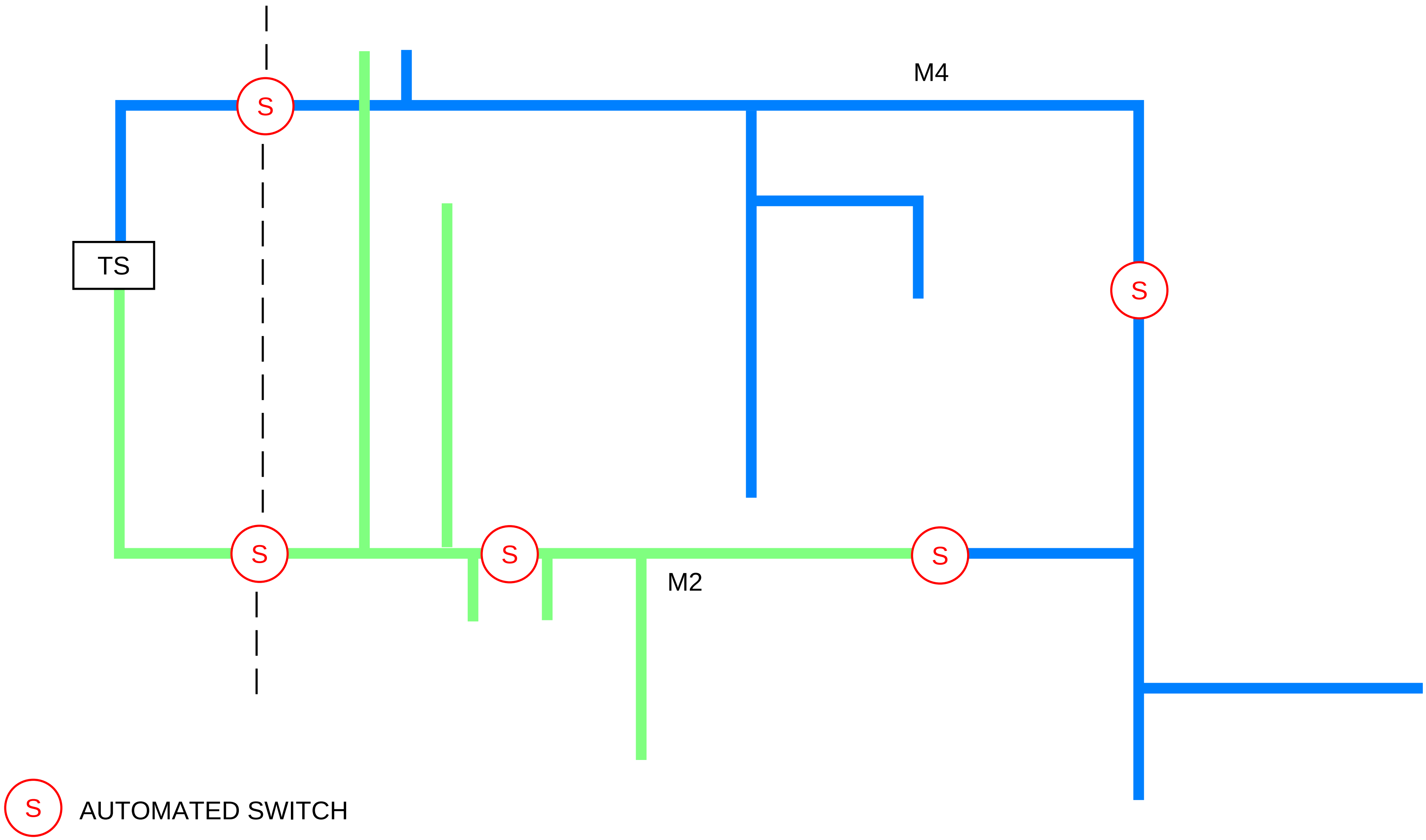
Description		Cost
S&C 46kV Alduti-Rupter, MO	$	82,000
Installation	$	10,000
Communications Hardware	$	5,000
Communications Programming	$	5,000
Relay Settings & Programming	$	5,000
SCADA Programming	$	5,000
Commissioning	$	5,000
Engineering & PM	$	10,000
Total	**$**	**127,000**

Pad Mount Switch (27.6kV)

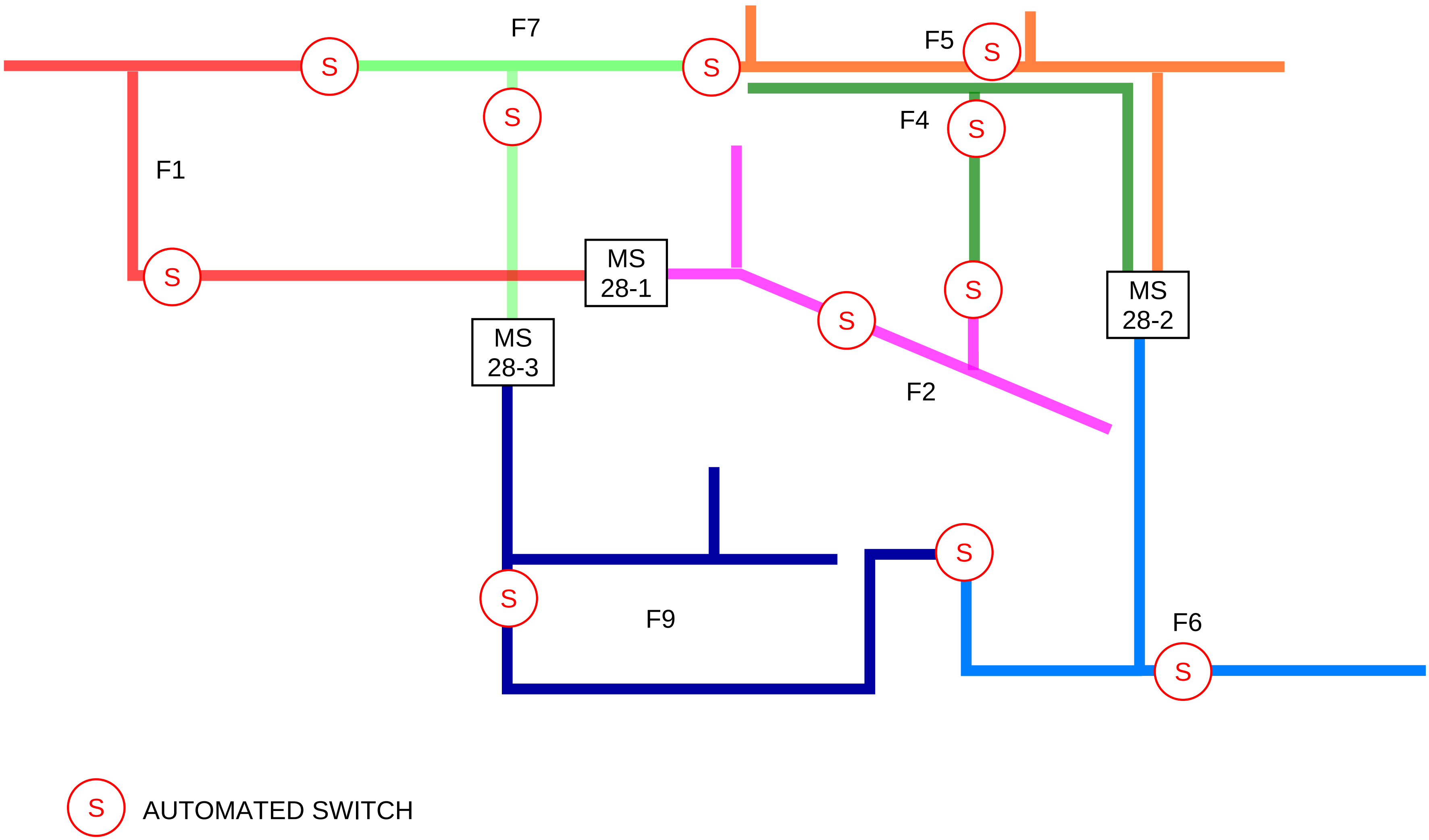
Description		Cost
G&W 4 way switch	$	200,000
Installation	$	30,000
Communications Hardware	$	5,000
Communications Programming	$	5,000
Relay Settings & Programming	$	10,000
SCADA Programming	$	5,000
Commissioning	$	10,000
Engineering & PM	$	10,000
Total	**$**	**275,000**

Appendix C – Proposed Switch Locations

- 44kV Distribution Automation Plan
- 27.6kV Distribution Automation Plan



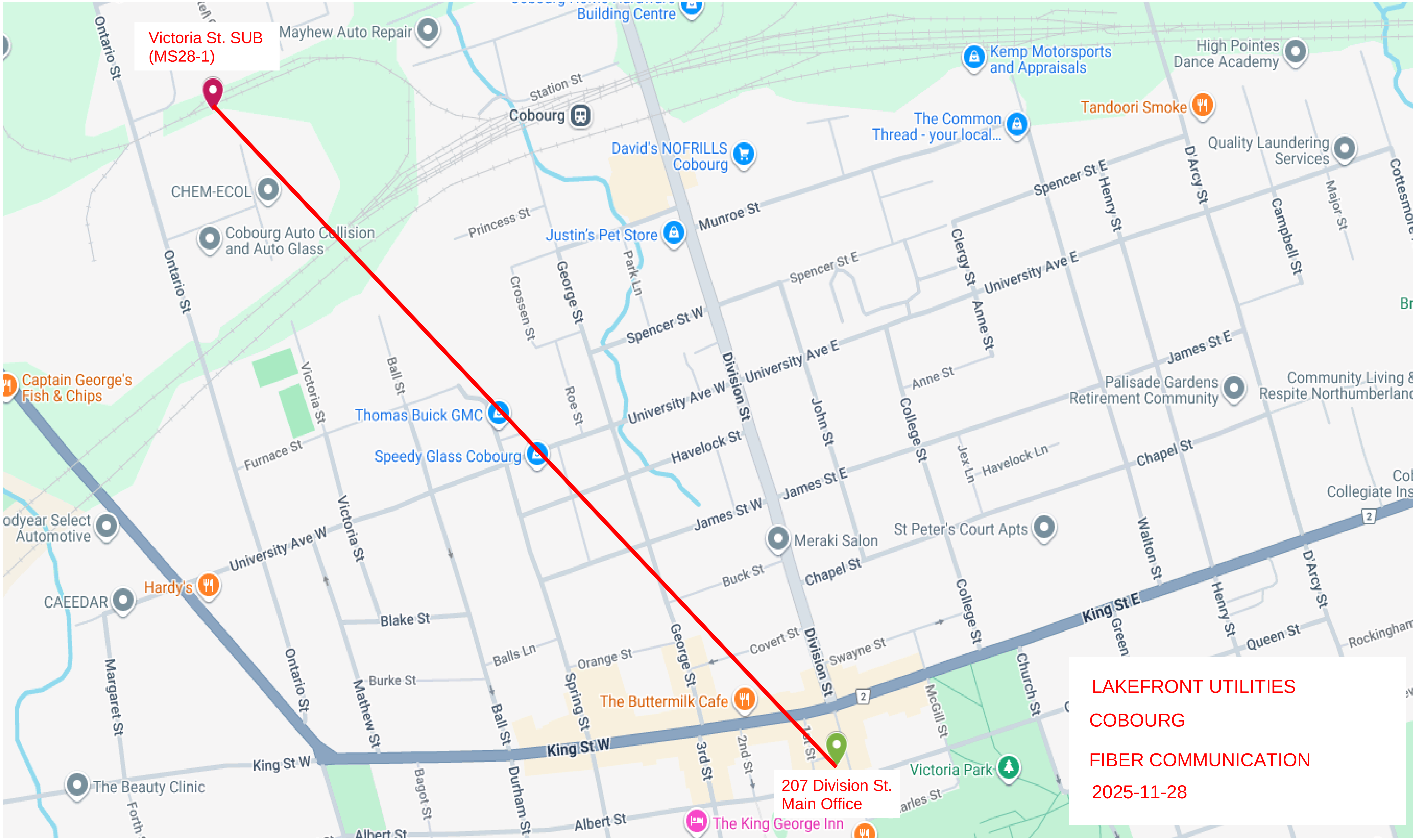
TOWN OF COBOURG
44kV DISTRIBUTION
AUTOMATION PLAN

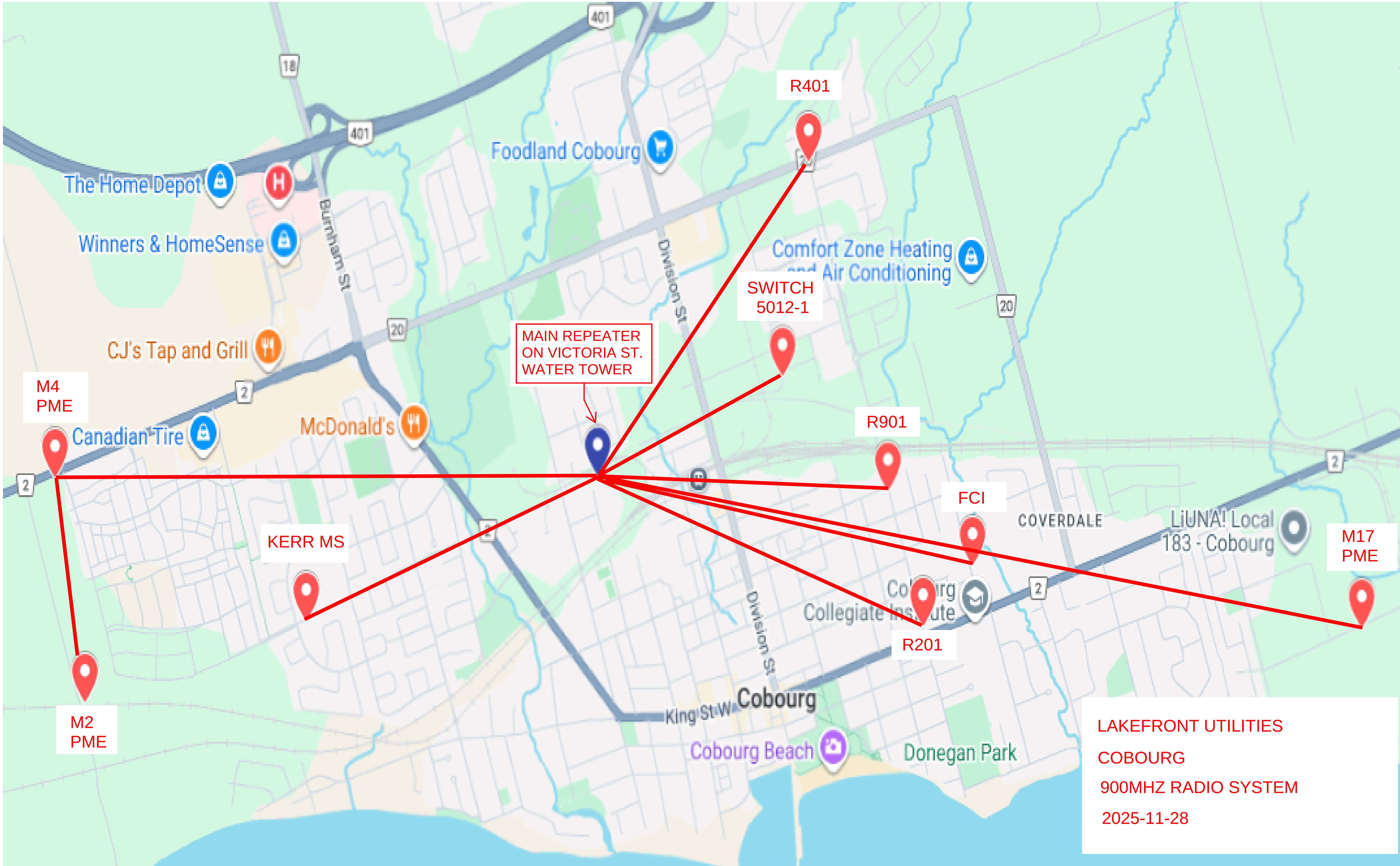


TOWN OF COBOURG
27.6kV DISTRIBUTION
AUTOMATION PLAN

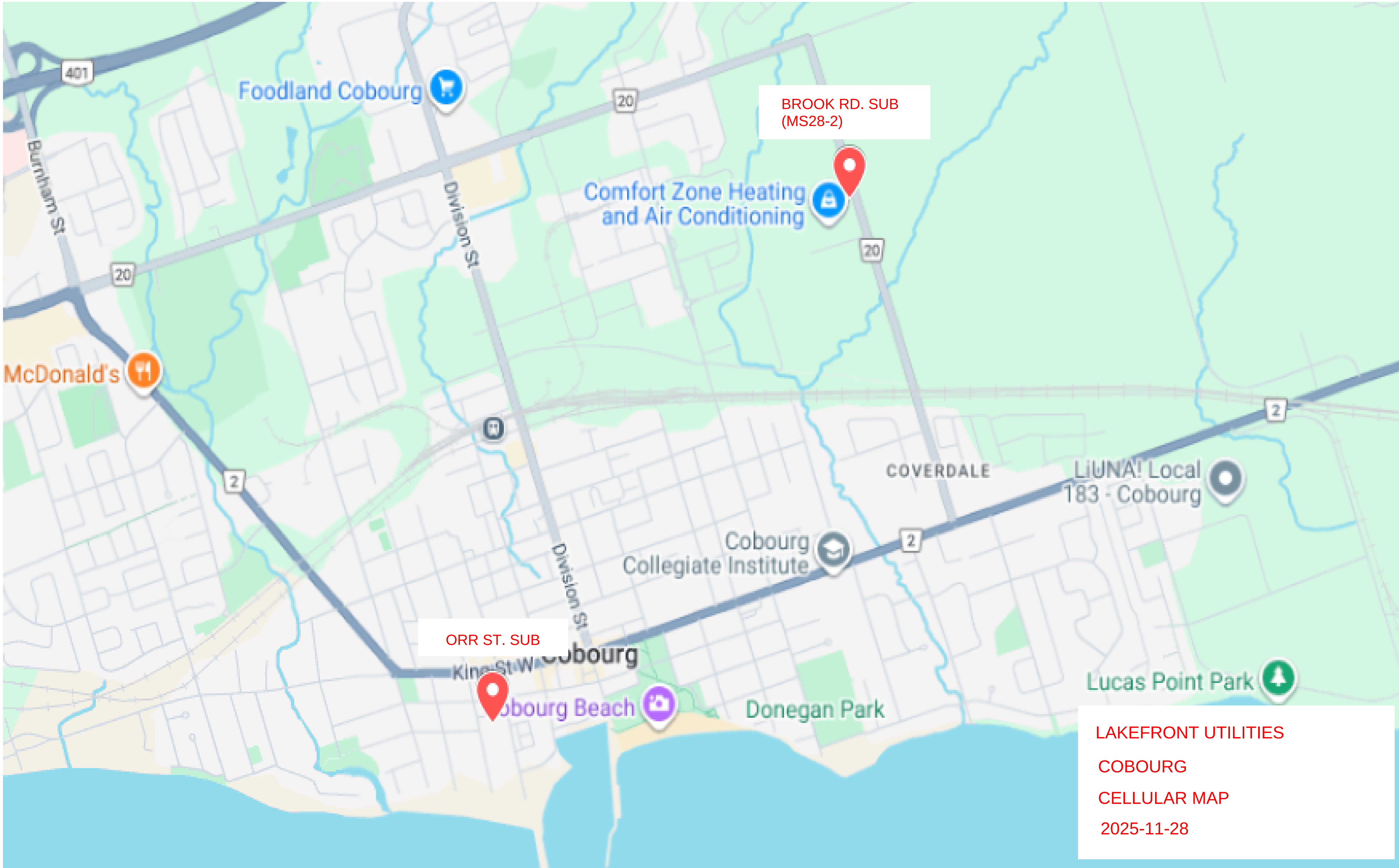
Appendix D – Communication Maps

1. Lakefront Utilities Cobourg – Fiber Communications
2. Lakefront Utilities Cobourg – 900 MHz Radio System
3. Lakefront Utilities Cobourg – Cellular Communications
4. Lakefront Utilities Colborne – Cellular Communications

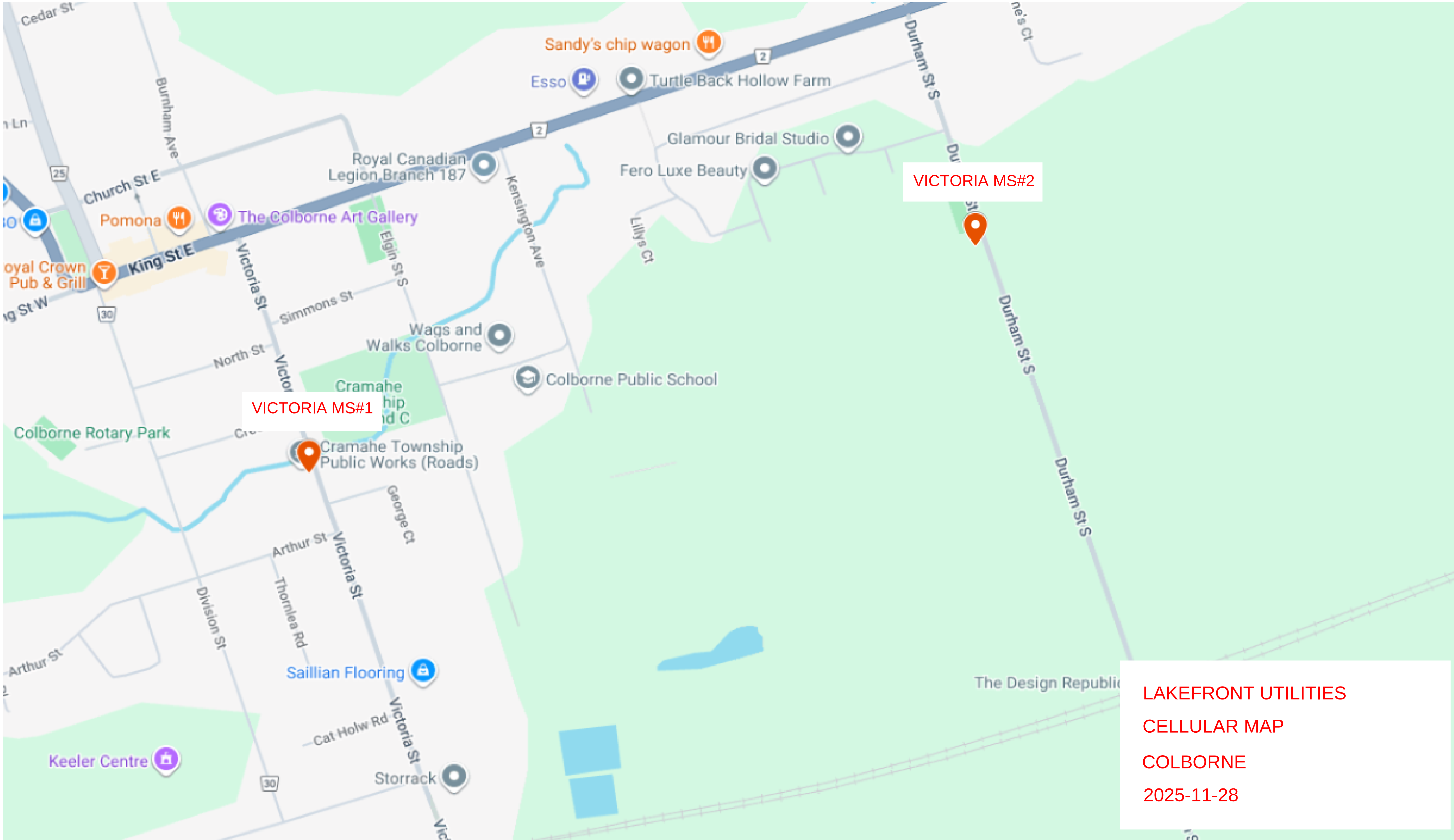

Victoria St. SUB
(MS28-1)
207 Division St.
Main Office
LAKEFRONT UTILITIES
COBOURG
FIBER COMMUNICATION
2025-11-28
Mayhew Auto Repair
Building Centre
Cobourg
Station St
Kemp Motorsports and Appraisals
High Pointes Dance Academy
Tandoori Smoke
The Common Thread - your local...
David's NOFRILLS Cobourg
Quality Laundering Services
CHEM-ECOL
Cobourg Auto Collision and Auto Glass
Princess St
Justin's Pet Store
Munroe St
Spencer St E
Spencer St W
University Ave E
University Ave W
Captain George's Fish & Chips
Thomas Buick GMC
Speedy Glass Cobourg
Furnace St
Havelock St
James St E
James St W
Palisade Gardens Retirement Community
Community Living & Respite Northumberland
Chapel St
Meraki Salon
St Peter's Court Apts
Hardy's
CAEEDAR
Blake St
Buck St
King St E
King St W
Burke St
Balls Ln
Orange St
Covert St
Swayne St
Queen St
The Buttermilk Cafe
Victoria Park
The Beauty Clinic
The King George Inn
Albert St
Division St
George St
Ontario St
Victoria St
College St
D'Arcy St
Henry St
Walton St
Church St
Margaret St
Mathew St
Ball St
Durham St



R401
SWITCH
5012-1
MAIN REPEATER
ON VICTORIA ST.
WATER TOWER
R901
FCI
M4
PME
KERR MS
R201
M17
PME
M2
PME
Foodland Cobourg
The Home Depot
Winners & HomeSense
Comfort Zone Heating
and Air Conditioning
CJ's Tap and Grill
McDonald's
Canadian Tire
COVERDALE
LiUNA! Local
183 - Cobourg
Cobourg
Collegiate Institute
Division St
Burnham St
King St W
Cobourg
Cobourg Beach
Donegan Park
401
18
20
2
LAKEFRONT UTILITIES
COBOURG
900MHZ RADIO SYSTEM
2025-11-28



BROOK RD. SUB
(MS28-2)
ORR ST. SUB
LAKEFRONT UTILITIES
COBOURG
CELLULAR MAP
2025-11-28
Foodland Cobourg
Comfort Zone Heating
and Air Conditioning
McDonald's
Burnham St
Division St
COVERDALE
LiUNA! Local
183 - Cobourg
Cobourg
Collegiate Institute
King St W
Cobourg
Cobourg Beach
Donegan Park
Lucas Point Park
401
20
2


VICTORIA MS#2
VICTORIA MS#1
LAKEFRONT UTILITIES
CELLULAR MAP
COLBORNE
2025-11-28
Sandy's chip wagon
Esso
Turtle Back Hollow Farm
Glamour Bridal Studio
Fero Luxe Beauty
Royal Canadian Legion Branch 187
Pomona
The Colborne Art Gallery
King St E
Church St E
Wags and Walks Colborne
Colborne Public School
Colborne Rotary Park
Cramahe Township Public Works (Roads)
Saillian Flooring
Keeler Centre
Storrack
The Design Republic
Durham St S
Victoria St
Kensington Ave
Simmons St
North St
Arthur St
Division St
Thornlea Rd
Cat Holw Rd
George Ct
Elgin St S
Burnham Ave
Cedar St
Lillys Ct

Appendix E – Survalent FLISR Software Brochure

SurvalentONE

Fault Location, Isolation, and Service Restoration & Loss of Voltage

Distribution Automation Software that Monitors Voltage, Identifies and Isolates Faults, and Resupplies Power or Loss of Voltage

Survalent.

Utiliverse™ ecosystem

Survalent.

Minimize Outage Impact & Duration by Rerouting Power in Seconds

When a tree falls on a power line, field crews may take several hours to locate the problem and repair the damage. Meanwhile, thousands of frustrated customers must put their lives and businesses on hold until power is restored. In response, utilities are turning to fault location, isolation, and service restoration (FLISR) technology.

Survalent's FLISR solution is based on a sophisticated fault location algorithm that uses telemetry from field devices, in tandem with the SurvalentONE ADMS network model, to rapidly identify faults, isolate them, and then automatically resupply as many customers as possible.

With SurvalentONE FLISR in the control room, utilities can turn sustained outages into momentary events resulting in greater network reliability, lower CMI, and increased customer satisfaction.

Loss of Voltage

SurvalentONE FLISR includes our Loss of Voltage (LOV) application, which monitors the network for sudden voltage drops. When the LOV algorithm detects a loss of voltage in a substation or elsewhere in the grid, the application will attempt to isolate the cause of the voltage loss from the network and reroute power to as many customers affected as possible.

Minimize Outage Duration & Extent

When lockout devices are tripped, SurvalentONE FLISR immediately limits the severity of the ensuing power outage, restoring service to non-faulted areas in seconds versus hours.

Less downtime means less financial impact on customers, especially large commercial & industrial (C&I) customers who incur significant losses during even the briefest service interruption.

By keeping electricity flowing to more customers for more hours of each day, utilities simultaneously increase their revenues and improve performance metrics such as CMI, SAIDI, and SAIFI, which are used by regulators and customers to assess the quality of the network.

Increase Revenue by Attracting Premium Power Customers

With SurvalentONE FLISR, utilities can attract large C&I customers to set up shop in their service area by providing reliability guarantees as part of a contracted service level agreement.

Reduce Operating Costs

Control room operators no longer have to spend time diagnosing faults and trying to estimate their locations because SurvalentONE FLISR can do it all for them in seconds. The solution narrows down fault locations to a smaller search area, allowing field crews to find and fix problems faster which reduces labor costs.

By automatically switching as many customers as possible downstream of the fault to neighboring feeders, SurvalentONE FLISR frees up crews to focus on the root cause of each fault. Since field crews drive fewer miles per rollout, less fuel is used and there is less wear and tear on service vehicles and equipment.

Benefits

- Rapid service restoration for customers
- Increased customer satisfaction
- Improved CMI, SAIFI, SAIDI & related performance indices
- Increased revenues through more network uptime and premium power programs
- Lower field service costs
- Compliance with regulatory standards
- Better decision-making in the control room
- Coordinate with other distribution automation solutions

Key Features

- Seamless integration with SurvalentONE ADMS
- Centralized FLISR solution
- Ability to enable/disable the application on a per feeder basis or globally
- Semi-automatic and automatic modes of operation
- Vendor agnostic for field devices
- Sophisticated fault location algorithm
- Comprehensive FLISR operations log and switch order created for every FLISR event
- Enhanced testing capabilities
- Optional Integration with SurvalentONE Distribution Power Flow and Distribution State Estimation to enhance service restoration analysis

FLISR detected the fault, isolated the area, then closed a neighboring tie switch, thereby restoring power to affected customers within seconds.

Better Software.
Better Decisions.

With Survalent, you can control your critical network operations with confidence. We're the most trusted provider of advanced distribution management systems (ADMS) and substation automation for electric, water/wastewater, oil & gas, renewable energy, and transit utilities across the globe.

Over 800 utilities in 40 countries rely on the SurvalentONE platform to effectively operate, monitor, analyze, restore, and optimize operations. By supporting critical utility operations with a fully integrated solution, our customers have significantly improved operational efficiencies, customer satisfaction and network reliability. Our comprehensive substation automation solution, Survalent StationCentral, delivers advanced control and monitoring for enhanced network performance and protection.

Our unwavering commitment to excellence and to our customers has been the key to our success for over 60 years.

100% Project Delivery. We Guarantee It. Ask Us How.

Survalent.

info@survalent.com · survalent.com · 905-826-5000

Utiliverse™ ecosystem

Lakefront Utilities Inc.

Asset Condition Assessment

Cobourg, Ontario

Technical Report

ACA Report

BBA Document No. / Rev.: 201810001-000000-40-ERA-0000

March 5th, 2026

Final Report

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0	Preliminary issued for review	2026-03-04
1	Final Report	2026-03-06

Executive Summary

Context of the Study

Lakefront Utilities Inc. ("LUI") is an electricity distributor serving approximately 11,000 customers in the Town of Colborne and the Village of Colborne. LUI engaged BBA E&C Inc. ("BBA"), formerly METSCO Energy Solutions Inc., to prepare a comprehensive Asset Condition Assessment ("ACA") study for the major assets comprising LUI's distribution system. The ACA is one of the key inputs in the preparation of LUI's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

Scope of the Study

BBA's work included consultations with LUI subject matter experts to define the Health Indices ("HI") appropriate for the asset types, review and consolidation of the client's data sets, analysis of LUI's asset records to calculate the HI values, and preparation of the final document. In total, BBA assessed the following asset classes:

- Distribution Assets
    - Wood poles;
    - Concrete poles;
    - Composite poles;
    - Overhead primary conductors;
    - Underground primary cables;
    - Pole-mount transformers; and
    - Pad-mount transformers;
- Station Assets
    - Station power transformers;
    - Station service transformer;
    - Station circuit breakers;
    - Station reclosers;
    - Station switches;
    - Station switchgears; and
    - Station facilities.

All data used in the study is maintained by LUI as part of its regular asset management practices and was collected by LUI or its contractors in compliance with Distribution System Code requirements. Data used in this study are valid as of September 2025.

Methodology and Findings

For all asset classes that underwent assessment, BBA used a consistent scale of asset health from "Very Good" to "Very Poor". The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions recommended for the asset management team at LUI.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal or no maintenance
[70-85)	Good	Significant Deterioration of some components	Normal or no maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, BBA calculated Health Indices for every asset class in the scope of its assessment using a selected HI model. The HI for each asset class is made up of available and relevant "Degradation Factors" – individual characteristics of the state of an asset's components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall HI made up by the parameter. BBA's findings for each asset class were developed using this methodology, as described in more detail in Section 4. The consolidated results of the ACA are summarized in Figure 0-1.

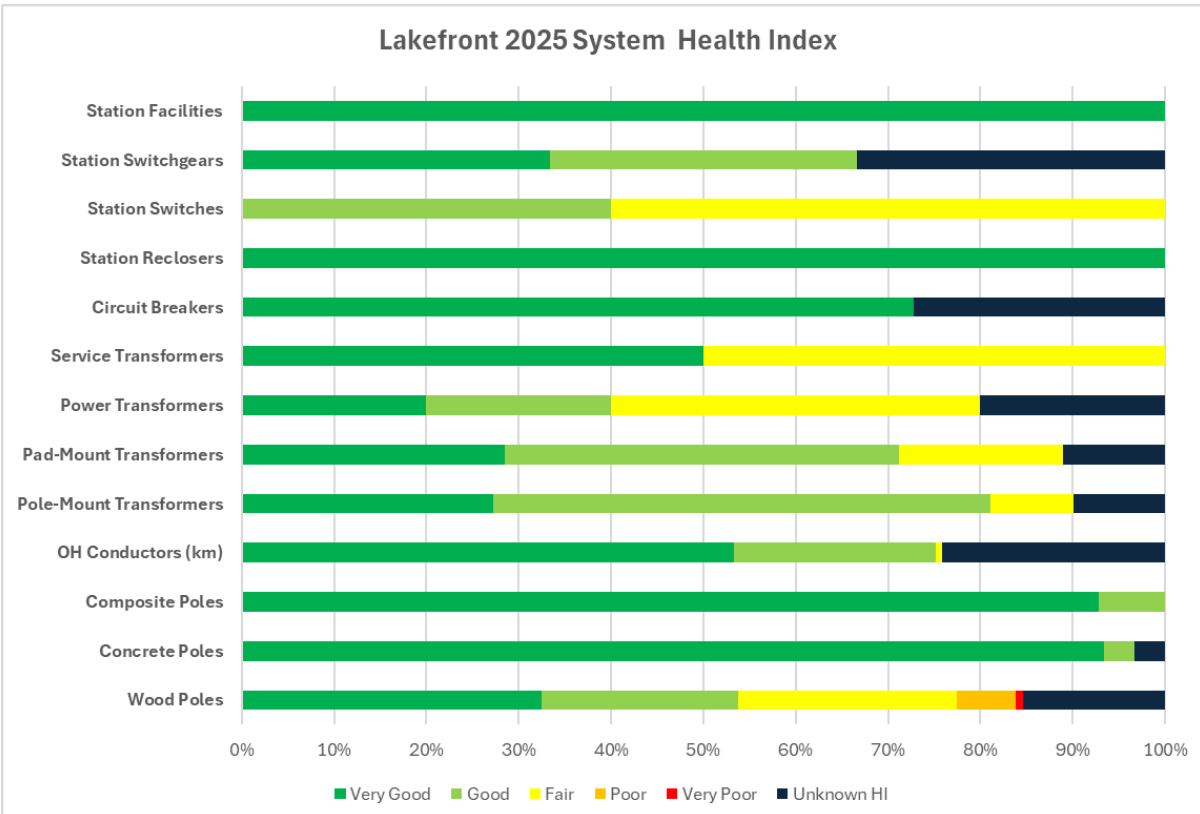

Figure 0-1: Health Index Results

As the figure above indicates, the majority of assets in LUI's network are found to be in Fair or better condition. There are however some assets which have data availability issues which could obscure the true health of some individual assets. Recommendations for improvements in data collection will be provided as part of this report. Wood poles were the only asset class with units found to be in "Poor" and "Very Poor" condition. For UG cables only service age data was available, therefore it was not possible to develop a HI formulation. As such, the HI results for these are not presented in the figure above or Table 0-2, which presents the numerical HI summary for each asset class. For each asset class, the following details are listed: total population, average Data Availability Index ("DAI"), and the HI distribution. A DAI is a percentage of Degradation Factor data available for an asset or asset class, weighted by their contributions to the HI formulation. A DAI of 100% for an asset indicates that all data is available. As discussed in Section 2.3, if the DAI for an asset is less than 70%, a valid HI cannot be calculated.

Table 0-2: Asset Condition Assessment Overall Results

Asset Category	Population	HI Distribution (%)						Average DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	3688	32%	21%	24%	6%	1%	15%	91%
Concrete Poles	30	93%	3%	0%	0%	0%	3%	99%
Composite Poles	152	93%	7%	0%	0%	0%	0%	100%
Overhead Conductors (km)	147	53%	22%	1%	0%	0%	24%	90%
Pole-Mount Transformers	618	27%	54%	9%	0%	0%	10%	92%
Pad-Mount Transformers	680	29%	43%	18%	0%	0%	11%	91%
Station Assets								
Power Transformers	5	20%	20%	40%	0%	0%	20%	85%
Service Transformers	2	50%	0%	50%	0%	0%	0%	100%
Circuit Breakers	11	73%	0%	0%	0%	0%	27%	89%
Station Reclosers	3	100%	0%	0%	0%	0%	0%	100%
Station Switches	5	0%	40%	60%	0%	0%	0%	96%
Station Switchgears	3	33%	33%	0%	0%	0%	33%	82%
Station Facilities	5	100%	0%	0%	0%	0%	0%	100%

LUI's Current Health Index Maturity and Continuous Improvement

Overall, LUI's asset data collection practices would benefit from some improvement in GIS data availability and substation inspection data availability. Section 5 of this report identifies further opportunity for HI and data availability improvements.

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LIST OF ACRONYMS

Acronym	Description
ACA	Asset Condition Assessment
AM	Asset Management
BBA	BBA E&C Inc.
DAI	Data Availability Index
DGA	Dissolved Gas Analysis
EOL	End of Life
GIS	Geographic Information System
HI	Health Index
IR	Infrared
ISO	International Organization for Standardization
LUI	Lakefront Utilities Inc.
PD	Partial Discharge
OH	Overhead
SAMPs	Strategic Asset Management Plans
UG	Underground

1. Introduction

This report summarizes the results of an Asset Condition Assessment ("ACA") carried out by BBA E&C Inc. ("BBA"), formerly METSCO Energy Solutions Inc., on behalf of Lakefront Utilities Inc. ("LUI"). BBA is an industry expert in ACA and Asset Management ("AM") practices, with extensive experience conducting ACAs, developing AM plans, and implementing AM frameworks for organizations across North America. BBA's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions.

LUI is an electricity distributor operating in the Town of Colborne and the Village of Colborne, serving approximately 11,000 customers. LUI owns and operates 7 substations at various distribution voltages within its service territory. LUI does not own any Transmission stations, as its distribution system assets are fed from Hydro One owned Transmission Stations. LUI engaged BBA to prepare a comprehensive Asset Condition Assessment ("ACA") study for the major assets comprising LUI's distribution system. The ACA is one of the key inputs in the preparation of LUI's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

To assist LUI with further asset condition data integration efforts, Section 5 of this report contains a set of recommendations for the utility's management to consider going forward.

The asset classes covered in the report include the following:

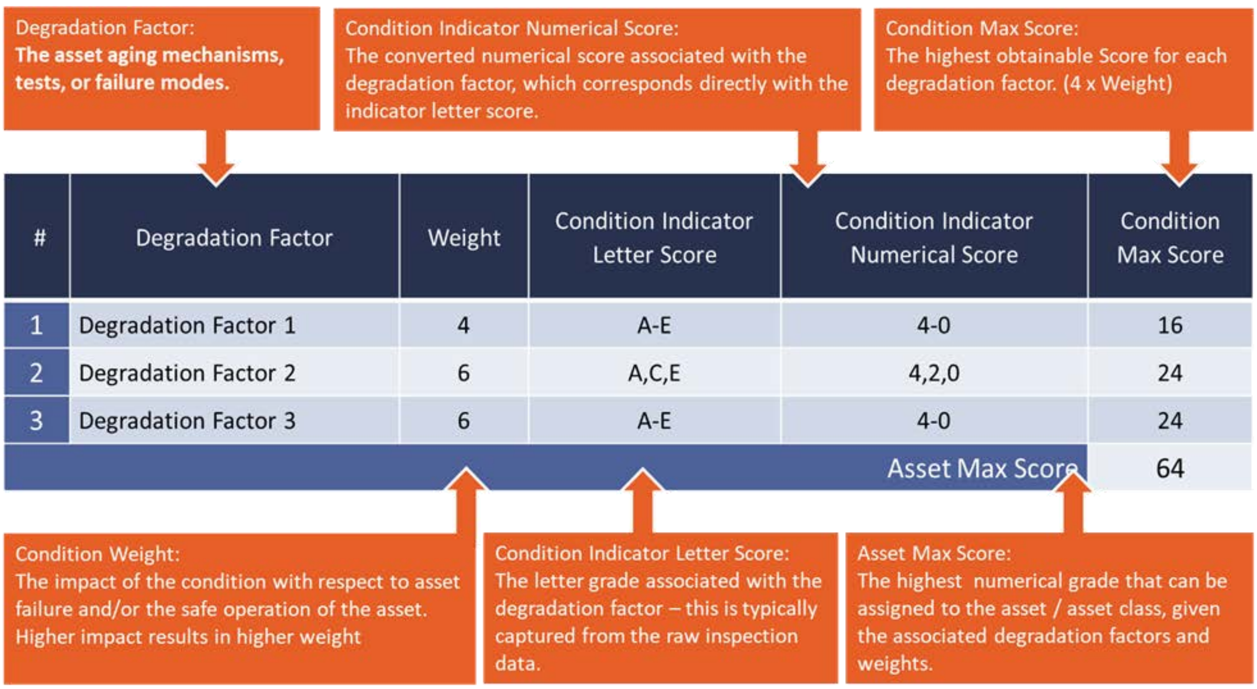
- Distribution Assets
    - Wood poles;
    - Concrete poles;
    - Composite poles;
    - Overhead primary conductors;
    - Underground primary cables;
    - Pole-mount transformers; and
    - Pad-mount transformers.

- Station Assets
  - Station power transformers;
  - Station service transformer;
  - Station circuit breakers;
  - Station reclosers;
  - Station switchgears;
  - Station switches; and
  - Station facilities.

2. Asset Condition Assessment Methodology

2.1 Degradation Factors

To determine the overall HI for an asset, formulations are developed based on "Degradation Factors" that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each Degradation Factor to indicate the amount of influence the condition has on the overall health of the asset. Figure 2-1 provides an example of an HI formulation table.



#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Figure 2-1: HI Formulation Components

Degradation Factors of the asset are characteristic properties that are used to derive the overall HI. They are specific and uniquely graded to each asset class. Additionally, some Degradation Factors can be comprised of "Sub-Degradation Factors". For example, the Degradation Factor "Oil Quality" for power transformers includes multiple Sub-Degradation Factors: "Interfacial Tension", "Dielectric strength", and "Water Content". In this case, the lowest Sub-Degradation Factor score is used as the score for the Degradation Factor.

The scale used to determine an asset's score for a Degradation Factor is called the "Condition Indicator". Each Degradation Factor is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a Condition Indicator of 4 represents the best grade, whereas a Condition Indicator of 0 represents the worst grade.

The conversion from alphabetic ranking to numerical grade and a brief characteristic description of the grade is provided below:

Table 2-1: HI Score Grading

A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score} \right) x\ 100\% \qquad (1)$$

where *i* corresponds to the Degradation Factor number, and the HI is a percentage representing the remaining life of the asset.

2.2 Health Index Interpretation

BBA's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset. To assign each asset into one of the categories, BBA constructs numerical HI for each asset class that captures information on individual Degradation Factors contributing to that asset's declining condition over time. Condition Indicators assigned to each Degradation Factor are expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual Condition Indicators, with each of the five condition categories ("Very Good", "Good", "Fair", "Poor", "Very Poor") corresponding to a numerical band that are roughly equivalent to the percentage of remaining useful life for the given asset. For example, the condition score of Very Good indicates assets with HI between 100% and 85%, whereas the condition score of Very Poor indicates assets with calculated HI between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 2-2 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing, or replacing the asset prior to failure.

Table 2-2: HI Ranges and Corresponding Asset Condition

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal or no maintenance
[70-85)	Good	Significant Deterioration of some components	Normal or no maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

2.3 Data Availability

BBA supplemented its HI findings with the calculation of a Data Availability Index ("DAI"), which is a measure of the availability of Degradation Factor data for a specific asset scaled by their weights in the HI formulation. The DAI is determined by comparing the sum of the weights of the Degradation Factors available to the total weight of the Degradation Factors used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\% \tag{2}$$

where *i* corresponds to the Degradation Factor number and *α* is the availability of coefficient (*α* =1 when datum is available *α* =0 when datum is unavailable).

An asset with all Degradation Factor data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. In the case where the DAI for an asset is less than 70%, a valid HI cannot be calculated. Assets without a valid HI were extrapolated based on the known HI within the same ten-year age bands to estimate the distribution of health across the entire asset class. In cases where both age is unknown and the HI is invalid, the extrapolation is done based on the full set of assets with known HI scores instead of using ten-year age bands.

2.4 Project Execution

The HI formulations calculated in this study are based only on available data provided by LUI. BBA's execution path in completing the ACA study can be separated into four phases described below:

1. *Initial Information Gathering* – including initial interviews with LUI staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with LUI subject matter experts through a series of interviews.

2. *Database Construction* – activities to construct a database of condition-related information for each LUI asset amongst the in-scope asset classes using the provided data sources. This includes consolidation of LUI's asset inspection and maintenance records, databases containing results of technical tests performed by LUI and its contractors, and the entire database from the Geographic Information System ("GIS").

3. *HI and DAI Calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, BBA calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from LUI to improve the accuracy of the asset health calculation, where applicable.

4. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3. Input Data

To assess the demographics and establish the unit population of LUI's distribution system assets, BBA was provided with LUI's asset demographics from their current Geographic Information System ("GIS"), asset inspection and maintenance records, test records stored in an Excel databases, and PDF copies of test reports. Historical records for the assets were dated to complete a full lifecycle of the asset population. This means that if an asset class has an inspection lifecycle of three years, LUI provided BBA with three years of historical data covering the entirety of the service territory to have a complete set of available data. This dataset contained the last calculated degradation score for a particular asset as well as the most recent test results which were translated to a score and ultimately a HI. Most of this data came from sources such as equipment inspection forms completed by LUI staff or contractors or results of specific technical tests such as Dissolved Gas Analysis ("DGA") of transformer oil.

Additionally, BBA was provided with historical operating data for assets that required operating information for the HI calculation. Examples of operating data used include historical loading information for transformers.

3.1 Continuous Improvement

The application of rigorous AM processes can provide several benefits to an organization including, but not limited to: realized financial savings; better classified and managed risk among assets; better-informed investment decisions; demonstrated compliance to standards and mandates among the asset base; increased public and worker safety; as well as working towards corporate reliability targets.

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant stakeholders. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical expertise, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency to effectively manage its distribution infrastructure. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio, continuous improvement in the quantity and quality of asset data and data collection procedures, SAMPs, and further integration into all aspects of an organization's activities as it grows and evolves over time.

[1] ISO 55000 – Asset management – Overview, principles and terminology

4. Asset Condition Assessment Results

This section presents the current HI formulation, age demographics, and HI results for each asset class. The total system results are summarized in Table 4-1 and Figure 4-1.

Table 4-1: ACA Results

Asset Category	Population	HI Distribution (%)						Average DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	3688	32%	21%	24%	6%	1%	15%	91%
Concrete Poles	30	93%	3%	0%	0%	0%	3%	99%
Composite Poles	152	93%	7%	0%	0%	0%	0%	100%
Overhead Conductors (km)	147	53%	22%	1%	0%	0%	24%	90%
Pole-Mount Transformers	618	27%	54%	9%	0%	0%	10%	92%
Pad-Mount Transformers	680	29%	43%	18%	0%	0%	11%	91%
Station Assets								
Power Transformers	5	20%	20%	40%	0%	0%	20%	85%
Service Transformers	2	50%	0%	50%	0%	0%	0%	100%
Circuit Breakers	11	73%	0%	0%	0%	0%	27%	89%
Station Reclosers	3	100%	0%	0%	0%	0%	0%	100%
Station Switches	5	0%	40%	60%	0%	0%	0%	96%
Station Switchgears	3	33%	33%	0%	0%	0%	33%	82%
Station Facilities	5	100%	0%	0%	0%	0%	0%	100%

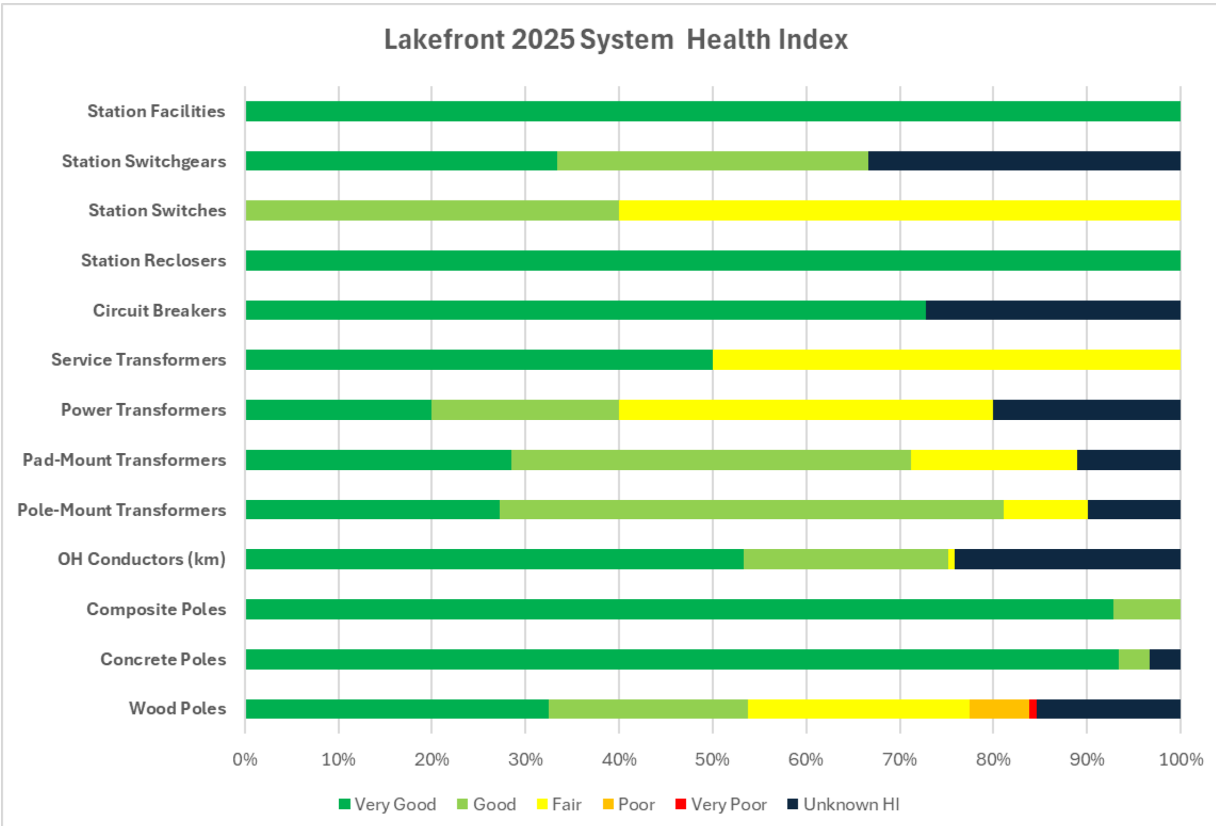


Figure 4-1: System HI Results

4.1.1 Wood Poles

Wood poles are an integral part of LUI overhead distribution system. They support the majority of overhead distribution lines, overhead transformers, switches, streetlights, all third-party attachments as per LUI's Joint Use Agreements, and majority of LUI's underground system. Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather, which can impact the mechanical strength of the pole (Fiber strength). The HI for wood poles is estimated by considering a combination of EOL criteria summarized in Table 4-2.

Table 4-2: Wood Pole HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	2	A,B,C,E	4,3,2,0	8
Wood Rot	2	A,B,C,E	4,3,2,0	8
Out of Plumb	1	A,E	4,0	4
Pole Treatment	1	A,C,D,E	4,2,1,0	4
			Total score	40

LUI owns 3,688 wood poles within its service territory. Figure 4-2Error! Reference source not found. presents the age distribution for in-service wood poles.

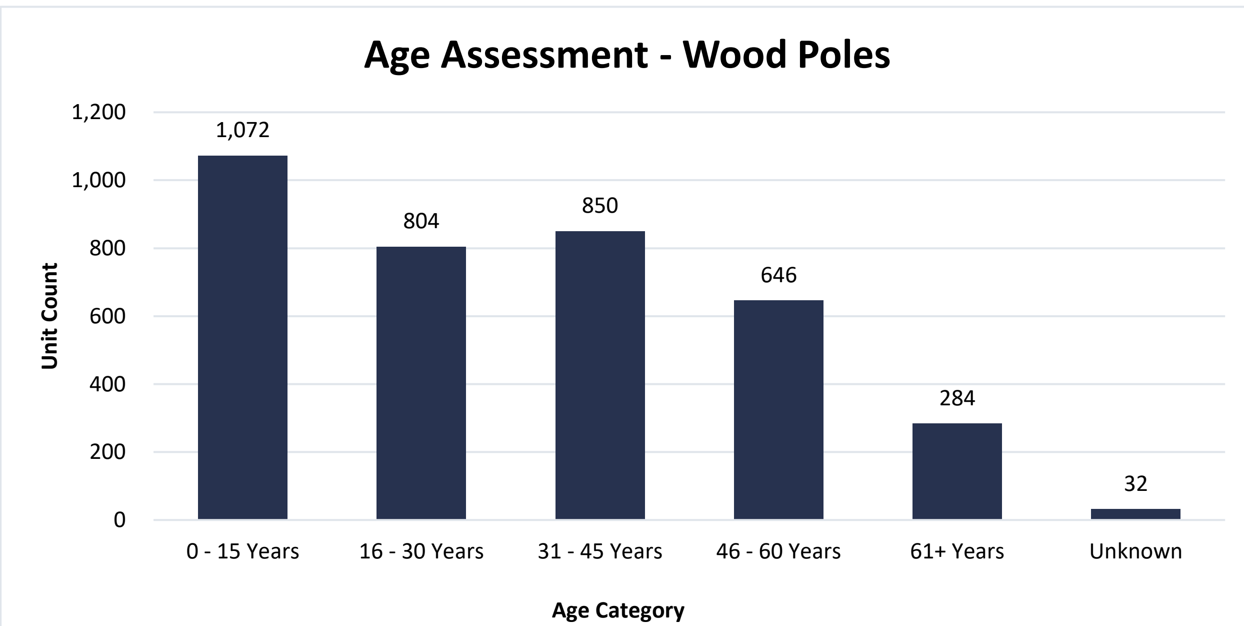


Figure 4-2: Wood Pole Age Demographics

LUI's pole maintenance and nameplate data were used to calculate the HI results for LUI's wood poles. Degradation Factors include service age, pole treatment, wood rot presence, mechanical defects, and pole lean. A visual inspection record notes the presence of wood rot/decay developed on the pole's external surface. The presence of wood rot signifies there is a high moisture content surrounding the pole and impacts the pole's strength. Additionally, visual inspections note for the following mechanical defects found on wood poles, and summarized in overall condition:

- Crossarm Condition;
- Insect Infestation;
- Cracking;
- Woodpecker Damage;
- Pole-Top Condition;
- Fire Damage; and
- Hardware Condition.

If visual inspection results were left blank for an asset it was assumed that no deficiencies were noted and the asset received a grade of 'A'.

The overall HI distribution for the wood poles is presented in Figure 4-3Error! Reference source not found.. The HI results show that most assets are in Very Good to Fair condition.

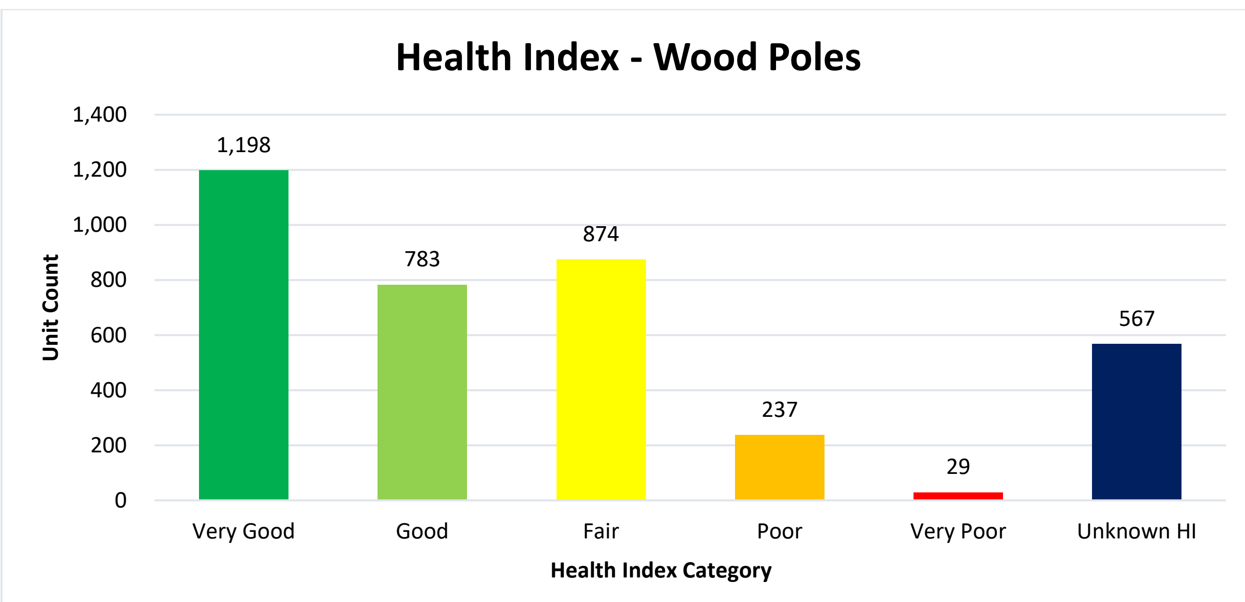


Figure 4-3: Wood Pole HI Results

The average DAI for the asset class is 91%. Table 4-3 presents the DAI of individual Degradation Factors used for the wood poles HI framework.

Table 4-3: Wood Pole Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Service Age	99%
Overall Condition	85%
Wood Rot	85%
Out of Plumb	85%
Pole Treatment	87%

4.1.2 Concrete Poles

Like wood poles, concrete poles support the overhead distribution system. Concrete poles have significantly greater strength than typical wood poles and have a longer service life. However, concrete poles are very heavy and are costlier to transport and install, hence fewer are in-service compared to wood poles. The HI for concrete poles is calculated by considering a combination of EOL criteria summarized in Table 4-4.

Table 4-4: Concrete Pole HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Out of Plumb	1	A,E	4,0	4
Rusting/Corrosion	2	A,B,C,E	4,3,2,0	8
Defects	2	A,B,C,E	4,3,2,0	8
			Total score	32

LUI owns 30 concrete poles within its service territory. Installation date is known for most of the in-service population. Figure 4-4 presents the age distribution for concrete poles.

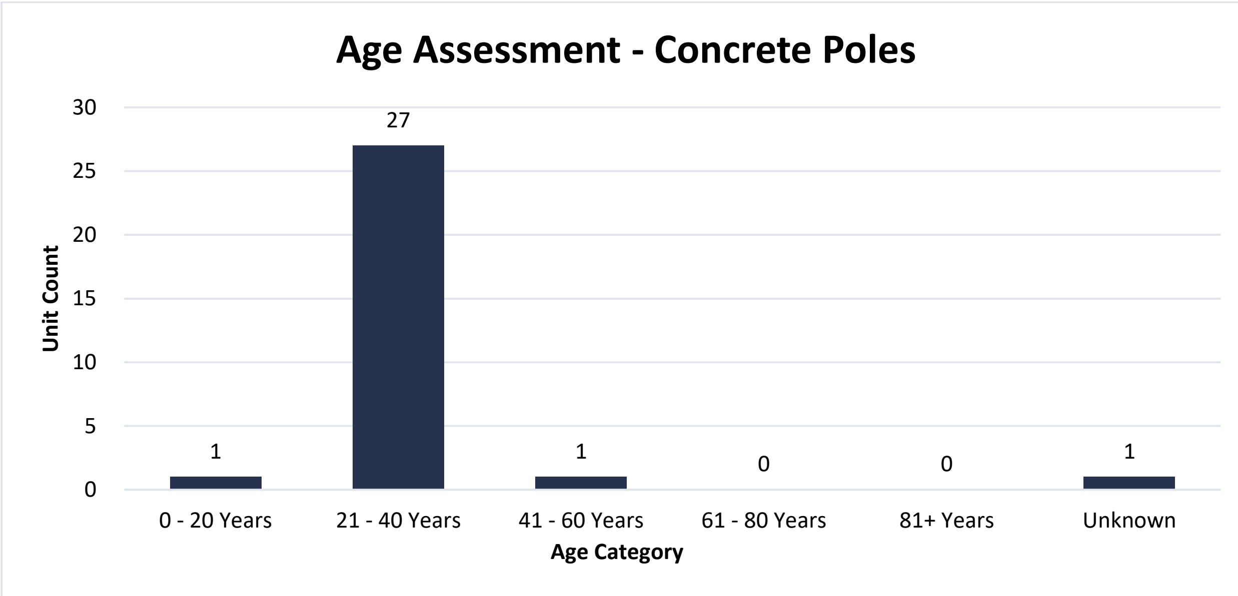


Figure 4-4: Concrete Pole Age Demographics

LUI's maintenance and nameplate information was used to calculate the HI results for concrete poles. Degradation Factors include service age, defects, and evidence of leaning for concrete poles. The HI formulation for concrete poles does not contain a quantitative measure of remaining strength as found with the wood poles. Hence, it is more dependent on visual inspection of defects.

Visual inspections note for the following defects found on concrete poles:

- Leaningl;
- Rusting/Corrosion; and
- Defects.

If visual inspection results were left blank for an asset it was assumed that no deficiencies were noted and the asset received a grade of 'A'.

The overall Health Index distribution for the concrete poles is presented in Figure 4-5. Almost all concrete poles have a valid HI score. All poles with valid HI scores are in either Very Good or Good condition.

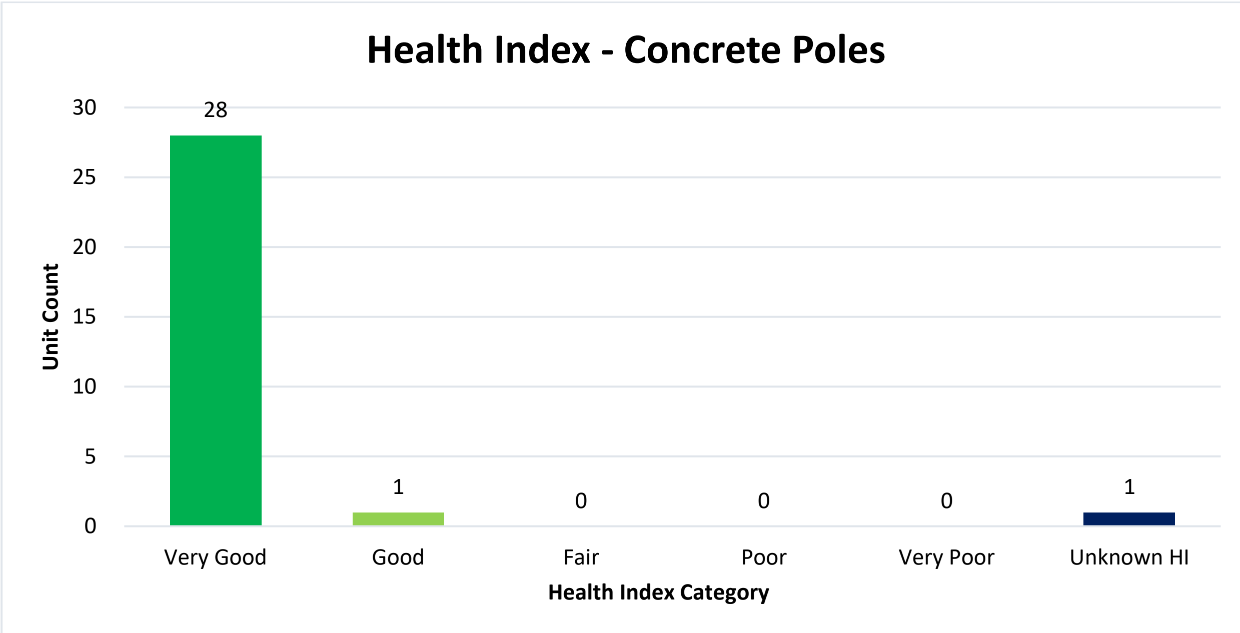


Figure 4-5: Concrete Pole HI Results

The average DAI for the asset class is 99%. Table 4-7 presents the DAI of individual Degradation Factors used for the concrete poles HI framework.

Table 4-5: Concrete Pole Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Service Age	97%
Rusting/Corrosion	100%
Out of Plumb	100%
Defects	100%

4.1.3 Composite Poles

Composite poles are similar to concrete poles in terms of their increased strength, lifespan, weight, and cost compared to wood poles. The HI for composite poles is calculated by considering a combination of EOL criteria summarized in Table 4-6.

Table 4-6: Composite Pole HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Out of Plumb	2	A,E	4,0	8
Defects	6	A,B,C,E	4,3,2,0	24
			Total score	44

LUI owns 152 composite poles within its service territory. Installation date is known for all the in-service population. Figure 4-6 presents the age distribution for composite poles.

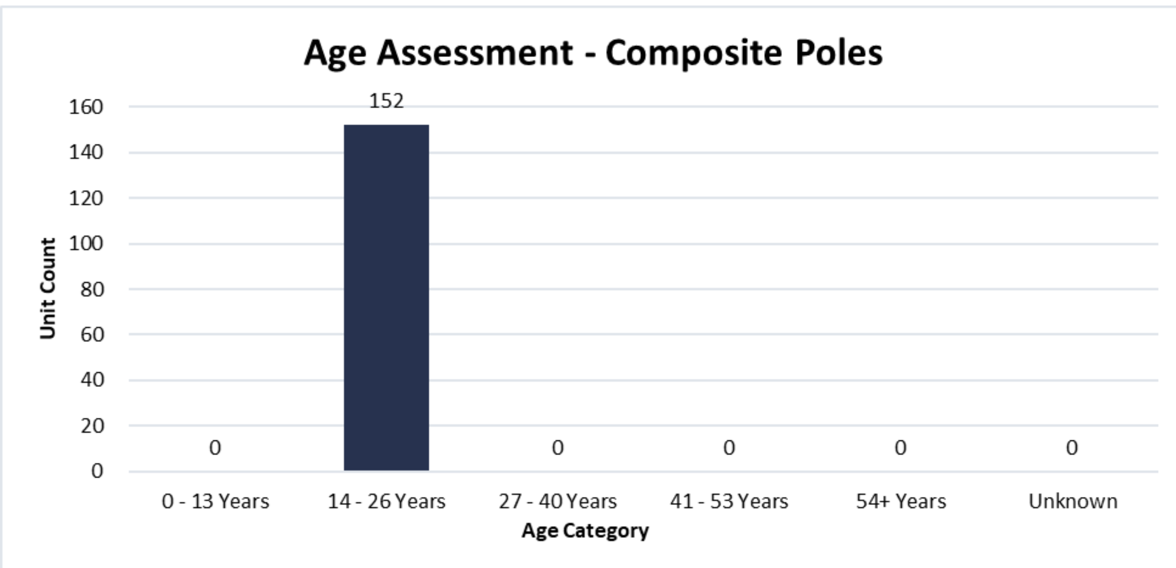


Figure 4-6: Composite Pole Age Demographics

LUI's maintenance and nameplate information was used to calculate the HI. Each Degradation Factor represents a factor critical in determining the asset's condition relative to a potential failure to occur. Aside from service age, Degradation Factors include defects, and evidence of leaning for composite poles. The HI formulation for steel poles does not contain a quantitative measure of remaining strength as found with the wood poles. Hence, it is more dependent on visual inspection of defects. If visual inspection results were left blank for an asset it was assumed that no deficiencies were noted and the asset received a grade of ‘A’.

The overall HI distribution for composite poles is presented in

Figure 4-7. A valid HI score was calculated for all assets. All the poles are in either Very Good or Good condition.

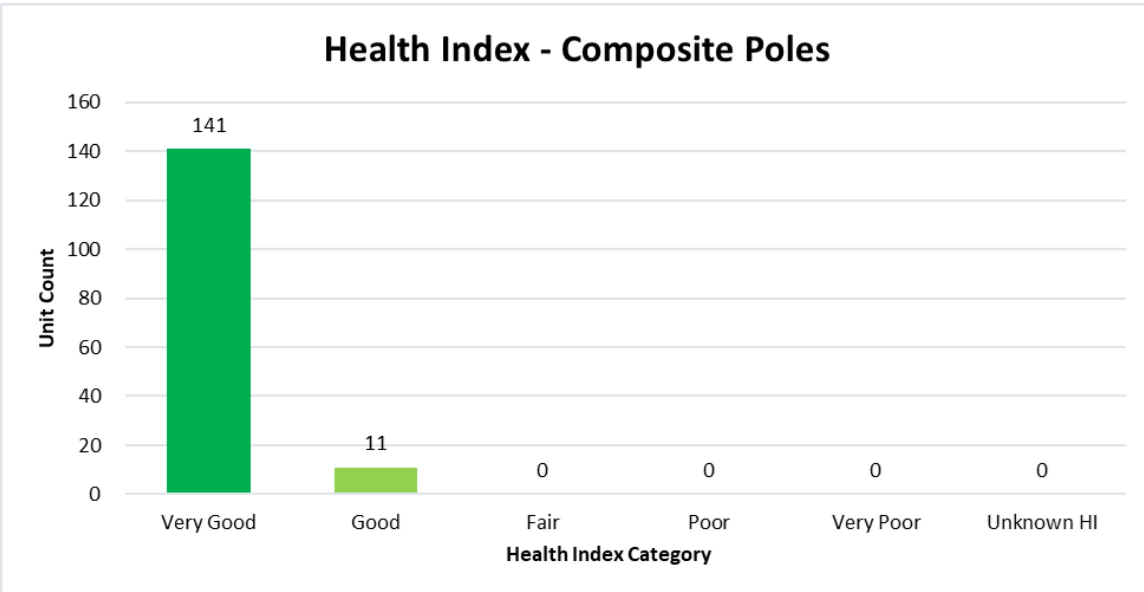


Figure 4-7: Composite Pole HI Results

The average DAI for the asset class is 100%. Table 4-7 presents the DAI of individual Degradation Factors used for the composite poles HI framework.

Table 4-7: Composite Pole Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
Out of Plumb	100%
Defects	100%

4.1.4 OH Conductors

Overhead primary voltage conductors distribute electricity from TS to customers and substations, and from substations to customer premises. They are supported by wood, concrete, or steel poles.

Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age. In addition to age, an undersized conductor presents a greater risk of failure. Undersized conductors carrying large loads can result in sub-optimal system operation due to high line losses and are susceptible to frequent breakdowns.

The HIF for OH Conductors is calculated by considering a combination of EOL criteria summarized in Figure 4-8.

Table 4-8: OH Primary Conductor HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Small Conductor Risk	2	A,E	4,0	8
			Total Score	28

LUI owns approximately 147 km overhead conductor segments within its service territory. Figure 4-8 presents the overall overhead conductor age demographics.

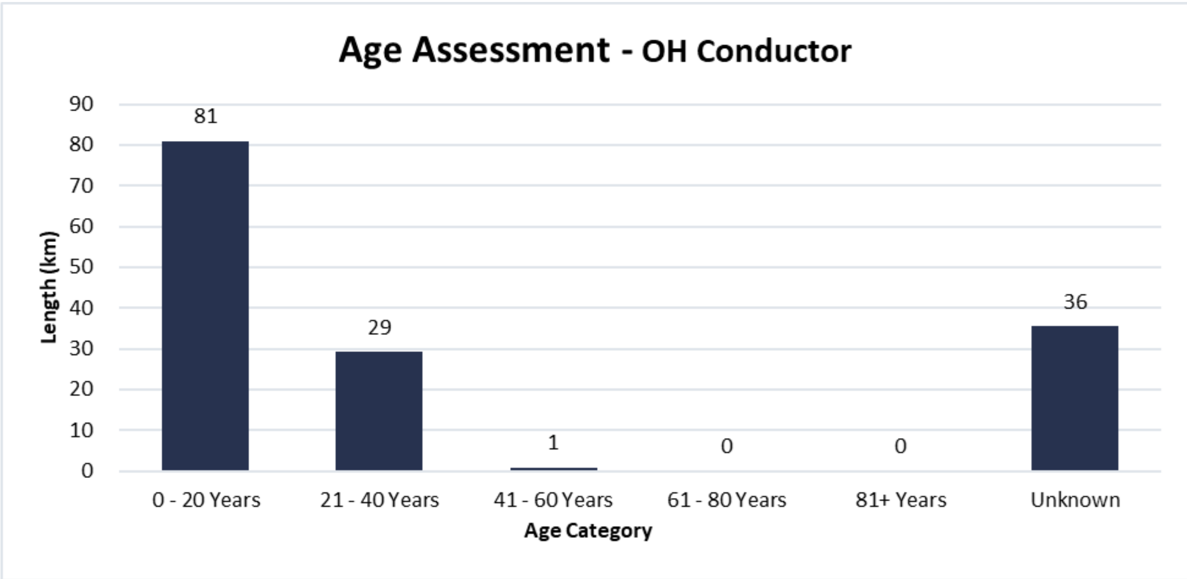


Figure 4-8: Overhead Conductor Age Demographics

LUI's maintenance and operating data was used to calculate the HI for OH conductors. Service age and small conductor risk were used to determine an HI result for overhead conductors. Copper wiring of thinner diameters has a higher electrical resistance, leading to an increased risk of overheating and failing over time.

Figure *4-9* are the HI results for LUI's overhead conductors. Most assets are in Very Good to Good condition.

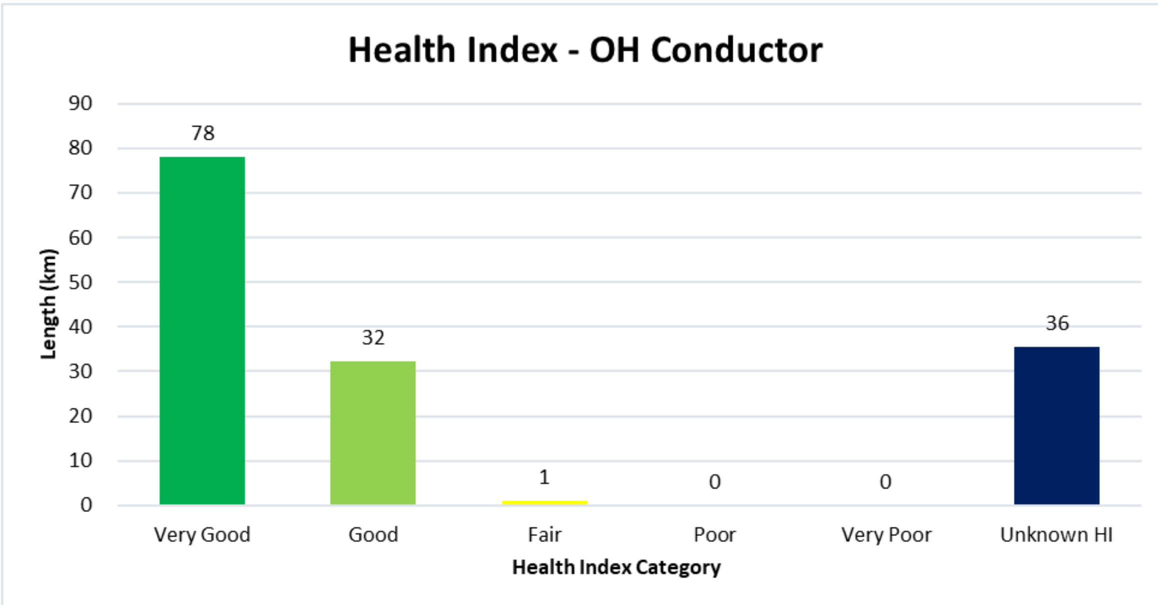


Figure 4-9: Overhead Conductor HI Results

The average DAI for the asset class is 90%. Table 4-9 presents the DAI of individual Degradation Factors used for the overhead primary conductor HI framework.

Table 4-9: Overhead Conductor Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	76%
Small Conductor Risk	100%

4.1.5 Underground Primary Cables

Like overhead conductors, underground primary cables also distribute electricity along the electrical distribution system; however, they are located below ground. Compared to overhead lines, they are much more reliable since they are not exposed to severe weather conditions, tree contacts, or foreign interference.

LUI owns approximately 60 km of UG cables within its service territory. Figure 4-10 presents the age demographics of UG cables.

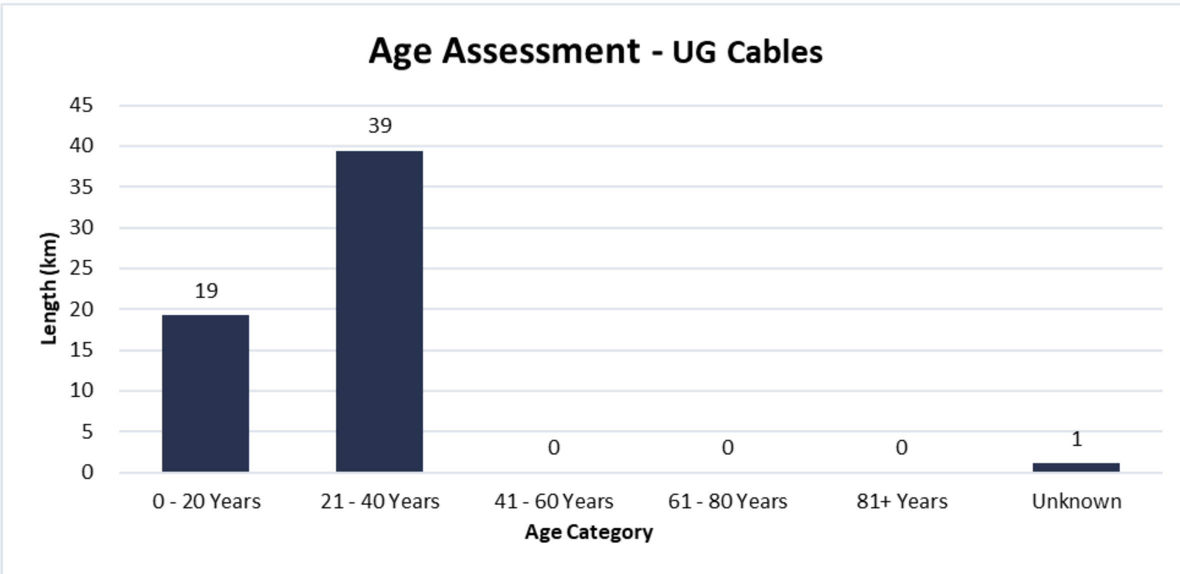


Figure 4-10: Underground Cable Age Demographics

The HI results are unavailable for underground cables due to lack of data availability. Service age was the only available condition parameter, which was extrapolated from the average age of transformers from the same feeder. Table 4-10 presents the DAI of Service Age for LUI's underground cables.

Table 4-10: Underground Cable Data Availability

Degradation Factor	% of Assets with Data
Service Age	98%

4.1.6 Pole-mount Distribution Transformers

Pole-mount distribution transformers are installed on service poles above ground with the primary function to step down distribution voltage to the final secondary voltage for the end-user (customer). The HI for pole-mount transformers is calculated by considering the criteria summarized in Table 4-11.

Table 4-11: Pole-mount Distribution Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	7	A,B,C,D,E	4,3,2,1,0	28
IR Scan	2	A,C,E	4,2,0	8
			Total score	36

LUI owns 618 pole mount transformers within its service territory. Figure 4-11 presents the age distribution for pole-mount transformers.

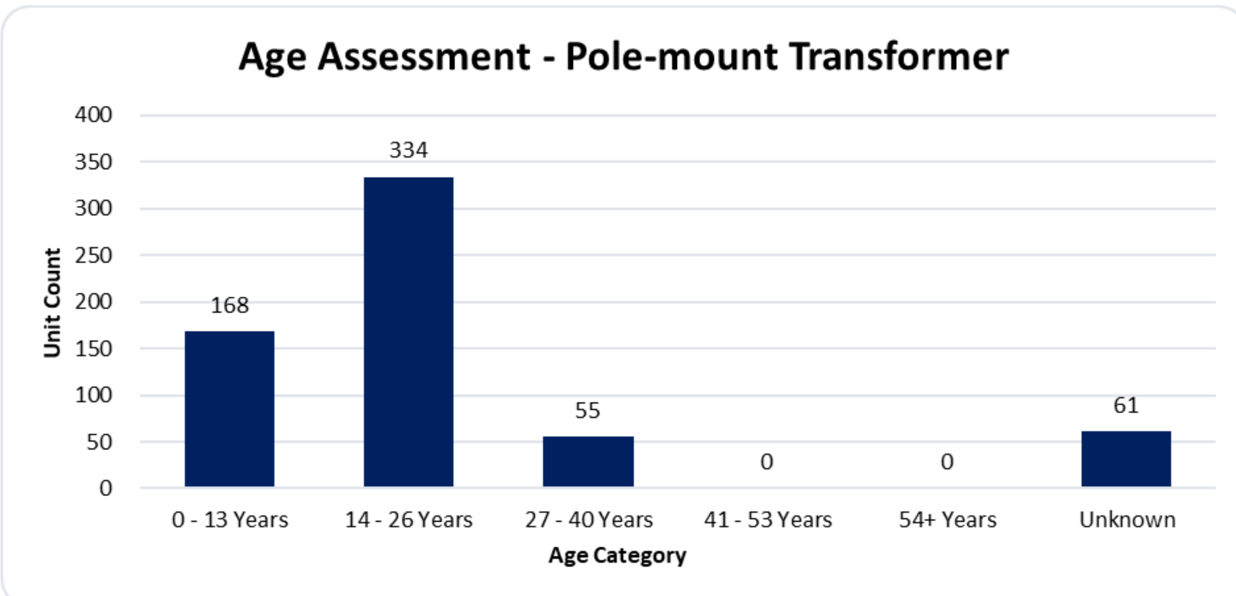


Figure 4-11: Pole-mount Transformer Age Demographics

LUI's service age and IR scan results were used to calculate the HI for pole-mount transformers. IR scanning results provide an important Degradation Factor for condition assessment of the overhead transformers since they identify hotspots (i.e. high temperatures) on the asset. Transformers operating continuously at high temperatures beyond their normal operating state, can cause accelerated degradation of the insulation oil which may lead to premature failure.

A valid HI was calculated for 90% of the overhead transformers. The overall HI distribution is presented in Figure 4-12. Most of the population are in Very Good or Good condition.

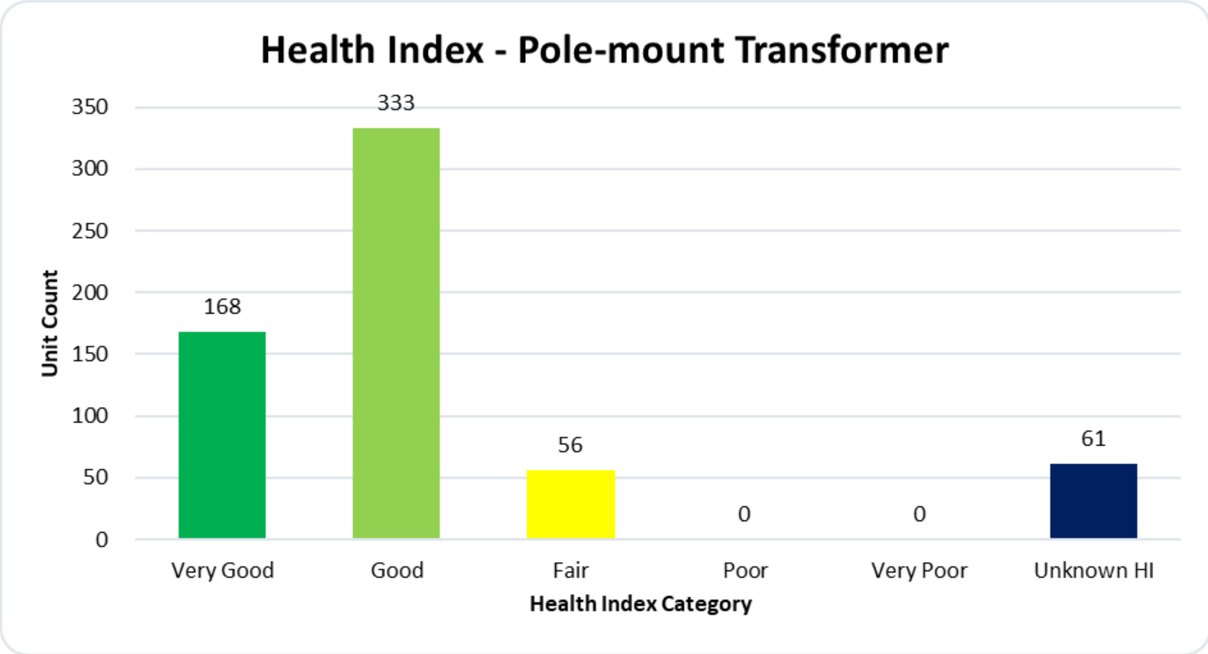


Figure 4-12: Pole-mount Transformer HI Results

The average DAI for this asset class is 92%. Table 4-12 presents the DAI of individual Degradation Factors used for the pole-mount transformer HI framework.

Table 4-12: Pole-mount Transformer Data Availability

Degradation Factor	% of Assets with Data
Service Age	90%
IR Scan	100%

4.1.7 Pad-mount Distribution Transformers

Underground distribution transformers are utilized for similar functionalities as pole-mount transformers. They step down power from the medium-voltage distribution system to the secondary voltage for the customer. They are located below ground or on the ground level. The HI for underground distribution transformers is calculated by considering a combination of EOL criteria summarized in Table 4-13.

Table 4-13: Pad-mount Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	7	A,B,C,D,E	4,3,2,1,0	28
IR Scan	2	A,B,C,D,E	4,3,2,1,0	8
			Total score	36

LUI owns 680 pad mount transformers within its service territory. Unknown installation dates account for approximately 11% of pad-mount transformers. Figure 4-13 presents the age distribution for pad-mount transformers.

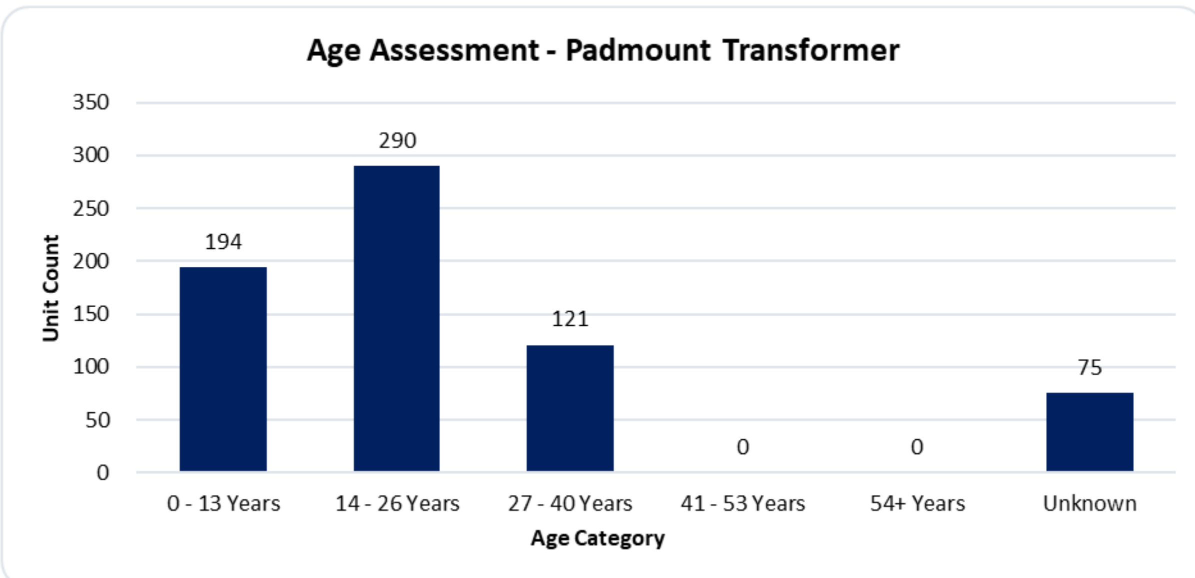


Figure 4-13: Pad-mount Transformer Age Demographics

Like pole-mount transformers, LUI's service age and IR scan results were used to calculate the HI for pad-mount transformers.

A valid HI was calculated for 89% of Pad-mount transformers. Most assets are in Very Good and Good condition, with 18% in Fair condition. HI results are shown in Figure 4-14.

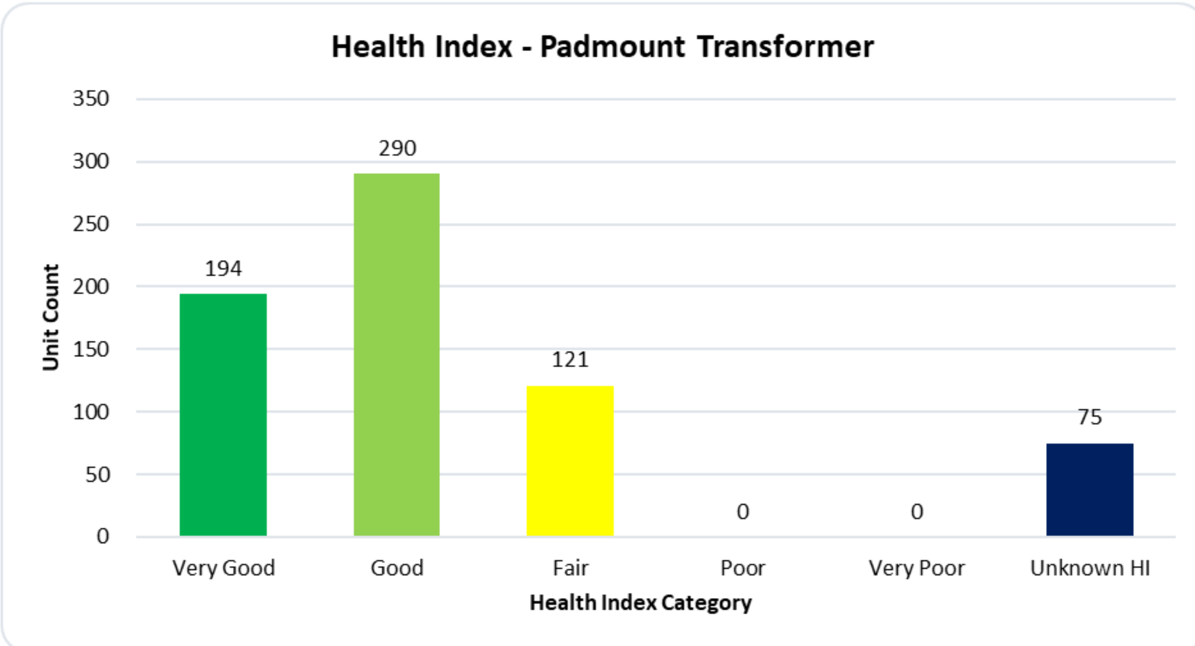


Figure 4-14: Pad-mount Transformer HI Results

The average DAI for pad-mount transformer data is 82%. Table 4-14 presents the DAI of individual Degradation Factors used for the underground distribution transformers HI framework.

Table 4-14: Pad-mount Distribution Transformer Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	89%
IR Scan	100%

4.2 Station Assets

4.2.1 Power Transformers

Power transformers can be considered the most critical asset class. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect tens of thousands of customers. Power transformers in the distribution system are housed within municipal stations. They are used to step down the voltage within the distribution system. Computing the HI of a transformer requires developing EOL criteria for its various components. Table 4-15 summarizes the methodology to generate the HI for power transformers.

Table 4-15: Power Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	12	A,B,C,D,E	4,3,2,1,0	48
DGA	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality	8	A,B,C,D,E	4,3,2,1,0	32
Insulation Resistance (GΩ @ 20°C)	4	A,B,C,D,E	4,3,2,1,0	16
Dissipation Factor	4	A,B,C,D,E	4,3,2,1,0	16
Turns Ratio Test (DEV %)	5	A,B,C,D,E	4,3,2,1,0	20
Winding Resistance (DEV %)	4	A,B,C,D,E	4,3,2,1,0	16
Gaskets and Seals	1	A,C,E	4,2,0	4
Condition of Bushing	5	A,C,E	4,2,0	20
Condition of Gas Pressure Relief	1	A,C,E	4,2,0	4
Control Wiring	1	A,C,E	4,2,0	4
Tap Charger	4	A,C,E	4,2,0	16
Grounding	1	A,C,E	4,2,0	4
Oil Level	3	A,C,E	4,2,0	12
Gauges	1	A,C,E	4,2,0	4
			Total score	256

LUI owns 5 power transformers within its service territory. Installation date is known for all assets. The age distribution of LUI's power transformers is shown in Figure 4-15.

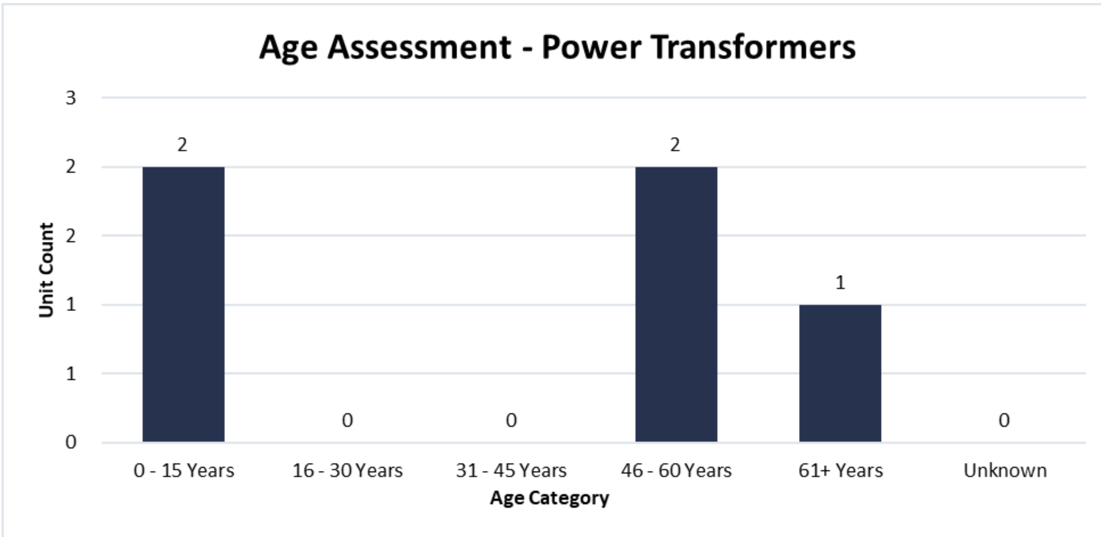


Figure 4-15: Power Transformer Age Distribution

LUI's inspection, testing, and demographics data were used to calculate the HI results for power transformers. The HI score for a transformer is composed of qualitative visual inspection results and quantitative testing results. These measurements include dissolved gas analysis ("DGA"), insulation power factor, oil quality, insulation resistance, turns ratio, and winding resistance. Each of these parameters represents an aspect of a power transformer with a direct impact on the operational health of the asset.

By performing DGA, it is possible to identify the internal faults such as arcing, partial discharge, low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these Degradation Factors strongly indicate progressed degradation of the asset, hence their larger weights. Oil Level and other condition data are collected by visual inspection and serve as indicators of the total health of the asset. Additionally, service age provides a reasonably good measure of the remaining life of the asset and is employed as a Degradation Factor.

The overall HI distribution for power transformers is presented in

Figure 4-16. A valid HI was calculated almost all power transformers. LUI's power transformers with known HI are in Very Good to Fair condition.

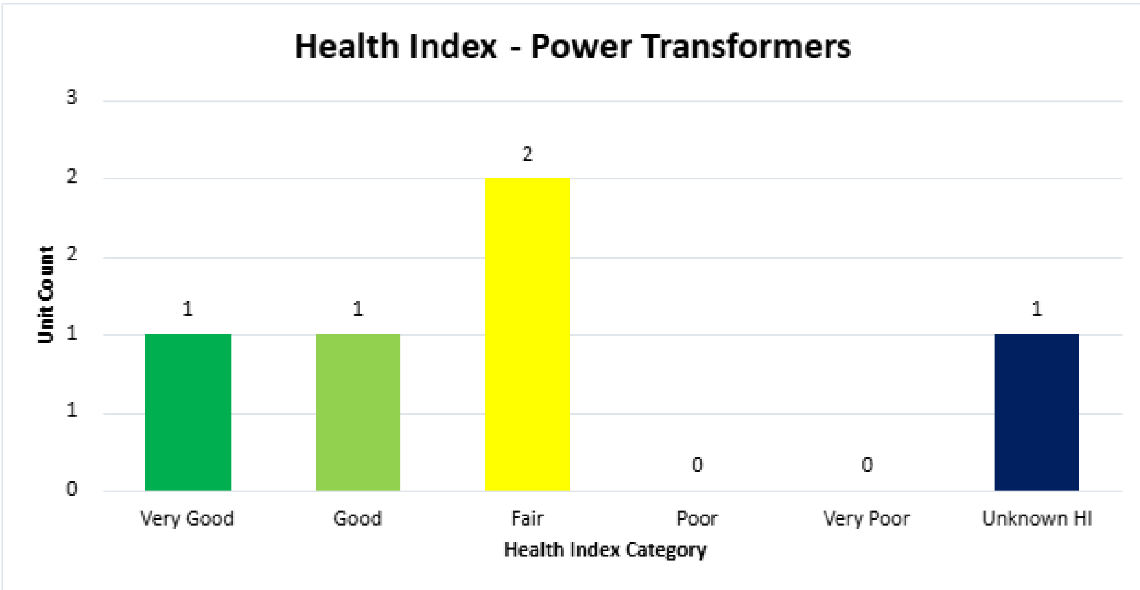


Figure 4-16: Power Transformer HI Results

The average DAI for power transformers is 85%. presents the DAI of individual Degradation Factors used for power transformers respectively.

Table 4-: Power Transformer Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	100%
DGA	40%
Oil Quality	60%
Insulation Resistance (GΩ @ 20°C)	100%
Dissipation Factor	100%
Turns Ratio Test (DEV %)	100%
Winding Resistance (DEV %)	100%
Gaskets and Seals	100%
Condition of Bushing	100%
Condition of Gas Pressure Relief	60%

Degradation Factor	% of Assets with Data
Control Wiring	80%
Tap Charger	100%
Grounding	100%
Oil Level	100%
Gauges	100%

4.2.2 Station Service Transformers

Station service transformers are a part of the auxiliary power supply to the station. They do this by providing power to the station directly from the high voltage line. The HI for service transformers is calculated by considering a combination of EOL criteria summarized in Table 4-16.

Table 4-16: Station Service Transformer HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	3	A,B,C,D,E	4,3,2,1,0	12
Connections Condition	2	A,C,E	4,2,0	8
Bushing Condition	2	A,C,E	4,2,0	8
Grounding Condition	2	A,C,E	4,2,0	8
			Total score	36

LUI owns 2 service transformers. Age demographics are unavailable for this asset class as service age is unknown for all the service transformers.

LUI's visual inspection and testing data were used to calculate HI results for service transformers. Connection, bushing and grounding condition of components are collected by visual inspection and serve as indicators of the total health of the asset.

Figure 4-17 presents the HI results for LUI's service transformers. A valid HI was calculated for all service transformers. LUI's power transformers are in Very Good and Fair condition.

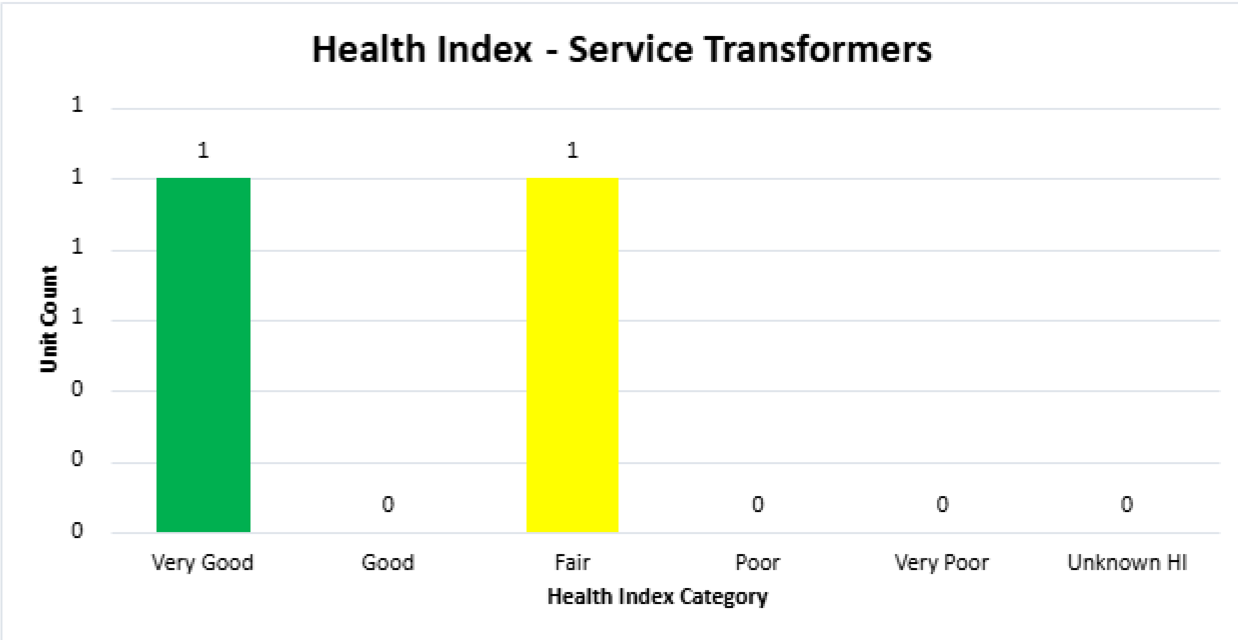


Figure 4-17: Station Service Transformer HI Results

The average DAI for the asset class is 100%. Table 4-17 presents the DAI of individual Degradation Factors used for the Service Transformer HI framework.

Table 4-17: Station Service Transformer Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Insulation Resistance	100%
Connections Condition	100%
Bushing Condition	100%
Grounding Condition	100%

4.2.3 Circuit Breakers

Circuit breakers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. Breakers work with station relays to open, either in a fault situation, as directed by the operations center, or as part of the automation scheme. Computing the HI of a circuit breaker considers EOL criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The HI for substation circuit breakers is calculated by considering a combination of test results, number of operations, and visual inspections as summarized in Table 4-18.

Table 4-18: Circuit Breaker Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Counter Reading	5	A,B,C,D,E	4,3,2,1,0	20
Control & Operating Mechanism Condition	2	A,C,E	4,2,0	8
Contacts Condition	1	A,C,E	4,2,0	4
Foundation, Support, Grounding Condition	3	A,C,E	4,2,0	12
Connections Condition	1	A,C,E	4,2,0	4
Arc Chutes Condition	3	A,C,E	4,2,0	12
Contact Resistance	4	A,B,C,D,E	4,3,2,1,0	16
Insulation Resistance	5	A,B,C,D,E	4,3,2,1,0	20
			Total score	96

LUI owns 11 circuit breakers within its service territory. Age demographics are unavailable for this asset class as installation date is unknown for all assets.

LUI's maintenance and inspection data were used to calculate the HI results for circuit breakers. Counter reading is used as a proxy for service age by comparing against a suggested operation count maximum. Testing, including the contact resistance test and insulation resistance test, are weighted the highest because they are the best indicator of the asset's condition and performance.

The overall HI distribution for the circuit breakers is presented in Figure 4-18. A valid HI was calculated for 73% of circuit breakers. All circuit breakers with known HI are in Very Good condition.

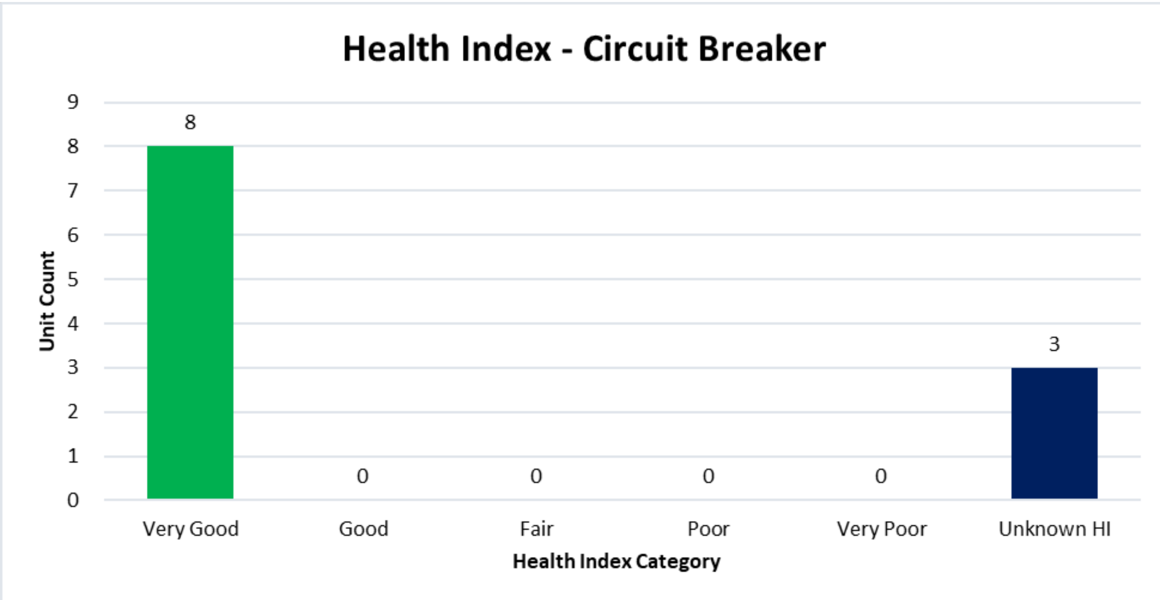


Figure 4-18: Circuit Breaker HI Results

The average DAI for the asset class is 89%. Table 4-19 presents the DAI of individual Degradation Factors used for the circuit breaker HI framework.

Table 4-19: Circuit Breaker Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Counter Reading	100%
Control & Operating Mechanism Condition	73%
Contacts Condition	73%
Foundation, Support, Grounding Condition	73%
Connections Condition	73%
Arc Chutes Condition	64%
Contact Resistance	100%
Insulation Resistance	100%

4.2.4 Reclosers

Reclosers function similar to circuit breakers but often equipped with control unit for single- or multi-shot reclosing of the feeder. The HI for substation reclosures is calculated by considering a combination of test results, and visual inspections as summarized in Table 4-20.

Table 4-20: Reclosers Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Operating Mechanism Condition	2	A,C,E	4,2,0	8
Bushings Condition	2	A,C,E	4,2,0	8
Connections & Terminals Condition	2	A,C,E	4,2,0	8
Grounding Condition	2	A,C,E	4,2,0	8
Oil Leaks	2	A,C,E	4,2,0	8
Contact Resistance	2	A,B,C,D,E	4,3,2,1,0	8
Insulation Resistance	4	A,B,C,D,E	4,3,2,1,0	16
			Total score	64

LUI owns 3 reclosers within its service territory. Age demographics are unavailable for this asset class as installation date is unknown for all assets.

LUI's maintenance and inspection data were used to calculate the HI results for reclosers. Like circuit breakers the contact resistance test and insulation resistance test, are weighted the highest because they are the best indicator of the asset's condition and performance.

The overall HI distribution for the reclosures is presented in Figure 4-19. A valid HI was calculated for all assets. All reclosures are in Very Good condition.

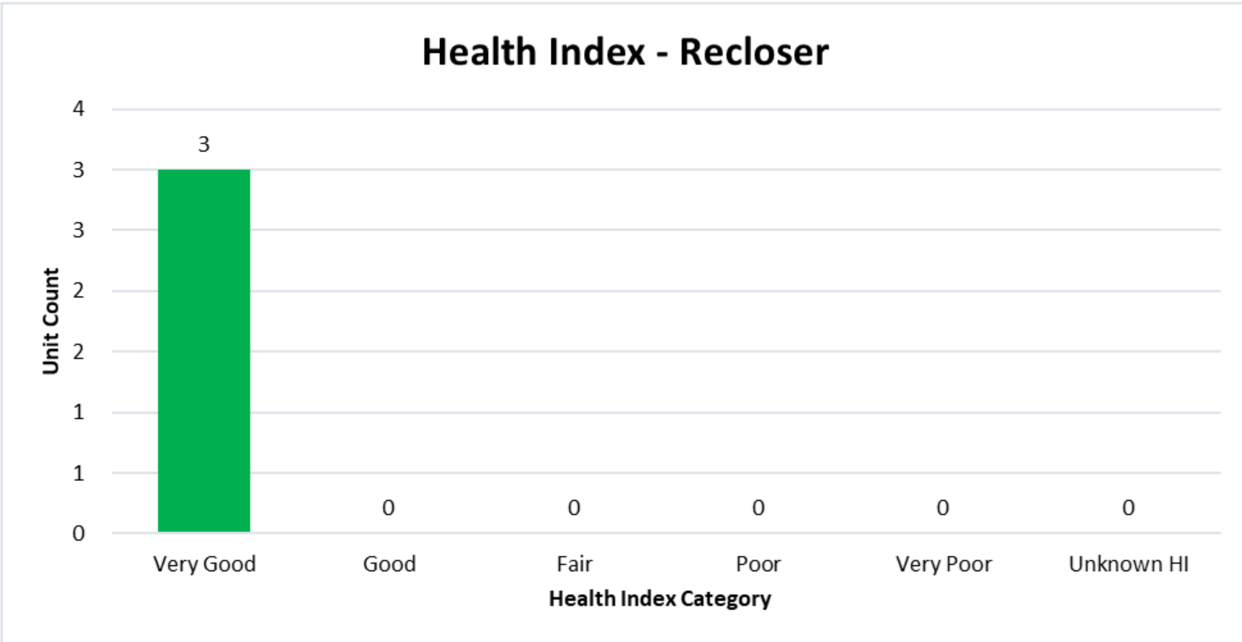


Figure 4-19: Reclosure HI Results

The average DAI for reclosers is 100%. Table 4-24 presents the DAI of individual Degradation Factors used for the circuit breaker HI framework.

Table 4-21: Reclosers Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Operating Mechanism Condition	100%
Bushings Condition	100%
Connections & Terminals Condition	100%
Grounding Condition	100%
Oil Leaks	100%
Contact Resistance	100%
Insulation Resistance	100%

4.2.5 Station Switches

Station switches are utilized as part of the distribution system in order to isolate the stations from the system. This allows LUI to de-energize equipment during maintenance and testing. Table 4-22 summarizes the methodology to generate the HI for station switches.

Table 4-22: Station Switch Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Operating Mechanism	4	A,C,E	4,2,0	16
Contacts	2	A,C,E	4,2,0	8
Connector Condition	3	A,C,E	4,2,0	12
Insulator Condition	3	A,C,E	4,2,0	12
Support Structure Condition	3	A,C,E	4,2,0	12
IR Scan	4	A,C,E	4,2,0	16
Contact Resistance	3	A,B,C,D,E	4,3,2,1,0	12
Insulation Resistance	3	A,B,C,D,E	4,3,2,1,0	12
			Total score	112

LUI owns five station switches within the stations in scope. Installation date is known for 3 station switches. Figure 4-20 presents the age distribution of LUI's station switches.

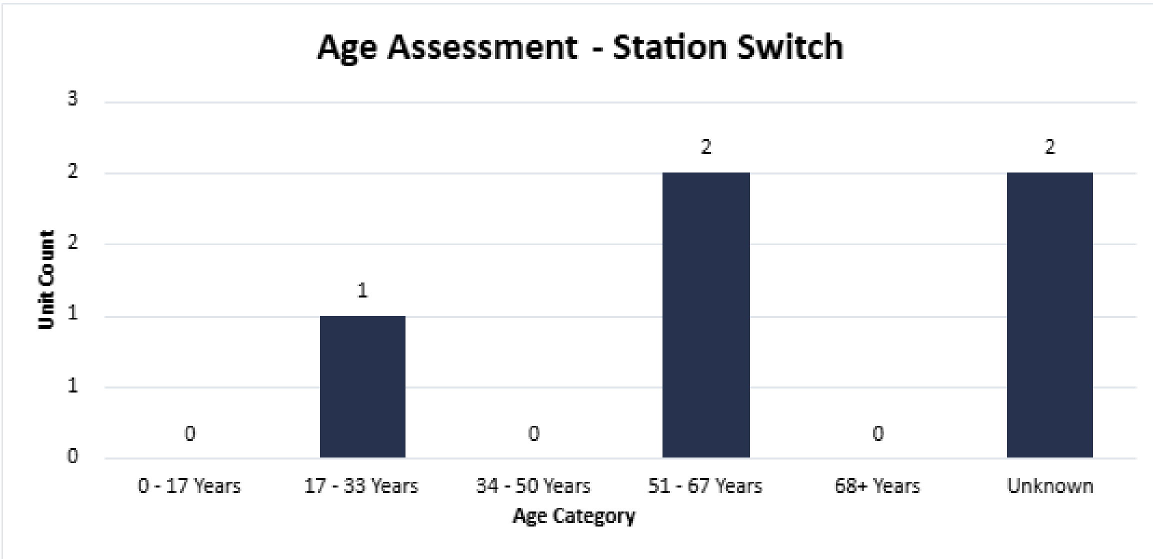


Figure 4-20: Station Switch Age Demographics

LUI's visual inspection, testing, and nameplate data were used to calculate HI results for station switches. The main inputs to the HI formulation are service age and test results. Service age provides a reasonably good measure of the remaining life of the asset and is utilized as a Degradation Factor. Visual inspections of the station switch are also used as a Degradation Factor. Finally, IR scans can detect electrical issues that cannot be determined through visual inspections and are used as Degradation Factors.

The overall HI distribution for the station switches is presented in Figure 4-21. A valid HI was calculated for all of station switches. All station switches are in Good to Fair condition.

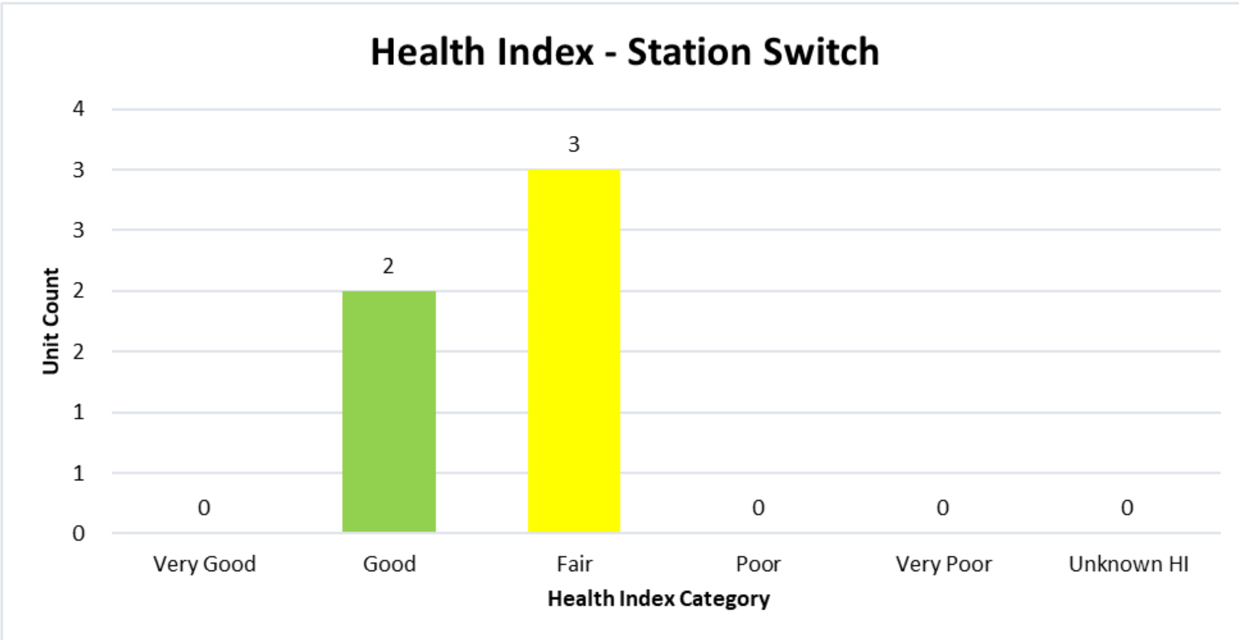


Figure 4-21: Station Switch HI Results

The average DAI for station switches is 96%. presents the DAI of individual Degradation Factors used for the circuit breaker HI framework.

Table 4-23: Station Switches Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	60%
Operating Mechanism	100%
Contacts	100%
Connector Condition	100%
Insulator Condition	100%
Support Structure Condition	100%
IR Scan	100%
Contact Resistance	100%
Insulation Resistance	100%

4.2.6 Station Switchgear

Station switchgears are a part of the municipal station that controls and regulates the current flowing through the distribution system. During a fault, the station switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing.

The HI for station primary switchgears is calculated by considering a combination of EOL criteria summarized in Table 4-24.

Table 4-24: Station Switchgear HI Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Enclosure Condition	2	A,C,E	4,2,0	8
Control & Operating Mechanism Condition	2	A,C,E	4,2,0	8
Overall Condition	2	A,C,E	4,2,0	8
Insulation Resistance	5	A,B,C,D,E	4,3,2,1,0	20
			Total score	52

LUI owns 3 switchgears within its service territory. Installation date is known for 2 of the 3 assets. Figure 4-22 presents the age distribution for station switchgears.

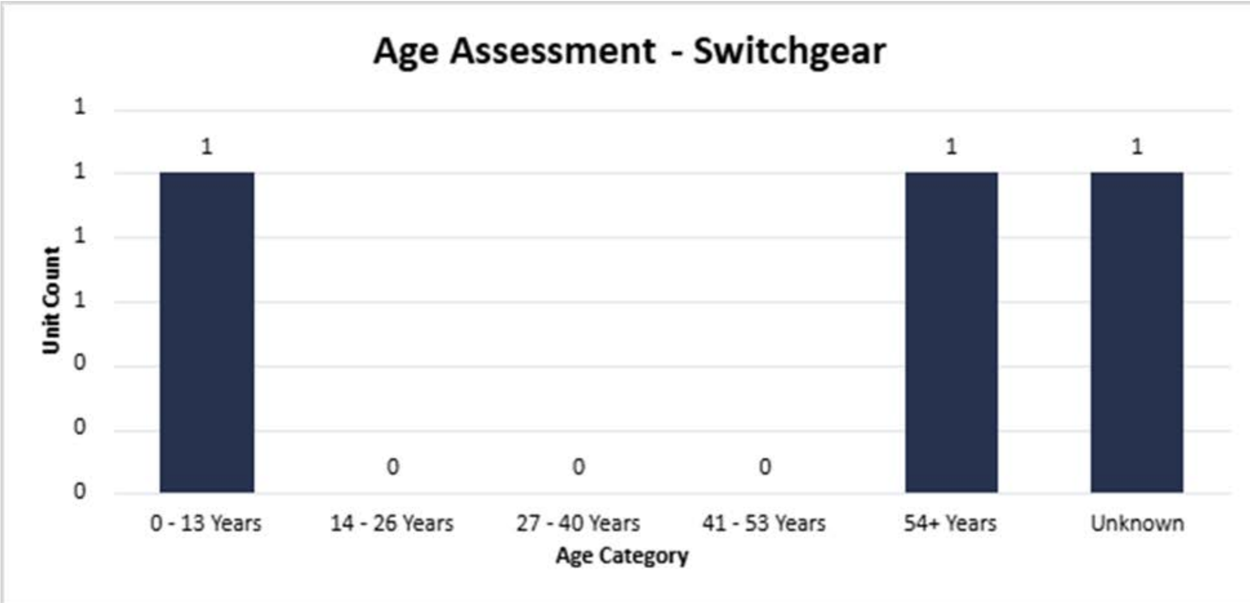


Figure 4-22: Primary Switchgear Age Demographics

LUI maintenance and nameplate data were used to calculate the HI for station switchgears. A valid HI was calculated for 66% off switchgears. Visual inspections and electrical test records of the primary switchgear are used as a Degradation Factor. The insulation resistance is weighed the highest as it is the best indicator of the asset's condition and performance. The visual inspections include enclosure condition, operating mechanism condition as well as the following parameters considered under overall condition: Signage, Lightning Arrestor Condition, Grounding, Heater Condition, Presence of Moisture, and Paint Condition.

The overall HI distribution for the switchgear is presented in Figure 4-23. All switchgears with known HI are in Very Good or Good condition.

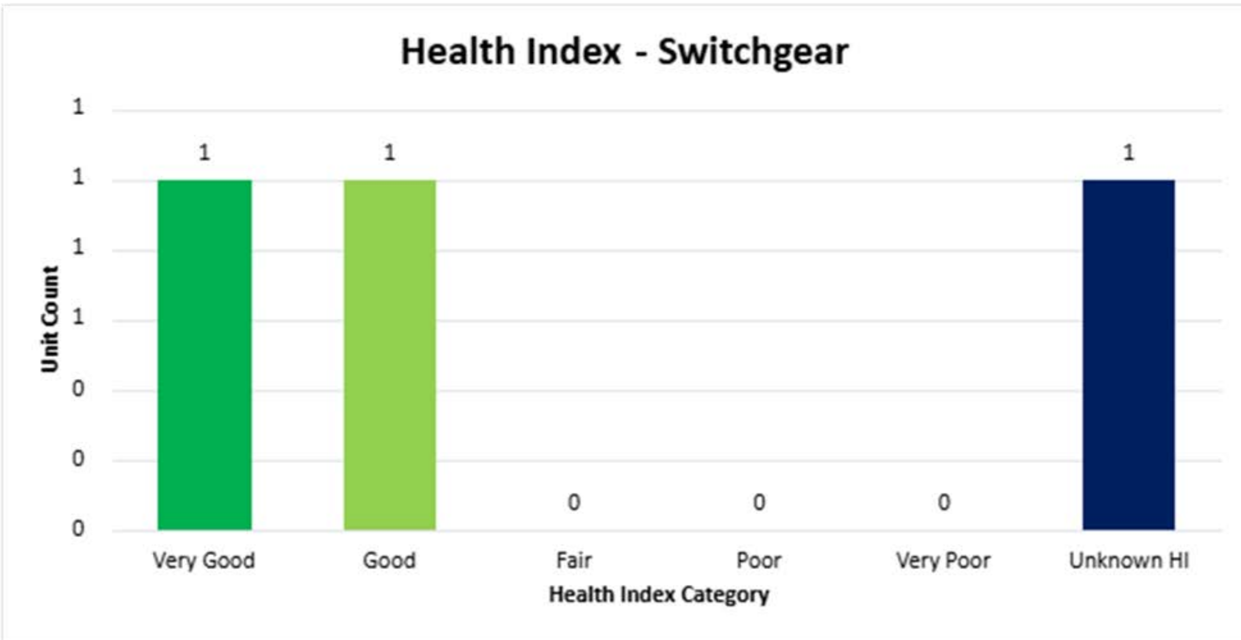


Figure 4-23: Primary Switchgear HI Results

The average DAI for station switchgears is 82%. Table 4-25 presents the DAI of individual Degradation Factors used for the switchgear HI framework.

Table 4-25: Station Switchgear Degradation Factor Data Availability

Degradation Factor	% of Assets with Data
Service Age	67%
Enclosure Condition	100%
Control & Operating Mechanism Condition	100%
Overall Condition	100%
Insulation Resistance	67%

4.2.7 Station Facilities

The integrity of station building, fence, gate, and yard contribute the safety of the station and the performance of the assets therein. The HI for station facilities is calculated by using the visual inspection results from monthly station inspections. Table 4-26 highlights the HI algorithm for buildings.

Table 4-26: Station Building Health Index Algorithm

Degradation Factor	Weight	Ranking	Numerical Grade	Max Score
Building - Signage	1	A,E	4,0	4
Building - HVAC	2	A,E	4,0	8
Fence - Condition	3	A,E	4,0	12
Fence - Tampering	3	A,E	4,0	12
Fence - Coverage	3	A,E	4,0	12
Fence - Signage	1	A,E	4,0	4
Fence - Grounding	2	A,E	4,0	8
Fence - Gate Operational	3	A,E	4,0	12
Yard - Condition	1	A,E	4,0	4
Yard - Vegetation	1	A,E	4,0	4
Yard - Debris	1	A,E	4,0	4
			Total score	84

LUI owns 5 station buildings within its service territory. Age demographics are unavailable for this asset class as service age is unknown for all station buildings.

LUI's visual inspection data for station buildings, fences, and yard were used to calculate the HI results for station facilities.

Figure 4-24 presents the HI result for station facilities. A valid HI was calculated for all station buildings. All station facilities are in Very Good condition.

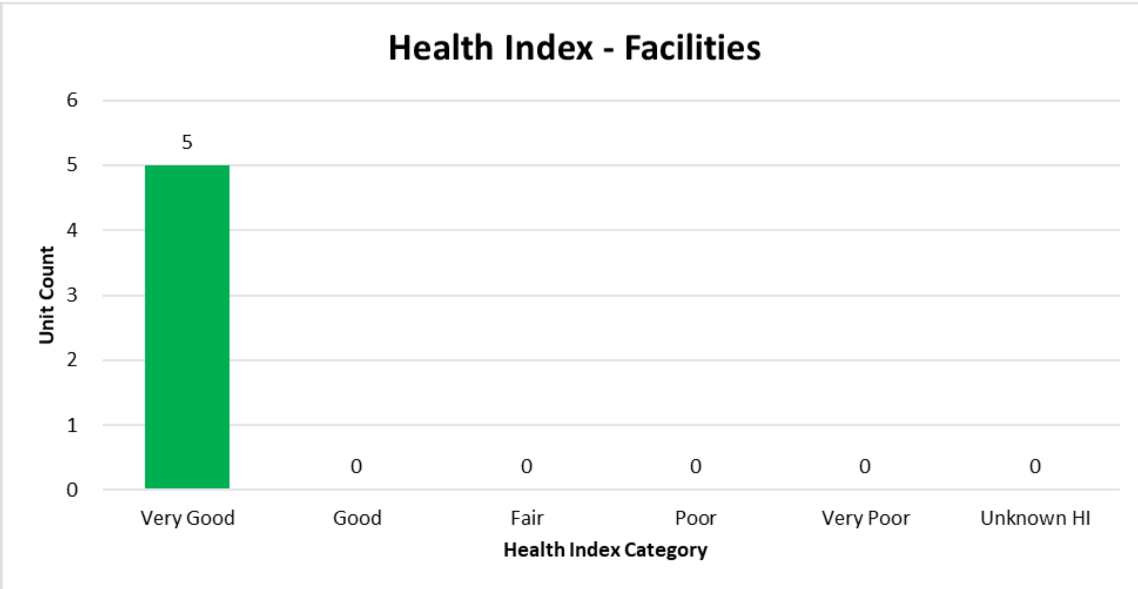


Figure 4-24: Station Building HI Results

The average DAI for station facilities is 100%. Table 4-27 presents the DAI of individual Degradation Factors used for the station facilities HI framework.

Table 4-27: Station Switch Degradation Factors Data Availability

Degradation Factor	% of Assets with Data
Building - Signage	100%
Building - HVAC	100%
Fence - Condition	100%
Fence - Tampering	100%
Fence - Coverage	100%
Fence - Signage	100%
Fence - Grounding	100%
Fence - Gate Operational	100%
Yard - Condition	100%
Yard - Vegetation	100%
Yard - Debris	100%

5. Recommendations

A complete ACA framework for LUI represents an integral component of its broader asset management framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows LUI to make informed investment decisions. There are further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

This section breaks down BBA's recommendations into the following categories:

- HI Improvement;
- Data Availability Improvements; and
- Additional Asset Classes.

5.1 Health Index Improvements

The following set of recommendations target additional Degradation Factors that can be incorporated for each asset class to improve the HI formulation and provide LUI with additional data to refine its asset condition calculations. The recommendations are based on the "Ideal" ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted. The priority of each recommendation depends on the relative weight of the Degradation Factor that it addresses.

5.1.1 Wood Poles

HI results for wood poles are derived using visual inspection and age demographic data, however the addition of testing data such as remaining strength could improve the accuracy of the HI scores as it is an informative end-of-life criterion. It should be noted that data assumptions were made to account for missing visual inspection data. BBA encourages LUI to update the visual inspection data for this asset.

Condition parameters which may benefit from additional data in future ACAs include:

- Remaining Strength Test.

5.1.2 Concrete Poles

Condition parameters currently collected for LUI's concrete poles provide a comprehensive HI formulation. It should be noted that data assumptions were made to account for missing visual inspection data. BBA encourages LUI to update the visual inspection data for this asset.

5.1.3 Composite Poles

Condition parameters currently collected for LUI's concrete poles provide a comprehensive HI formulation. It should be noted that data assumptions were made to account for missing visual inspection data. BBA encourages LUI to update the visual inspection data for this asset.

5.1.4 OH Conductor

Condition parameters currently collected for LUI's OH conductors provide a comprehensive HI formulation. If available, visual inspection results are another condition parameter that can be included in the HI formulation.

Condition parameters which may benefit from additional data in future ACAs include:

- Visual Inspection Results.

5.1.5 UG Primary Cables

A valid HI formulation was not available for UG cables since service age service age was the only data parameter available. Furthermore, the data availability for service age was very low at 2%.

BBA recommends the following additional condition parameters for future ACAs:

- Loading History;
- Failure Rates; and

- Number of Splices.

5.1.6 Pole-mount Transformers

Service age and IR scans are the degradation factors used to formulate HI results for pole-mount transformers. BBA recommends the addition of visual inspection results or loading history to enable a more comprehensive HIF for future ACAs.

Condition parameters which may benefit from additional data in future ACAs include:

- Loading History; and
- Visual Inspection Results.

5.1.7 Pad-mount Transformers

The condition parameters used to formulate the HI results for pad-mount transformers are service age and IR scans. BBA recommends the addition of visual inspection results or loading history to enable a more comprehensive HIF for future ACAs.

Condition parameters which may benefit from additional data in future ACAs include:

- Loading History; and
- Visual Inspection Results.

5.1.8 Station Power Transformers

LUI currently owns 5 power transformers. 3 power transformers are missing DGA test results, and 2 power transformers are missing oil quality test results. As the DGA and Oil quality tests are major components in the HIF for power transformers, BBA recommends LUI prioritize the collection of these test results.

Condition parameters which may benefit from additional data in future ACAs include:

- Oil Leaks;
- Loading History (%); and
- IR Scan.

5.1.9 Station Service Transformers

Condition parameters used for the HI formulation of LUI's service transformers are derived from visual inspection and testing results. BBA recommends the addition of service age or IR Scan results to enable a more comprehensive HIF for future ACAs.

Condition parameters which may benefit from additional data in future ACAs include:

- Service Age; and
- IR Scan.

5.1.10 Circuit Breakers

Condition parameters currently collected for LUI's circuit breakers provide a comprehensive HI formulation. BBA recommends incorporating breaker timing test and IR scan results into future ACAs. Service age can also be added to the HI formulation to compliment operation counter reading.

Condition parameters which may benefit from additional data in future ACAs include:

- Service Age;
- IR Scan; and
- Breaker Timing test.

5.1.11 Reclosers

Condition parameters currently collected for LUI's reclosers provide a comprehensive HI formulation.

Condition parameters which may benefit from additional data in future ACAs include:

- Service Age;
- Counter readings; and
- IR Scan.

5.1.12 Station Switches

Condition parameters currently collected for LUI's circuit breakers provide a comprehensive HI formulation. Condition of switch/disconnect blades can be considered as an additional visual inspection parameter.

Condition parameters which may benefit from additional data in future ACAs include:

- Condition of Switch/Disconnect Blades.

5.1.13 Station Facilities

Visual inspection data for station buildings can be incorporated into the HI formulation for station facilities. Visual inspection data parameters BBA recommends LUI collect are listed below. Service Age for Station buildings can also be integrated into the existing HIF.

BBA recommends considering the following condition parameters for future ACAs:

- Service Age – Station Buildings
- Overall Condition – Station Buidlings
    - Floors/Foundation Condition;
    - Wall Condition;
    - Doors/Windows/Louvres Condition;
    - Roof Condition; and
    - Lighting/Power Condition.

5.2 Data Availability

Data availability is critical in being able to produce prudent, accurate and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA study, each asset class included a breakdown of data available for each Degradation Factor collected. For Degradation Factors with data availability below 60%, BBA recommends that LUI continue collecting the information related to these data points to reach the 60% data availability threshold.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the Degradation Factors used in the HI formulation. As part of future improvement opportunities, it is recommended that LUI continue capturing asset data for Degradation Factors that are currently available for a small proportion of the asset population, such that valid Health Indices can be produced across the population. It is expected that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

BBA noticed that some Degradation Factors recorded by LUI vary in the detail with respect to the grading scheme. For example, most inspection results followed a three-tier (OK, FAIR, and POOR) or four-tier grading scheme (None, Slight, Moderate, Extensive). BBA recommends for LUI to evaluate options of changing some Degradation Factors recorded to a five-level grade (e.g., from Very Good to Very Poor), as doing so can provide more defined segregation between assets that need immediate attention and those that can still be in-service with normal or no maintenance in the short-term.

Keeping records of asset condition is good practice, as it may assist in planning and assessing the quality of assets being replaced in-service. BBA recommends collecting and keeping condition records consistent for all assets inspected. BBA recommends that LUI tracks all contractor assessments through a central system, such as GIS, as part of their process improvements between Asset Management and GIS. This will help LUI in both standardizing inspection results and quickly identifying and flagging issues within the system. Obtaining and organizing more comprehensive condition data records would establish a stronger baseline of the asset health indices and more robust, multi-parameter, HI formulations can be used that are in-line with standardized practice in the industry.

Finally, it is recommended that LUI moves towards a Risk-Based Framework for investment planning in the future.

5.2.1 Additional Asset Classes

BBA recommends the following additional asset classes to be included for future ACAs:

- Distribution Switchgears
- OH Switches

- Station Battery Banks/Chargers
- Station Cables

6. Conclusions

Most assets of LUII's asset classes with valid HI results are in Very Good to Fair condition. This can indicate LUI has taken the necessary steps to manage its asset health and performance for the benefit of its customers. It should be noted that some asset classes like station switchgears and circuit breakers have high percentages of assets with Unknown HI.

BBA recommends that LUI continue their work to mitigate the gaps in their existing data gaps to expand future ACA. This would result in the immediate benefits of having more degradation parameters that can be assigned actual grades, expanding the sample size of valid HI and capturing all possible degradation of the evaluated assets.

LUI should work to expand the types of data captured as to best represent each assets degradation to the greatest accuracy. LUI's testing, inspection, and maintenance programs are well-positioned to continue to capture this information using processes and technologies in place at their facility.

Lastly, LUI should consider including the additional asset classes listed in Section 5.2.1 to attain a more holistic understanding of system-wide asset health.

This concludes BBA's report on the condition assessment performed for LUI. We thank LUI's staff and management for the opportunity to participate in this complex study, and for their ongoing support throughout its development.

Appendix A: Condition Parameter Grading Tables

A.1 Wood Poles

Table A-1: Criteria for Wood Pole Service Age

Condition Rating	Corresponding Condition
A	0-15 years
B	16-30 years
C	31-45 years
D	46-60 years
E	61+ years

Table A-2: Criteria for Wood Pole treatment

Condition Rating	Corresponding Condition
A	CCA, Creosote full, Penta full
C	Creosote butt, Penta butt
D	Salt
E	Untreated

Table A-3: Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	None
B	Slight
C	Moderate
E	Extensive, Crack to GL

Table A-4: Criteria for Hardware Condition

Condition Rating	Corresponding Condition
A	None
B	Slack guy wire, Obstruction at GL, Guy guard required
C	Ground guard required
E	Broken ground wire, Wire touching tree

Table A-5: Criteria for Internal Decay

Condition Rating	Corresponding Condition
A	None
B	Slight
C	Moderate
E	Extensive, Pocket

Table A-6: Criteria for Out of Plumb

Condition Rating	Corresponding Condition
A	No
E	Yes

A.2 Concrete Poles

Table A-7: Criteria for Concrete Pole Service Age

Condition Rating	Corresponding Condition
A	0-20 years
B	21-40 years
C	41-60 years
D	61-80 years
E	81+ years

Table A-8: Criteria for Visual Inspection

Condition Rating	Corresponding Condition
A	None
B	Slight
C	Moderate
E	Extensive

Table A-9: Criteria for Out of Plumb

Condition Rating	Corresponding Condition
A	No
E	Yes

A.3 Composite Poles

Table A-10: Criteria for Composite Pole Service Age

Condition Rating	Corresponding Condition
A	0-13 years
B	14-26 years
C	27-40 years
D	41-53 years
E	54+ years

Table A-11: Criteria for Defects

Condition Rating	Corresponding Condition
A	None
B	Slight
C	Moderate
E	Extensive

Table A-12: Criteria for Out of Plumb

Condition Rating	Corresponding Condition
A	No
E	Yes, Leaning

A.4 OH Primary Conductor

Table A-13: Criteria for OH Primary Conductors Service Age

Condition Rating	Corresponding Condition
A	0-13 years
B	14-26 years
C	27-40 years
D	41-53 years
E	54+ years

Table A-14: Criteria for Small Conductor Risk

Condition Rating	Corresponding Condition
A	No signs of any defects on the composite pole due to vandalism, vehicular accidents, electrical burns, or cracking
B	Slight: Signs of minor defects on the composite pole due to vandalism, vehicular accidents, electrical burns, or cracking
C	Moderate: Signs of significant defects on the composite pole due to vandalism, vehicular accidents, electrical burns, or cracking
E	Extensive: Signs of very serious defects on the composite pole due to vandalism, vehicular accidents, electrical burns, or cracking

A.4 Pole-mount Transformer

Table A-15: Criteria for Pole-mount Transformer Service Age

Condition Rating	Corresponding Condition
A	0-13 years
B	14-26 years
C	27-40 years
D	41-53 years
E	54+ years

Table A-16: Criteria for IR Scans

Condition Rating	Corresponding Condition
A	No hot spots detected
C	Low Priority: Noticeable hot spots detected, but they do not jeopardize safe on-going operation.
E	Medium/High Priority: Very serious hot spots detected

A.5 Pad-Mount Transformer

Table A-17: Criteria for Pad-Mount Transformer Service Age

Condition Rating	Corresponding Condition
A	0-13 years
B	14-26 years
C	27-40 years
D	41-53 years
E	54+ years

Table A-18: Criteria for IR Scans

Condition Rating	Corresponding Condition
A	No hot spots detected
C	Low Priority: Minor hot spots/hot spots on connections detected
E	Medium/High Priority: Major hot spots detected

A.6 Power Transformer

Table A-19: Criteria for PTX Service Age

Condition Rating	Corresponding Condition
A	0-15 years
B	16-30 years
C	31-45 years
D	46-60 years
E	61+ years

Table A-20: Criteria for DGA Results

Condition Rating	Corresponding Condition
A	All parameters within acceptable limits
B	1 parameter does not meet acceptability limits
C	2 parameters do not meet acceptability limits
D	3 parameters do not meet acceptability limits
E	4 or more parameters do not meet acceptability limits

Table A-21: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class U ≤ 69 kV	Grade
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table A-22: Criteria for Insulation Resistance

Condition Rating	Corresponding Condition
A	400% + Min Resistance
B	(300%-400%) Min Resistance
C	(200%-300%) Min Resistance
D	(100%-200%) Min Resistance
E	<100% Min Resistance

Table A-23: Criteria for Dissipation Factor

Condition Rating	Corresponding Condition
A	0-0.49
B	0.5-0.99
C	1-1.49

D	1.5-1.99
E	2+

Table A-24: Criteria for Turns Test Ratio

Condition Rating	Corresponding Condition
A	Max Deviation: 0-0.09%
B	0.10-0.29%
C	0.03-0.39%
D	0.40-0.49%
E	≥ 0.5%

Table A-25: Criteria for Winding Resistance Test

Condition Rating	Corresponding Condition
A	0-0.49%
B	0.50-2.49%
C	2.5-3.99%
D	4.0-4.99%
E	≥ 5%

Table A-26: Criteria for PTX Visual Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

A.7 Service Transformer

See table Table A-22 for Insulation Resistance criteria.

Table A-27: Criteria for Service TX Visual Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

A.8 Circuit Breaker

Table A-28: Criteria for Counter Reading

Condition Rating	Corresponding Condition
A	0-1,000 operations
B	1,000-3000 operations
C	3,000-5,000 operations
D	5,000-10,000 operations
E	10,000+ operations

Table A-29: Criteria for Circuit Breaker Visual Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Table A-30: Criteria for Contact Resistance

Condition Rating	Corresponding Condition
A	Largest Deviation between Poles: (0-10]%
B	(10-25]%
C	(25-40]%

D	(40-50]%
E	>50%

See table Table A-22 for Insulation Resistance criteria.

A.9 Reclosers

Table A-31: Criteria for Reclosers Visual Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

See Table A-22 for Insulation Resistance criteria.

See

Table A-30 for Contact Resistance criteria.

A.10 Station Switches

Table A-32: Criteria for Station Switch Service Age

Condition Rating	Corresponding Condition
A	0-17 years
B	18-33 years
C	34-50 years
D	51-67 years
E	68+ years

Table A-33: Criteria for Station Switch Visual Condition

Condition Rating	Corresponding Condition

A	OK
C	FAIR
E	POOR

Table A-34: Criteria for IR Scan

Condition Rating	Corresponding Condition
A	No Problems Noted
C	Low Priority
D	Medium Priority
E	High Priority

See Table A-22 for Insulation Resistance criteria.

See

Table A-30 for Contact Resistance criteria.

A.11 Station Facilities

Table A-35: Station Building/Fence/Yard Inspection

Condition Rating	Corresponding Condition
A	Yes
E	No

APPENDIX - J
Climate Vulnerability and System Hardening (VASH) Sample Study

Summary

LUI completed its Climate Vulnerability Assessment and System Hardening (VASH) in accordance with the Ontario Energy Board's (OEB) Chapter 5 Filing Requirements (Section 5.3.6), applying the OEB's Vulnerability Assessment (VA) and Benefit-Cost Analysis (BCA) Toolkits under the Generic Option.

Climate Peril and Scope

Wind loading on overhead distribution poles was selected as the primary climate peril for the 2027–2031 DSP period. This reflects the predominance of overhead construction on LUI's system, historical outage performance driven by wind-related events, and the availability of detailed pole inventory, inspection, and framing data. The assessment focused on overhead pole assets across LUI's service territory, with initial project evaluation conducted on a representative feeder segment in Cobourg.

Severity Threshold Development

Severity thresholds were developed using representative pole configurations derived from field inspection data, Asset Condition Assessment (ACA) results, and typical loading conditions. Structural capacity was determined using non-linear pole loading analysis, with wind speeds incrementally increased until the governing component reached its failure limit. A planning-level severity threshold was defined as 75% of modelled structural capacity account for field variability, joint-use loading uncertainty, and configuration deviations. The pole framing assumptions are shown in Table J-1.

Table J-1: Pole Framing and Assumptions

Pole Class	Framing Configuration	Modeled Structural Capacity	Planning Severity Threshold
1	2 primary circuits of 556kcmil + 2 primary circuits of 336kcmil + natural + communication cables	105km/h	79
2	2 primary circuits of 556kcmil + 1 primary circuit of 336kcmil + neutral + communication cables	105km/h	79
3	1 primary circuit of 556kcmil + 1 primary circuit of 336kcmil + 1 secondary quad circuit + 1 secondary triplex circuit + neutral + communication cables	100km/h	75
4	1 primary circuit of 336kcmil + 1 secondary quad + 1 secondary triplex + neutral + communication cables	106km/h	80
5	1 secondary quad circuit + 1 secondary triplex circuits + communications cables	125km/h	94
6	1 secondary triplex circuit + communication cables	135km/h	101

Vulnerability Assessment and Project Selection

Vulnerability Assessment (VA) results were evaluated alongside ACA data, historical outage performance, and Worst Performing Feeder analysis. This integrated assessment identified concentrations of higher-risk assets within targeted feeder segments (Figure J-1). Based on this assessment, a pilot system hardening project was selected which aligned with VASH outcomes, involving the early replacement of selected Class 2 and Class 3 poles along Elgin Street West.

Figure J-1: Class-Level Wind Vulnerability Screening (Cobourg)

Location	Cobourg

	Low	Medium	High	Very High
Annual Probability Bin	0.02	0.10	0.20	>0.2

Asset Vulnerability Heatmap

Asset Class	Sub Class	2025	2030	2035	2040	2045	2040	2055	2060	2065	2070	2075	2080	2085	2090	2095	2100
Pole	Class 6	0.019	0.019	0.019	0.020	0.020	0.022	0.022	0.024	0.026	0.027	0.026	0.026	0.027	0.029	0.029	0.029
Pole	Class 5	0.047	0.046	0.046	0.048	0.049	0.052	0.053	0.055	0.057	0.059	0.058	0.058	0.059	0.061	0.061	0.061
Pole	Class 4	0.120	0.120	0.119	0.120	0.121	0.122	0.122	0.123	0.124	0.125	0.124	0.124	0.125	0.125	0.125	0.125
Pole	Class 3	0.137	0.137	0.136	0.137	0.138	0.139	0.139	0.140	0.141	0.142	0.142	0.141	0.142	0.143	0.143	0.143
Pole	Class 2	0.123	0.123	0.123	0.123	0.124	0.125	0.125	0.126	0.127	0.128	0.128	0.127	0.128	0.129	0.129	0.129
Pole	Class 1	0.123	0.123	0.123	0.123	0.124	0.125	0.125	0.126	0.127	0.128	0.128	0.127	0.128	0.129	0.129	0.129

Benefit-Cost Analysis

A Benefit-Cost Analysis (BCA) was completed using the OEB BCA Toolkit under the Distribution Service Test framework. The analysis incorporates avoided repair and replacement costs, avoided outage frequency impacts, and avoided criticality impacts based on Value of Lost Load (VOLL), details show in Tables J-2 to J-5.

Table J-2: VASH Table 5, Tab 6 of OEB Toolkit

Table 5: Asset Repair and Replace Costs

Asset Class	Asset Sub-Class	Unit Basis	Unit	Cost Data Year	Repair Cost	Replace Cost	Replace %
Pole	Class 6	pole	$/unit	2025	$500.00	$4,000.00	75.00%
Pole	Class 5	pole	$/unit	2025	$500.00	$4,400.00	75.00%
Pole	Class 4	pole	$/unit	2025	$500.00	$4,840.00	75.00%
Pole	Class 3	pole	$/unit	2025	$500.00	$5,324.00	75.00%
Pole	Class 2	pole	$/unit	2025	$500.00	$5,772.00	75.00%
Pole	Class 1	pole	$/unit	2025	$500.00	$6,324.00	75.00%

Table J-3: VASH Tables 6, 7 and 8, Tab 7 of OEB Toolkit

Table 6: Project Characteristics		
Project Type Inputs		
Location		Cobourg
Project Type		Early Retirement
Impact Type		Both

Table 7: Project Economic Variables		
Variable	**Unit**	**Value**
Inflation	%	2.00%
Nominal Utility Discount Rate (WACC)	%	7.00%
Social Discount Rate	%	4.00%
Baseline OM&A Cost (% of Total Costs)	%	1.50%
Scenario OM&A Cost (% of Total Costs)	%	1.50%
Tax Rate	%	26.50%
Incremental Project Non-Asset Costs	$	$0.00

Table 8: Project Lifetime Variables		
Variable	**Unit**	**Value**
Project Start Year	year	2027
Project Expected Lifetime[1]	years	45
Starting Asset's Remaining Useful Lifetime[2]	years	16
1EUL should not exceed 74		
[2]RUL only required for the early retirement program type.		

Table J-4: VASH Table 9, Tab 7 of OEB Toolkit

Table 9: Criticality Variables			
Variable	**Unit**	**Baseline Value**	**Project Value**
Average Outage Duration	minutes	140	45
Estimated Customers Interrupted (Res)	count	6	6
Estimated Customers Interrupted (Small C&I)	count	13	0
Estimated Customers Interrupted (Med/Large	count	55	0
Value of Lost Load (VOLL)	$/Outage Event	$21,501.92	$237.48
Calibration Year	year	2026	N/A
Historic Annual Outage Events[2]	Count	1.4	N/A

[2]These outages should reflect those caused by the climate perils addressed in this risk analysis. Inclusion of historic outages from other causes will inflate results.

Table J-5: VASH Table 10, Tab 7 of OEB Toolkit

Table 10: Applicable Assets											
Existing Assets			Standard Assets			Replacement Assets				Project Budget	Cost for BCA
Asset Class	Asset Sub-Class	Unit Basis	Code Asset Class	Code Asset Sub-Class	Baseline Count	Replacement Asset Class	Replacement Asset Sub-Class	Project Count	Unit Basis	Budget ($)	BCA Cost ($)
Pole	Class 6	pole	Pole	Class 6	0	Pole	Class 6	0	pole	$0.00	$0.00
Pole	Class 5	pole	Pole	Class 5	0	Pole	Class 5	0	pole	$0.00	$0.00
Pole	Class 4	pole	Pole	Class 4	0	Pole	Class 4	0	pole	$0.00	$0.00
Pole	Class 3	pole	Pole	Class 2	35	Pole	Class 2	35	pole	$202,020.00	$185,153.31
Pole	Class 2	pole	Pole	Class 2	10	Pole	Class 2	10	pole	$57,720.00	$52,900.95
Pole	Class 1	pole	Pole	Class 1	0	Pole	Class 1	0	pole	$0.00	$0.00

Results

The project demonstrates a positive economic outcome with a BCR = 2.48 with results summarized in Table J-6.

Table J-6: VASH BCA Output, Tab 8 of OEB Toolkit

Project Summary Metrics		
Metric	**Unit**	**Expected Value**
Total PV Benefits from Avoided Repairs and Replacem	PV 2027$	$91,898
Total PV Benefits from Frequency Reductions (VOLL)	PV 2027$	$97,410
Total PV Benefits from Criticality Reductions (VOLL)	PV 2027$	$400,267
Total PV Costs	PV 2027$	$238,054
BCR	ratio	2.48
Expected Annual Average CMI Reduction[1]	CMI	11,723
Expected Lifetime CMI Reduction	CMI	527,553
[1] *Simple average over project lifetime.*		

Integration into Asset Management

VASH is integrated as a planning overlay within LUI's asset management framework. Results are used in combination with ACA condition data, system reliability performance, and customer criticality to prioritize capital investments. VASH does not independently trigger asset replacement but enhances decision-making by incorporating climate-related risk and resilience considerations into existing asset renewal programs.

Conclusion

The application of the OEB VASH methodology demonstrates that targeted system hardening investments can provide cost-effective resilience benefits when aligned with asset condition and reliability drivers. LUI will continue to expand the application of VASH in future DSP cycles, including refinement of climate inputs and evaluation of additional climate perils.

Appendix K

2022 – 2026 Material Project Details

Year	Project #	Project Name
2022	EC2022-001	Elgin Street Pole-Line Rebuild - Birchwood to Chipping Park
2022	EC2021-003	Delta-Wye Meter Conversion Program
2022	EC2021-018	Victoria Street to Ontario Street
2022	EC2022-003	ROW 44/27.6 kV - Pole 73 to Burnham Street
2022	EC2022-004	Kerr Street ROW Pole Line Victoria St to Division
2022	EC2022-005	Brook Road / F5 Feeder - New 27.6 kV Feeder
2022-2023	EC2022-010	Victoria Street - Victoria Station to King Street Rebuild
2022-2026	Multiple	Customer Driven Projects
2022-2026	Multiple	New Services Connections
2022-2026	Multiple	Seal Expiry Meter Replacement
2022-2026	Multiple	Pole Replacement Program
2022-2026	Multiple	Underground Miscellaneous
2022-2026	Multiple	Overhead Miscellaneous
2023	EC2022-008	Durham St Pole line - Durham Station to King
2023	EC2022-009	King St - Pole line - Jebco
2023	EC2019-017	Outage Management System
2023-2024	EC2023-001	Victoria Substation MS28-3 - New 27.6 kV Distribution Station
2023-2026	Multiple	Fleet - Pickup Truck and Bucket Truck
2023-2024	EC2023-002	Elgin Street Pole Line Rebuild - Chipping Park to Ontario St
2024	EC2023-003	Kerr Street Rebuild - Burnham Street to Prince of Wales Drive
2024	EC2023-001B	F1/F7 Feeder Tie-Switch Installation
2024	EC2024-001	Buck / George - University to King - 28 kV Voltage Conversion
2024-2026	Multiple	Reliability Improvement Program
2024-2025	EC2023-006	Brook Rd N to Darcy (Trailsview)
2025	CE25-101	Elgin Street Pole Line Rebuild - Ontario St to William St
2025	CE-26-109	Engineering Design and Support Staff

Year	Project #	Project Name
2026	CE-26-102	Parliament Street - 25 to 89 Parliament, Colborne
2026	N/A - To be created	Covert Street - 28 kV Voltage Conversion
2026	N/A - To be created	Victoria MS28-1 Refurbishment
2026	N/A - To be created	Economic Evaluation
2026	N/A - To be created	Misc 28kV Conversions
2026	N/A - To be created	GIS Improvements
2026	N/A - To be created	Tools
2026	N/A - To be created	Software Upgrades
2026	N/A - To be created	Spring St (Furnace to Orr) 4.16 kV to 27.6 kV voltage conversion

PROJECT IDENTIFICATION	
Project ID	EC2022-001
Project Name	Elgin Street Pole Line Rebuild - Birchwood to Chipping Park
Investment Category	System Renewal
Year(s) Executed	2022
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Rebuild the Elgin Street pole line from Birchwood to Chipping Park.
Primary Driver	Asset condition - end-of-life poles on a critical distribution corridor.
COST PERFORMANCE	
Forecast Cost (DSP)	$260,000
Actual Cost	$349,023
Variance ($ / %)	2022: +$89,023 (overspend)
Variance Explanation	Delayed on the Chipping Park to Ontario segment due to Hydro One 44 kV isolation availability.
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Delayed on the Chipping Park to Ontario segment due to Hydro One 44 kV isolation availability.
Benefits Achieved	Replaces aging poles and maintains reliability on a major distribution corridor.
Notes / Supporting References	Full pole line rebuild to be completed in separate segments. Segments are tracked separately in annual budgets.

PROJECT IDENTIFICATION	
Project ID	EC2021-003
Project Name	Delta-Wye Meter Conversion
Investment Category	System Renewal
Year(s) Executed	2022
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Transformer and metering conversion work required to align customer metering with changes from the delta wye conversion program.
Primary Driver	Delta WYE conversion support.
COST PERFORMANCE	
Forecast Cost (DSP)	Not included in the Forecast
Actual Cost	2022: $63,609
Variance ($ / %)	2022: $63,609
Variance Explanation	Program is incremental to the 2017 COS and supports delta wye conversion completion.
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Planned for 2022.
Benefits Achieved	Expected to align metering with the converted distribution system.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2021-018
Project Name	Victoria Street to Ontario Street - 2021 Carry-Forward
Investment Category	System Renewal
Year(s) Executed	2022
In-Service Date / Status	Complete in 2022.
DESCRIPTION & DRIVER	
Project Description	Pole-line work from Victoria Street to Ontario Street carried forward from the 2021 capital program.
Primary Driver	Carry-forward renewal work from prior capital plan.
COST PERFORMANCE	
Forecast Cost (DSP)	Not included in the 2022 COS forecast; identified as 2021 carry-forward.
Actual Cost	2022: $405,156
Variance ($ / %)	+$405,156 versus 2022 COS forecast line item.
Variance Explanation	Timing/carry-forward variance from the 2021 capital plan rather than a new 2022 scope variance.
OUTCOMES	
Scope Delivered as Planned?	Yes - carry-forward work completed.
Schedule Performance	Completed in 2022.
Benefits Achieved	Completed prior-year renewal scope.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2022-003
Project Name	ROW 44/27.6 kV - Pole 73 to Burnham Street
Investment Category	System Renewal
Year(s) Executed	2022
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Rebuild the 44/27.6 kV right-of-way between Pole 73 and Burnham Street.
Primary Driver	Failure risks due to the assets having reached end of life and/or are in poor or very poor condition.
COST PERFORMANCE	
Forecast Cost (DSP)	2022 COS: $240,000
Actual Cost	2022: $292,540
Variance ($ / %)	2022: +$52,540
Variance Explanation	Installation of the poles in the ROW had increased complexity.
OUTCOMES	
Scope Delivered as Planned?	Completed in 2022 as planned.
Schedule Performance	The project completed in 2022, split into two segments (Pole 73–Burnham St. and Victoria Station–Division St), following the 2021 first phase.

PROJECT IDENTIFICATION	
Project ID	EC2022-004
Project Name	Kerr Street ROW Pole Line Victoria St to Division
Investment Category	System Renewal
Year(s) Executed	2022
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Pole-line rebuild on the Kerr Street right-of-way associated with enabling the future feeder.
Primary Driver	Pole-line renewal and feeder enablement.
COST PERFORMANCE	
Forecast Cost (DSP)	$195,000
Actual Cost	$209,116
Variance ($ / %)	+$14,116 (overspend)
Variance Explanation	N/A
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Completed in 2022; related feeder work continued in later years.
Benefits Achieved	Reduces safety risks and failure-related outages for the Victoria Feeder F1 (serving ~2,000 customers) while lowering future O&M costs.
Notes / Supporting References	Related multi-year feeder project is summarized under EC2022-003.

PROJECT IDENTIFICATION	
Project ID	EC2022-005
Project Name	Brook Road / F5 Feeder - New 27.6 kV Feeder
Investment Category	System Renewal / System Access
Year(s) Executed	2022
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Constructs a new 27.6 kV F5 feeder from the Brook Road substation to serve the Tribute Communities subdivision and northeast growth area. Work includes feeder construction and installation of the F5 feeder breaker.
Primary Driver	Increase capacity at Brook Station to allow for transfer of load to better support summer load demand.
COST PERFORMANCE	
Forecast Cost (DSP)	2022: $345,262
Actual Cost	2022: $347,351
Variance ($ / %)	2022: +$2,089 (overspend)
Variance Explanation	N/A
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Work was delayed by County road-widening coordination and the need to specify/order a feeder breaker after confirming the cell did not have one installed.
Benefits Achieved	Adds feeder capacity to support northeast growth and the Tribute subdivision.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2022-010
Project Name	Victoria Street - Victoria Station to King Street Rebuild
Investment Category	System Renewal
Year(s) Executed	2022-2023
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Pole-line rebuild on Victoria Street between the Victoria substation and King Street.
Primary Driver	Asset condition - end-of-life poles.
COST PERFORMANCE	
Forecast Cost (DSP)	2022 COS: $160,000.
Actual Cost	2023: $187,281
Variance ($ / %)	+$27,281(overspend)
Variance Explanation	Complexities with the pole installation along Victoria St.
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Completed in 2023.
Benefits Achieved	Renewed aging distribution infrastructure on Victoria Street.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	Multiple
Project Name	Customer Driven Projects
Investment Category	System Access
Year(s) Executed	2022-2026
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	This grouped program captures customer and developer driven projects to connect new customers, support subdivision development, complete service upgrades, accommodate new customer load, and support customer-initiated connection requirements. The work included subdivision connection work, customer service upgrades, new load connections, DER/net metering-related connection work, and associated pole line extensions required to provide access to LUI's distribution system.
Primary Driver	Customer connection requests, subdivision development activity, commercial and industrial service upgrades, customer load additions, net metering / DER connection requests, and LUI's obligation to provide customers with access to the distribution system.
COST PERFORMANCE	
Forecast Cost (DSP)	Customer-driven System Access work was included within annual System Access capital budgets and customer connection allowances. Individual customer-driven projects were not always separately forecast in the prior DSP because timing and scope depend on customer/developer readiness, permitting, and external construction schedules.
Actual Cost	2022: $152,881 2023: $500,221 2024: $2,488,412 2025: $497,397 2026: Forecast - $360,000
Variance ($ / %)	Variances are timing- and volume-driven.
Variance Explanation	Spending varied from forecast due to the timing and scope of customer-driven projects, subdivision build-out schedules, customer/developer readiness, permitting, material availability, and coordination with external parties. These projects are externally driven and are difficult to forecast with precision at the individual project level.

OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Projects were completed based on customer/developer readiness, permitting, material availability, and coordination with external parties.
Benefits Achieved	The program enabled new customer connections, supported subdivision and commercial growth, facilitated customer service upgrades, accommodated new customer load, and supported safe and reliable access to the distribution system.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2022-014/EC2023-008/EC2024-008/CE-25-106
Project Name	New Services Connections
Investment Category	System Access
Year(s) Executed	2022-2026
In-Service Date / Status	Annual recurring program.
DESCRIPTION & DRIVER	
Project Description	Customer-driven service connections, including residential service drops, panel upgrades, and small commercial connections.
Primary Driver	Customer connection requests and growth activity.
COST PERFORMANCE	
Forecast Cost (DSP)	2022-2025: $345,000 2026: $70,000
Actual Cost	2022-2025: $284,576 2026: TBD
Variance ($ / %)	2022-2025: -$60,424 (underspend) 2026: TBD
Variance Explanation	Volume-driven variance tied to connection activity.
OUTCOMES	
Scope Delivered as Planned?	Yes - volume-driven annual work.
Schedule Performance	Annual program.
Benefits Achieved	Connects new and upgraded customer services in accordance with obligations to connect.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2022-015, EC2023-009, EC2024-009, CE-25-108
Project Name	Seal Expiry Meter Replacement
Investment Category	System Access
Year(s) Executed	2022-2026
In-Service Date / Status	Recurring meter replacement program.
DESCRIPTION & DRIVER	
Project Description	Replaces meters reaching Measurement Canada seal expiry and supports smart meter renewal activity.
Primary Driver	Regulatory compliance and meter asset renewal.
COST PERFORMANCE	
Forecast Cost (DSP)	2022-2025: $90,000 2026: $70,000
Actual Cost	2022-2025: $722,399 2026: TBD
Variance ($ / %)	2022-2025: +$632,399 (overspend) 2026: TBD
Variance Explanation	overspend was due to results of the re-seal program which was higher than anticipated
OUTCOMES	
Scope Delivered as Planned?	Yes - annual replacement volume varies by seal expiry and meter program requirements.
Schedule Performance	Annual program.
Benefits Achieved	Maintains Measurement Canada compliance and supports meter modernization.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2022-013 & EC2023-007 & EC2024-007
Project Name	Pole Replacement Program
Investment Category	System Renewal (System Access in 2025 only)
Year(s) Executed	2022-2026
In-Service Date / Status	Annual recurring program.
DESCRIPTION & DRIVER	
Project Description	Condition-based and reactive pole replacements outside named corridor rebuilds.
Primary Driver	Asset condition and safety.
COST PERFORMANCE	
Forecast Cost (DSP)	2022-2025: $200,000 2026: $60,000
Actual Cost	2022-2025: $435,328 2026: TBD
Variance ($ / %)	2022-2025: +$235,328 (overspend) 2026: TBD
Variance Explanation	Pole replacements are in accordance with pole testing results. Resulting in additional actual cost for pole replacement.
OUTCOMES	
Scope Delivered as Planned?	Yes - annual scope set by inspections and field condition reports.
Schedule Performance	Annual program.
Benefits Achieved	Replaces deteriorated poles and reduces condition-related reliability/safety risk.

PROJECT IDENTIFICATION	
Project ID	EC2023-010/EC2024-010/CE-25-109
Project Name	Underground Miscellaneous
Investment Category	System Renewal
Year(s) Executed	2022-2026
In-Service Date / Status	Recurring failure-response program.
DESCRIPTION & DRIVER	
Project Description	Reactive replacement of failed underground cable, pad-mounted transformers, and underground switchgear.
Primary Driver	Asset failure response and service reliability.
COST PERFORMANCE	
Forecast Cost (DSP)	2022-2025: $163,000 2026: $55,000
Actual Cost	2022-2025: $307,018 2026: TBD
Variance ($ / %)	2022-2025: +$144,018 2026: TBD
Variance Explanation	Pad-mount transformer replacement and related underground infrastructure was replaced based on field conditions and assessments.
OUTCOMES	
Scope Delivered as Planned?	Yes - reactive scope delivered as required.
Schedule Performance	Event-driven annual program.
Benefits Achieved	Restores failed underground assets and maintain reliability.
Notes / Supporting References	N/A

PROJECT IDENTIFICATION	
Project ID	EC2022-012/EC2023-011/EC2024-011/CE-25-110
Project Name	Overhead Miscellaneous
Investment Category	System Renewal
Year(s) Executed	2022-2026
In-Service Date / Status	Recurring failure-response program.
DESCRIPTION & DRIVER	
Project Description	Reactive replacement of failed overhead components, including transformers, fuses, switches, surge arrestors and conductors outside named rebuild projects.
Primary Driver	Asset failure response and service reliability.
COST PERFORMANCE	
Forecast Cost (DSP)	2022-2025: $162,000 2026: $75,000
Actual Cost	2022-2025: $469,509 2026: TBD
Variance ($ / %)	2022-2025: $+307,509 2026: TBD
Variance Explanation	Overhead infrastructure including transformers, fuses, switches were replaced based on field conditions and assessments.
OUTCOMES	
Scope Delivered as Planned?	Yes - reactive scope delivered as required.
Schedule Performance	Event-driven annual program.
Benefits Achieved	Restores failed overhead assets and maintain reliability.
Notes / Supporting References	N/A

PROJECT IDENTIFICATION	
Project ID	EC2022-008
Project Name	Durham St Pole line - Durham Station to King
Investment Category	System Renewal
Year(s) Executed	2023
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Extension of existing 3-Ph pole line on Durham St from Durham station to King St.
Primary Driver	Upcoming Subdivision servicing
COST PERFORMANCE	
Forecast Cost (DSP)	N/A – Not included in Forecast
Actual Cost	2023: $478,410
Variance ($ / %)	N/A
Variance Explanation	Not included in the Forecast
OUTCOMES	
Scope Delivered as Planned?	Pole line upgrade complete.
Schedule Performance	Completed pole line installation as requested.
Benefits Achieved	Existing pole line upgraded from Durham St to King to Service new subdivision.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2022-009
Project Name	King St - Pole line - Jebco
Investment Category	System Renewal
Year(s) Executed	2023
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Extension of existing pole line on King St to 44kV in order to upgrade service to Jebco
Primary Driver	Service upgrade request from Jebco
COST PERFORMANCE	
Forecast Cost (DSP)	Not forecasted. Associated with customer connection
Actual Cost	2023: $239,022
Variance ($ / %)	N/A
Variance Explanation	N/A
OUTCOMES	
Scope Delivered as Planned?	Pole line extension complete.
Schedule Performance	Completed extension of existing pole line as requested.
Benefits Achieved	Pole line extension to 44 kV overhead to supply capability.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2019-017
Project Name	Outage Management System
Investment Category	System Service
Year(s) Executed	2023
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	GIS updates integrated with the Outage Management System, plus procurement and installation of ERTH SmartMap software to enhance outage visualization, GIS accuracy, and overall system reliability.
Primary Driver	Improve outage response time and data accuracy for grid reliability.
COST PERFORMANCE	
Forecast Cost (DSP)	Not forecasted
Actual Cost	2023 $509,510
Variance ($ / %)	N/A
OUTCOMES	
Scope Delivered as Planned?	Yes – GIS updates completed, ERTH SmartMap purchased and installed as specified.
Schedule Performance	Completed as planned.
Benefits Achieved	Improved outage response via ERTH SmartMap visualization and enhanced GIS accuracy and reliability.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	EC2023-001
Project Name	Victoria Substation MS28-3 - New 27.6 kV Distribution Station
Investment Category	System Access
Year(s) Executed	2023
In-Service Date / Status	Completed; energized December 2023
DESCRIPTION & DRIVER	
Project Description	Constructed a new 27.6 kV distribution station at the Victoria substation property in Cobourg. The station supplies the new F7 feeder and supports the remaining 4.16 kV to 27.6 kV conversion work.
Primary Driver	Capacity addition, voltage conversion enablement, customer growth, and reliability redundancy.
COST PERFORMANCE	
Forecast Cost (DSP)	Not included in the 2017 COS forecast.
Actual Cost	2023: $2,535,311
Variance ($ / %)	Material incremental spend versus 2017 COS; final variance requires final capitalized cost.
Variance Explanation	Need was identified after the 2017 DSP through updated system planning and Town of Cobourg growth expectations.
OUTCOMES	
Scope Delivered as Planned?	Yes - new station constructed and energized.
Schedule Performance	In service December 2023.
Benefits Achieved	Added 27.6 kV station capacity, enabled the F7 feeder, supported voltage conversion, and improved transfer capability with MS28-1.
Notes / Supporting References	F1/F7 tie-switch work is summarized separately under EC2023-001B.

PROJECT IDENTIFICATION	
Project ID	CE-25-113/EC2024-006
Project Name	Fleet - Pickup Truck and Bucket Truck
Investment Category	General Plant
Year(s) Executed	2023-2026
In-Service Date / Status	Pickup acquired in 2024; bucket truck ordered and carried forward to 2025.
DESCRIPTION & DRIVER	
Project Description	Fleet replacement for operational vehicles, including a pickup truck and bucket truck.
Primary Driver	Fleet lifecycle replacement and operational capability.
COST PERFORMANCE	
Forecast Cost (DSP)	2023-2025: $602,000 2026: $70,000
Actual Cost	2023-2025: $626,521 2026: TBD
Variance ($ / %)	2023-2025: $24,521 (Overspend) 2026: TBD
Variance Explanation	Bucket truck order was placed but delivery deferred due to manufacturer lead times.
OUTCOMES	
Scope Delivered as Planned?	Partial - pickup acquired; bucket truck delivery deferred.
Schedule Performance	Bucket truck shifted from 2024 into 2025.
Benefits Achieved	Maintains field crew mobility and aerial work capability.
Notes / Supporting References	Bucket truck carry-forward identified as job EC2024-006.

PROJECT IDENTIFICATION	
Project ID	EC2023-002
Project Name	Elgin Street Pole Line Rebuild - Chipping Park to Ontario St
Investment Category	System Renewal
Year(s) Executed	2023-2024
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Rebuild the Elgin Street pole line from Chipping Park to Ontario St.
Primary Driver	Asset condition - end-of-life poles on a critical distribution corridor.
COST PERFORMANCE	
Forecast Cost (DSP)	2023: $320,000
Actual Cost	2024: $446,477
Variance ($ / %)	2024: +$126,477 versus COS
Variance Explanation	Delayed on the Chipping Park to Ontario segment due to Hydro One 44 kV isolation availability. Material was procured in 2023 and work was completed in 2024. Larger class poles were used as well.
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Enhanced coordination with Hydro One to provide future benefits to avoid scheduling issues.
Benefits Achieved	Replaces aging poles and maintains reliability on a major distribution corridor.
Notes / Supporting References	Full pole line rebuild to be completed in separate segments. Segments are tracked separately in annual budgets.

PROJECT IDENTIFICATION	
Project ID	EC2023-003
Project Name	Kerr Street Rebuild - Burnham Street to Prince of Wales Drive
Investment Category	System Renewal
Year(s) Executed	2024
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Rebuilt the Kerr Street pole line from Burnham Street to Prince of Wales Drive, including replacement of 15 poles and installation of new 44 kV and 27.6 kV overhead conductors.
Primary Driver	Asset condition - end-of-life poles.
COST PERFORMANCE	
Forecast Cost (DSP)	Not forecasted.
Actual Cost	2024: $414,215
Variance ($ / %)	-
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	2023 work scheduled for year-end 2023 completion and completed in 2024.
Benefits Achieved	Renewed deteriorated poles and maintained 44 kV / 27.6 kV overhead supply capability.
Notes / Supporting References	-
Benefits Achieved	Reduces failure risk and outage frequency for ~2,000 customers, improves public and crew safety by eliminating non-standard 28kV-over-44kV configuration, consolidates two pole lines into one to lower future O&M costs by 60–70%, and avoids premium emergency replacement costs.
Notes / Supporting References	Related multi-year feeder project is summarized under EC2022-004

PROJECT IDENTIFICATION	
Project ID	EC2023-001B
Project Name	F1/F7 Feeder Tie-Switch Installation
Investment Category	System Access
Year(s) Executed	2024
In-Service Date / Status	Complete in 2024.
DESCRIPTION & DRIVER	
Project Description	Installed a 27.6 kV tie switch between the new F7 feeder from MS28-3 and the existing F1 feeder from MS28-1.
Primary Driver	Reliability and substation transfer capability.
COST PERFORMANCE	
Forecast Cost (DSP)	2024 budget for feeder work related to MS28-3 / F1-F7 tie-switch: $75,000.
Actual Cost	2024: $57,429.
Variance ($ / %)	-$17,571 (underspend)
Variance Explanation	Equipment used was a manual switch and installed by internal crew.
OUTCOMES	
Scope Delivered as Planned?	Yes - tie switch installed.
Schedule Performance	Completed during 2024.
Benefits Achieved	Allows LUI to offload MS28-1 onto MS28-3 if required, improving operational flexibility and reliability.
Notes / Supporting References	Companion to EC2023-001.

PROJECT IDENTIFICATION	
Project ID	EC2024-001
Project Name	Buck / George - University to King - 28 kV Voltage Conversion
Investment Category	System Renewal
Year(s) Executed	2024
In-Service Date / Status	Complete in 2024.
DESCRIPTION & DRIVER	
Project Description	Rebuilt overhead distribution on George Street from University to King and on Buck Street from George to Division to prepare the area for 27.6 kV conversion.
Primary Driver	Necessary for 4.16 kV to 27.6 kV voltage conversion in the area.
COST PERFORMANCE	
Forecast Cost (DSP)	2024: $295,000
Actual Cost	2024: $180,442
Variance ($ / %)	2024: -$114,558 (underspend)
Variance Explanation	Reduced scope due to findings from detailed design and inspection
OUTCOMES	
Scope Delivered as Planned?	Yes - project completed.
Schedule Performance	Completed during 2024.
Benefits Achieved	Prepared the Buck/George area for 27.6 kV voltage operation and addressed related overhead renewal needs.
Notes / Supporting References	N/A

PROJECT IDENTIFICATION	
Project ID	EC2024-003, EC2025-004
Project Name	Reliability Improvement Program
Investment Category	System Renewal
Year(s) Executed	2024-2026
In-Service Date / Status	2024 & 2025 scope complete; annual program continues in 2026.
DESCRIPTION & DRIVER	
Project Description	Targeted replacement of switch bracket, switch and surge arrestor assemblies on the F1 feeder and affected circuits using updated component designs.
Primary Driver	Improved reliability - elevated momentary outages on the 27.6 kV system
COST PERFORMANCE	
Forecast Cost (DSP)	2024: $100,000 2025: $50,000 2026 forecast: $50,000
Actual Cost	2024: $72,474 2025: $42,004
Variance ($ / %)	2024: -$27,526 (underspend) 2025: -$7,996 (underspend)
Variance Explanation	N/A – Completed under the budget in 2024 & 2025.
OUTCOMES	
Scope Delivered as Planned?	Yes – completed as per scope
Schedule Performance	2024 & 2025 scope completed; program continues annually.
Benefits Achieved	Reduces momentary interruption risk and targets known problem areas on the 27.6 kV system.
Notes / Supporting References	Raven Engineering relay analysis helped narrow the suspected area of component failure.

PROJECT IDENTIFICATION	
Project ID	EC2023-006
Project Name	Brook Rd N to Darcy (Trailsview)
Investment Category	System Renewal and System Service
Year(s) Executed	2024-2025
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Rebuild existing pole line from Brook Rd to Trailsview and new F5 Feeder Breaker to be installed.
Primary Driver	Asset condition - end-of-life poles on a critical distribution corridor.
COST PERFORMANCE	
Forecast Cost (DSP)	2024: $500,000
Actual Cost	2025: $708,943
Variance ($ / %)	+$208,943 (overspend)
Variance Explanation	Addition of F5 Feeder Breaker increased the actual cost.
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Delayed on the segment due to Feeder breaker addition to the scope.
Benefits Achieved	Replaces aging poles and maintains reliability on a major distribution corridor.
Notes / Supporting References	-

PROJECT IDENTIFICATION	
Project ID	CE25-101
Project Name	Elgin Street Pole Line Rebuild - Ontario St to William St
Investment Category	System Renewal
Year(s) Executed	2025
In-Service Date / Status	Completed
DESCRIPTION & DRIVER	
Project Description	Rebuild the Elgin Street pole line from Ontario St to William St.
Primary Driver	Asset condition - end-of-life poles on a critical distribution corridor.
COST PERFORMANCE	
Forecast Cost (DSP)	$460,000
Actual Cost	$504,874
Variance ($ / %)	+$44,874 versus COS
Variance Explanation	Larger class poles were used and additional coordination with Hydro One was required.
OUTCOMES	
Scope Delivered as Planned?	Completed
Schedule Performance	Enhanced coordination with Hydro One to provide future benefits to avoid scheduling issues.
Benefits Achieved	Replaces aging poles and maintains reliability on a major distribution corridor.
Notes / Supporting References	Full pole line rebuild to be completed in separate segments. Segments are tracked separately in annual budgets.

PROJECT IDENTIFICATION	
Project ID	CE-26-109
Project Name	Engineering Design and Support Staff
Investment Category	System Renewal
Year(s) Executed	Originally planned 2022; bridge-period execution planned for 2026.
In-Service Date / Status	Ongoing annual engineering support program / completed as required
DESCRIPTION & DRIVER	
Project Description	This program captures external engineering, design and technical support required to deliver LUI's capital work program and address engineering needs that arise outside of individually identified material projects. Work may include overhead and underground distribution design, drafting, field engineering, construction support, technical reviews, and limited studies required to assess emerging asset condition, safety, constructability or reliability issues.
Primary Driver	Engineering and technical support required to enable safe, compliant and timely delivery of system renewal work and to respond to emerging field conditions or technical studies as required.
COST PERFORMANCE	
Forecast Cost (DSP)	2025: $55,000 2026: $55,000
Actual Cost	2025: $89,578 2026: TBD
Variance ($ / %)	2025: 34,578 (overspend)
Variance Explanation	Spending varies year to year based on the volume and timing of LUI capital projects, field conditions encountered during design or construction, availability of internal resources, technical review requirements, and the need for external engineering support.

OUTCOMES	
Scope Delivered as Planned?	Completed as required to support delivery of LUI’s capital program and emerging engineering requirements.
Schedule Performance	Engineering support was provided based on capital project timing, field priorities, and technical review requirements.
Benefits Achieved	Supported timely delivery of safe and compliant designs, reduced project schedule risk, improved design quality and constructability, and provided technical support for reliability, safety and renewal-driven work.
Notes / Supporting References	N/A

PROJECT IDENTIFICATION	
Project ID	CE-26-102
Project Name	Parliament Street - 25 to 89 Parliament, Colborne
Investment Category	System Renewal
Year(s) Executed	Originally planned 2022; bridge-period execution planned for 2026.
In-Service Date / Status	Deferred from 2022; budgeted for completion in the bridge period.
DESCRIPTION & DRIVER	
Project Description	Rebuilds overhead distribution on Parliament Street in Colborne from south of Scott Street to the north limit of LUI service territory.
Primary Driver	Asset condition - end-of-life poles.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast = $190,000
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	planned for bridge period.
Schedule Performance	Deferred from 2022; budgeted for completion in 2026.
Benefits Achieved	Expected to renew end-of-life pole-line infrastructure in Colborne.
Notes / Supporting References	N/A

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Covert Street - 28 kV Voltage Conversion
Investment Category	System Service
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	Replacement of the existing 4.16 kV overhead distribution system with a new 27.6 kV system on ~10 poles along Covert Street from Division to George, including empty duct provision for a future Town of Cobourg parking garage.
Primary Driver	Voltage conversion, asset renewal, and Town coordination.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $295,000.
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	N/A
Benefits Achieved	Expected to complete remaining 27.6 kV conversion needs and support future Town service coordination.
Notes / Supporting References	N/A

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Victoria Station MS28-1 Refurbishment
Investment Category	System Access
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	Refurbishment and assessment work at Victoria Station MS28-1 to address deteriorated facility components, including the station roof/building envelope and related components. The work is intended to maintain the condition of the station facility, protect station equipment from further deterioration, and complete an assessment to confirm any additional refurbishment requirements.
Primary Driver	Facility condition and continued safe and reliable operation of existing station infrastructure.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $125,000
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	Planned for 2026 and to be coordinated with station access, operational requirements, and contractor availability.
Benefits Achieved	Expected benefits include maintaining the station facility in a safe and serviceable condition, reducing the risk of water ingress or further deterioration, protecting station equipment, supporting worker safety, and informing future station refurbishment requirements.

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Economic Evaluation
Investment Category	System Access
Year(s) Executed	2026
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	This program captures the utility-funded portion of customer-initiated expansion connection work that is subject to economic evaluation. The work supports distribution system extensions, service upgrades, and related infrastructure required to connect new or expanded customer load in accordance with LUI connection obligations.
Primary Driver	Customer-initiated development and load growth. obligation to provide access to the distribution system.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 bridge-year amount reflected in Appendix 2-AA: $500,000 (Gross).
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	Projects were delivered based on customer / developer readiness, permitting, municipal coordination, material availability, and construction timing.
Benefits Achieved	Enabled new and expanded customer connections, supported growth within LUI's service territory, maintained safe and reliable integration of new load, and ensured appropriate cost allocation through customer contribution mechanisms.

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Misc 28kV conversions
Investment Category	System Service
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	This program captures targeted miscellaneous 28 kV spot conversion work required to support close-out of LUI's 4.16 kV to 27.6 kV voltage conversion program. The work addresses localized residual conversion items, non-standard interfaces, and minor equipment or configuration constraints remaining after larger conversion projects are completed.
Primary Driver	Completion of the 4.16 kV to 27.6 kV conversion program and removal of residual non-standard conditions that could increase operating complexity, maintenance effort, reliability risk or safety exposure.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $100,000
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	Work is planned around outage availability, field priorities, and coordination with other conversion, renewal or operating work to minimize customer impacts.
Benefits Achieved	Supports completion of the voltage conversion program, reduces operational exceptions, improves maintainability, supports safer and more consistent operating practices, and reduces reliability risk associated with residual non-standard configurations.

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	GIS Improvements
Investment Category	System Service
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	GIS Improvements required to improve LUI's operational GIS data, network model, and migration readiness in advance of future GIS platform modernization.
Primary Driver	Operational system capability, improved outage and asset-management data quality, and preparation for reliable future integration of GIS data with LUI's operational systems.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $60,000
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	N/A
Benefits Achieved	Expected benefits include improved distribution system visibility, improved outage-management readiness, more accurate asset and connectivity data, reduced migration risk, and better operational support for engineering, operations, and field crews.

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Tools
Investment Category	General Plant
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	Replacement of tools and related equipment required to support LUI field, construction, maintenance, inspection, and operational work.
Primary Driver	Replacement and acquisition of tools required to maintain safe, reliable, and efficient field operations and support delivery of the capital and maintenance work plan.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $59,000
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	N/A
Benefits Achieved	Expected benefits include continued safe field execution, improved operational readiness, reduced reliance on aging or inadequate tools, and support for efficient completion of planned construction, maintenance, inspection, and emergency response work.

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Software Upgrades
Investment Category	General Plant
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	Purchase of office-related software and related software upgrades required to support LUI's day-to-day operations. The work includes standard productivity, collaboration, document management, reporting, and related office software tools used to support utility business processes and the delivery of the capital and operating work plan
Primary Driver	Replacement, renewal, and upgrade of office-related software required to maintain secure, reliable, and efficient business systems that support utility operations, reporting, planning, and customer service activities.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $54,563
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	N/A
Benefits Achieved	Expected benefits include continued access to reliable business software tools, improved administrative efficiency, support for accurate records and reporting, reduced risk of unsupported software.

PROJECT IDENTIFICATION	
Project ID	N/A
Project Name	Spring St from Furnace to Orr - 4.16 kV to 27.6 kV voltage conversion – Civil Portion
Investment Category	System Service
Year(s) Executed	Planned for 2026.
In-Service Date / Status	Budgeted for 2026.
DESCRIPTION & DRIVER	
Project Description	Replacement of the existing 4.16 kV overhead system with a new 27.6 kV system on ~20 poles along Spring Street (Furnace to Orr) and Orange Street, plus underground replacement south of Orange Street behind King Street West businesses.
Primary Driver	Voltage conversion, asset renewal, and improve system reliability.
COST PERFORMANCE	
Forecast Cost (DSP)	2026 forecast: $241,500
Actual Cost	TBD
Variance ($ / %)	TBD
Variance Explanation	TBD
OUTCOMES	
Scope Delivered as Planned?	Planned for 2026.
Schedule Performance	N/A
Benefits Achieved	Expected to complete remaining 27.6 kV conversion needs and support future Town service coordination.
Notes / Supporting References	N/A

APPENDIX L

2027 (TEST YEAR) MATERIAL INVESTMENTS NARRATIVES

SUMMARY

Category	Project Code	Project Name / Description	2027 Test Year Estimated Cost (Net)
System Access	SA-001	Customer Economic Evaluation Assessments	$103,000
	SA-002	New Services	$72,100
	SA-003	AMI 2.0 Program	$263,721
System Renewal	SR-001	3PH Pad Transformer Replacements	$72,100
	SR-002	Pole Replacements	$61,800
	SR-003	Underground Miscellaneous	$58,710
	SR-004	Overhead Miscellaneous	$77,250
	SR-005	Engineering Design and Support Staff	$77,250
System Service	SS-001	Spring - Furnace to Orr (4.16kV to 28 KV Conversion)	$293,550
	SS-002	Misc 28kV Conversion (Spot Replacements)	$51,500
	SS-003	Distribution System Automation	$404,678
	SS-004	Advanced Lateral Protection	$105,000
General Plant	GP-001	Facilities	$61,800
	GP-002	Software Upgrades (ERP)	$208,575
	GP-003	Software Upgrades (GIS)	$125,000

Customer Economic Evaluation Assessments – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SA-001	**2022-2026 Cost ($M):** $0.94M	**2027-2031 Cost ($M):** $0.54M
Segments: Distribution system extensions, service upgrades, and development-related connection true-ups		
Investment Category: System Access		
Trigger Driver: Customer-initiated development, load growth, and economic evaluation true-up requirements		
Outcomes: Enables customer connections; supports safe and reliable connection of new and expanded load; ensures compliance with DSC connection obligations; allocates growth-related costs between connecting customers and the general rate base; supports efficient system configuration for customer connections.		

Need for the Investment

This investment relates to customer and developer-driven connection activity, including the economic evaluation and true-up process associated with development-related system expansions. LUI is required to connect customers and expand or reinforce the distribution system where required to serve new or increased load. These investments are therefore driven by customer requests, development activity, and LUI's obligations under the DSC.

The need for this investment is not discretionary and is not driven by asset condition or routine system renewal. Rather, it reflects the capital work and associated contribution adjustments required to serve new developments and expanded customer loads while ensuring that costs are allocated appropriately between connecting customers and existing customers.

For development-related expansions, initial capital contributions are typically calculated using an economic evaluation model based on estimated expansion costs, forecast load, connection timing, and expected future distribution revenues. As projects proceed, actual construction costs, actual customer connections, timing, and realized load may differ from the assumptions used in the initial model. The economic evaluation true-up process reconciles those differences and determines whether additional customer contributions are required, whether refunds or adjustments are owing, or whether the net utility-funded portion should be reflected in rate base.

The purpose of this investment category is therefore to capture the net capital impact of development-related connection work after applying the economic evaluation and capital contribution true-up process. This ensures that growth-related costs are recovered from connecting customers where appropriate, while only the portion of the investment that provides broader system benefit is included for recovery from the general customer base.

Scope and Volume of Work

The scope includes development-related distribution system extensions, service upgrades, and associated infrastructure required to connect new customers or accommodate increased customer load. Typical work may include installation or upgrade of conductors, poles, transformers, switchgear, protection equipment, and related distribution facilities required to serve new or expanded load.

The scope also includes the financial true-up process associated with development economic evaluations. This includes comparing actual project costs, customer connection timing, forecast and actual load, and applicable revenue assumptions against the original economic evaluation used to determine customer capital contributions. The resulting true-up may affect capital contributions, refunds, or the net utility-funded amount associated with the development connection.

The annual volume of work varies based on the timing, size, location, and status of customer-initiated developments and connection requests. Because development activity can shift due to customer readiness, permitting, municipal approvals, construction timelines, and market conditions, LUI forecasts this work as an ongoing System Access program rather than as a fixed single project.

Key Timings

Development-related connection projects and related true-ups are expected to occur throughout the 2027–2031 planning period. Timing is driven by customer and developer readiness, subdivision or site plan progress, municipal and third-party coordination, permitting, construction schedules, and the timing of actual customer connections relative to the assumptions used in the economic evaluation model.

Total Capital Expenditures (Including Contributions)

Total forecast costs over the 2027–2031 period represent the expected net capital impact of development-related System Access work after considering recoveries through customer capital contributions and related economic evaluation true-ups.

The gross costs reflect the distribution infrastructure required to connect new or expanded customer load. Capital contributions and true-up adjustments reduce the amount ultimately funded by the broader customer base. No third-party contributions beyond standard customer or developer contributions are anticipated.

Economic Evaluation (DSC 3.2)

The economic evaluation process is used to assess the cost responsibility for development-related system expansions. It is not a discretionary benefit-cost analysis used to decide whether LUI should connect customers. Rather, it is a regulatory cost-allocation mechanism used to determine the capital contribution required from a connecting customer or developer and to protect existing customers from subsidizing growth-related connection costs that should be borne by the party causing the expansion.

At the initial connection stage, the economic evaluation is based on forecast assumptions, including estimated capital costs, expected customer connections, connection timing, load forecast, applicable revenue assumptions, and the expected connection horizon. As the development proceeds, those assumptions may change. The true-up process compares the original assumptions to actual project experience and determines whether the original capital contribution should be adjusted.

This approach ensures that the final cost allocation reflects actual development outcomes as closely as practical. It also ensures that LUI can meet its obligation to connect new customers while maintaining fairness between new connecting customers and existing ratepayers.

Comparative Historical Expenditures

Historical expenditures for this program reflect prior development-related connection activity and related contribution treatment. The 2022–2026 period included customer-initiated developments, service upgrades, and expansion work where capital contributions and economic evaluations were used to determine the net utility-funded amount.

Forecast spending for 2027–2031 is consistent with LUI's recent experience and reflects expected ongoing development activity, customer connection requests, and the potential for true-up adjustments as actual connection outcomes differ from initial economic evaluation assumptions.

Investment Priority

This investment is prioritized because LUI has an obligation to connect customers and to respond to customer-initiated development and load growth. Priority is determined by customer and developer timelines, connection requirements, system capacity, and the need to ensure that cost responsibility is appropriately allocated through the economic evaluation and true-up process.

Alternatives Considered

Alternatives considered include deferring connections, completing only partial system extensions, or requiring customers to rely on interim or non-standard facilities. These alternatives are not suitable where LUI has a regulatory obligation to connect customers and where permanent distribution infrastructure is required to serve new or expanded load safely and reliably.

Deferral can also create inefficient system configurations, customer service impacts, and future reinforcement costs. Proceeding with required System Access work, while applying the economic evaluation and true-up process, provides the most appropriate balance between meeting connection obligations and protecting existing customers from inappropriate growth-related costs.

Benefit-Cost Analysis (Recommended Alternative)

The recommended approach is to complete development-related System Access work as required and apply the economic evaluation and true-up process to determine the appropriate allocation of costs. The qualitative benefits include compliance with connection obligations, timely customer connections, transparent cost allocation, efficient system configuration, and avoidance of future reinforcement costs from uncoordinated development.

A separate quantitative benefit-cost analysis is not the primary decision-making tool for this program because the work is driven by customer connection obligations. The economic evaluation model serves as the appropriate mechanism for determining customer capital contributions and the net utility-funded portion of the investment.

Innovative Nature (If Applicable)

Not applicable. The work uses standard distribution planning, design, construction, and economic evaluation practices.

Leave-to-Construct Requirements (If Applicable)

Not applicable. Individual projects within this program are not expected to exceed Leave-to-Construct thresholds.

B. Evaluation Criteria and Justification

Efficiency

Coordinating development-related connections with broader system planning allows LUI to design efficient permanent infrastructure, avoid piecemeal or temporary solutions, and minimize future rework. The economic evaluation true-up process further improves efficiency by aligning final cost responsibility with actual project outcomes.

Customer Value

Customers benefit from timely access to electrical service and transparent cost allocation. Existing customers benefit because growth-related costs are assessed through capital contribution mechanisms, reducing the risk that existing customers subsidize development-related system expansions that should be paid for by connecting customers or developers.

Reliability

Development-related connection work is designed to ensure that new load can be integrated without degrading service quality or reliability for existing customers. Where system extensions or upgrades are required, the work is completed to LUI's standards and coordinated with system capacity requirements.

Safety

All connection-related work is completed in accordance with applicable design, construction, and safety standards, supporting public and worker safety.

Operations & Maintenance (O&M) Impacts / Trade-offs

Development-related connection work may add new assets to the distribution system. However, no material increase in routine O&M costs is expected beyond normal system growth. The use of standard designs and coordinated planning helps limit future maintenance complexity.

Evidence-Based Justification

The investment is supported by customer connection requests, known and forecast development activity, economic evaluation models, capital contribution calculations, and LUI's regulatory obligation to connect customers.

Asset Management Linkage

This program aligns with LUI's asset management framework by ensuring that new customer-driven assets are planned, designed, constructed, and incorporated into the distribution system in a controlled and standards-based manner.

Need Beyond AM

The program supports System Access and customer connection obligations beyond basic asset renewal. The need arises from customer-initiated development and load growth rather than the condition of existing assets.

Past Costs for Similar Projects

Forecast costs reflect LUI's recent experience with development-related system extensions, service upgrades, and capital contribution treatment, adjusted for expected construction cost escalation and development timing uncertainty.

NWS Screening

Non-wires alternatives are not applicable as a substitute for this program because customer connections and development-related expansions require physical distribution infrastructure to provide service. Demand response, DERs, or other non-wires measures do not eliminate the need for a physical connection to the distribution system.

New Services – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SA-002	**2022-2026 Cost ($M):** $0.37M	**2027-2031 Cost ($M):** $0.38M
Segments: Customer Connections – Residential		
Investment Category: System Access		
Trigger Driver: Residential customer connection requests; growth in small services; obligation to connect under distributor processes		
Outcomes: Timely residential connections, Safe and reliable energization of new residential services, Consistent customer connection experience		

Need for the Investment

This program funds the utility's rate-funded (unrecovered) portion of small residential new service connections, consistent with the distributor's connection practices and the OEB framework for residential customer connections. The program ensures the utility can connect new residential customers in a timely manner while maintaining safe installation practices and avoiding adverse reliability or power quality impacts on existing customers.

Scope and Volume of Work

The scope is limited to small residential services and associated minor distribution work required to complete the connection, such as:

- overhead service drops and underground service laterals (from the distribution system to the customer demarcation point)
- meter base-related service termination hardware and service conductors (utility-owned components up to the demarcation point)
- minor secondary extensions and service-side transformer work where directly required to provide the small service
- required protection/isolating devices and minor pole/asset hardware adjustments related to the service connection
- minimal civil/restoration directly necessary to complete the service lateral where applicable

Work volumes are driven by residential service requests and building activity within the service territory.

Key Timings

The program is planned within the 2027–2031 forecast period and will be executed continuously to meet residential connection timelines and seasonal construction windows.

Total Capital Expenditures (Including Contributions)

Total capital costs for 2027–2031 are forecast at $0.38M.

Economic Evaluation (DSC 3.2)

Economic evaluation for residential small services is primarily linked to the requirement to connect customers under established connection processes, and ensuring the distribution system is planned and built to accommodate reasonable forecast load growth, while maintaining safe and reliable operation.

Comparative Historical Expenditures

Historical spending for small residential services varies with annual residential activity and service request volumes. The 2027–2031 forecast reflects updated activity assumptions, unit cost trends for materials and labor, and recent delivery experience for small residential service work.

Investment Priority

This program is prioritized because it:

- enables timely residential customer connections
- responds to residential service request activity at the individual-service level (small services)
- reduces connection delays and customer escalations
- ensures connections are completed safely and without degrading service quality for existing customers

Alternatives Considered

Alternatives considered include deferring small service connections, restricting scope to only minimal work even where it would compromise service quality, or attempting to fully recover all small-service costs directly from residential customers.

These alternatives are not appropriate where the OEB framework for residential customer connections requires distributors to define a basic connection and recover that basic connection cost through rates (i.e., not charged to the customer), while still meeting connection timelines and safe/reliable installation requirements

Benefit-Cost Analysis (Recommended Alternative)

The recommended approach is to maintain a planned program that funds the rate-recovered basic connection portion of small residential new services, enabling predictable delivery, safe installations, and consistent customer experience. This approach reduces customer disruption from delayed connections and supports integration of new residential services consistent with distributor planning obligations.

Innovative Nature (If Applicable)

Where feasible, the program applies standard service designs, construction bundling (grouping nearby small service work), and coordinated scheduling to reduce unit costs and repeat visits.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Standardized designs and coordinated scheduling reduce repeat site visits, improve crew productivity, and support cost control for high-volume small service work.

Customer Value

Supports timely energization of new residential services and consistent treatment of residential customers, including application of the residential basic connection approach recovered through rates.

Reliability

Ensures new small services are connected without creating secondary overloads, voltage issues, or avoidable service quality impacts to nearby customers, consistent with prudent distribution planning for forecast growth.

Safety

Ensures new residential service installations meet current safety and construction practices, including appropriate protection, isolation, and installation quality.

Operations & Maintenance (O&M) Impacts / Trade-offs

Small service additions marginally increase the asset base requiring inspection/maintenance over time; however, use of standardized designs and modern materials supports maintainability and reduces corrective interventions.

Evidence-Based Justification

Justified by residential service request volumes and building activity within the service territory.

Asset Management Linkage

Supports planned asset additions with standard designs and proper records, enabling lifecycle management of the expanded service asset base.

Need Beyond AM

Supports customer access to electricity service and timely residential connections by ensuring the utility can deliver small residential services efficiently and consistently.

Past Costs for Similar Projects

Unit cost assumptions are based on recent small-service delivery experience, current market pricing, and contractor/labor conditions.

NWS Screening

Non-wires alternatives are not applicable, as the program relates to customer service connections rather than deferring distribution capacity expansions through non-wires solutions.

Advanced Metering Infrastructure 2.0 (AMI 2.0) – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SA-003	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $1.90M
Segments: Metering infrastructure		
Investment Category: System Access		
Trigger Driver: Measurements Canada compliance**,** Aging smart meter fleet, Technology lifecycle		
Outcomes: Measurement Canada compliance; Two-way AMI communications; Remote connect/disconnect capability; Interval data and enhanced analytics; Voltage monitoring and power quality visibility; Outage notification (last-gasp); Improved cybersecurity and interoperability; Foundation for future DER and EV integration.		

Need for the Investment

The Advanced Metering Infrastructure 2.0 (AMI 2.0) Program involves the structured replacement of LUI's existing single-phase (Class 1) and polyphase (Class 3) smart meter population with next-generation, two-way communicating Advanced Metering Infrastructure (AMI 2.0) devices. The program addresses three overlapping and mutually reinforcing drivers:

- Measurement Canada seal-expiry compliance obligations
- Aging meter technology approaching end of its manufacturer-supported service life
- Need to modernize LUI's metering platform to support enhanced grid operations, customer services, and future energy management capabilities.

A substantial portion of LUI's existing metering population is approaching Measurement Canada certification period, creating a mandatory compliance obligation that requires meters to be recertified or replaced. Seal-expiry analysis indicates that the largest single-year replacement volume falls in 2027, with additional cohorts requiring action through 2031. The total meters expiring within the DSP period is 9844, with replacement obligations continuing into the subsequent plan period as the remaining meters age.

LUI's compliance strategy integrates two complementary programs. The Meter Seal Re-Certification Program provides a targeted bridge mechanism for cohorts that fall due for seal sampling during the AMI 2.0 rollout period but are not yet scheduled for full replacement. Under Measurement Canada requirements, a 10% statistical sample of each meter cohort must be tested at seal expiry. Where that sample is drawn, LUI's approach is to fulfil the sampling obligation by installing new AMI 2.0 meters in place of the sampled units rather than recertifying and reinstalling the existing devices.

This converts each mandatory compliance touch-point into a productive AMI 2.0 deployment event, eliminating redundant site visits and accelerating fleet modernization. Meters from cohorts not yet scheduled for AMI 2.0 replacement may be recertified to extend their compliant service life until the AMI 2.0 program reaches them. This integrated approach ensures continuous Measurement Canada compliance across the full metering population while optimizing the pace and capital cost of the AMI 2.0 transition.

Beyond compliance, the existing meter hardware and communication modules are aging, and vendor support for the current platform is declining. As the metering population ages, failure rates and communication issues are expected to increase, driving higher troubleshooting costs, increased truck rolls, billing investigation activity, and declining data quality. Continuing to operate the existing population past its service life would increase operational costs and customer service risks without delivering any improvement in metering capability.

AMI 2.0 meters provide substantially enhanced capability relative to the existing fleet. Key advancements include two-way communications, remote connect and disconnect, interval data collection, voltage monitoring and power quality measurement, tamper detection, and outage notification functionality.

These capabilities directly support LUI's operational priorities and the performance outcomes established by the OEB, including improved outage detection and response, more accurate SAIDI and SAIFI reporting, enhanced billing accuracy, and improved customer access to consumption information.

AMI 2.0 also provides the communications and data infrastructure required to support the integration of distributed energy resources (DERs), net metering, electric vehicle charging, and other load types that are expected to grow on LUI's system over the coming decade.

Scope and Volume of Work

The AMI 2.0 Program encompasses the full replacement of LUI's 11,460 single-phase residential and polyphase commercial/industrial smart meter fleet with next-generation two-way AMI devices. The program is structured as a ten-year initiative spanning the current 2027–2031 DSP period and the subsequent plan period, with the objective of completing a full fleet replacement by 2036.

Deployment is structured around two overlapping workstreams:

1) The first is the baseline AMI 2.0 replacement program, delivering a sustained annual replacement volume calibrated to fleet size, seal-expiry concentrations, and field resource capacity.

2) The second workstream leverages the Measurement Canada 10% sampling obligation where a cohort falls due for seal sampling, LUI will install new AMI 2.0 meters at the sampled locations rather than recertifying the existing units. Sampled meters replaced this way are credited toward the annual AMI 2.0 deployment

volume, reducing the incremental replacements required under the core program for that year. Meters in cohorts not yet reached by the AMI 2.0 rollout, and whose broader population remains in acceptable condition following sampling, will be recertified to maintain Measurement Canada compliance until the AMI 2.0 program reaches them.

Based on the replacement schedule, annual deployment volumes range from approximately 793 to 1,164 units per year. LUI will evaluate procurement options including participation in group-buy arrangements with peer utilities and multi-year supply agreements to manage per-unit costs and reduce customer bill impacts over the program horizon.

Key Timings

The AMI 2.0 Program is planned to commence deployment in 2027, aligned with the beginning of the forecast period and the largest single cohort of seal-expiring meters. The 2027–2031 DSP period represents the highest-intensity phase of the program, addressing the most time-critical compliance obligations and deploying the foundational AMI 2.0 communications infrastructure. Program activity is expected to continue through the subsequent DSP cycle (2032–2036) to complete full population replacement.

Key milestones within the forecast period include:

- 2026–2027: AMI 2.0 platform selection, communications infrastructure assessment, procurement, and vendor contracting
- 2027: Commencement of Class 1 single-phase meter deployment (priority cohorts addressed) as well as initial head-end server investment to support AMI 2.0 deployment
- 2028–2031: Continuation of Class 1 replacement program; Class 3 polyphase replacements addressed per seal-expiry schedule

Total Capital Expenditures (Including Contributions)

The total capital cost for the AMI 2.0 Program within the 2027–2031 DSP period is forecast at approximately $1.9 million. No capital contributions are anticipated based on current funding assumptions. The cost estimate is based on current vendor budget pricing, recent utility AMI procurement experience, and market benchmarks for next-generation smart metering systems, communications infrastructure, and associated integration work.

Costs include metering hardware, communications modules, installation labor, head-end server infrastructure, back-office system integration (Meter Data Management / CIS interface), project management, and customer communication activities. The full ten-year program cost will be updated in LUI's subsequent DSP filing to reflect program outcomes and any changes in meter technology, communications platform, or procurement arrangements.

Economic Evaluation (DSC 3.2)

The economic evaluation for the AMI 2.0 Program is based on compliance with Measurement Canada certification requirements, avoidance of increasing costs associated with aging and declining meter infrastructure, and the delivery of enhanced operational and customer-facing capabilities. The program is evaluated on the basis of lifecycle renewal, regulatory compliance, and service modernization rather than incremental load growth.

Avoided costs include:

- Increased field troubleshooting and corrective maintenance costs associated with aging meters
- Manual meter interventions, truck rolls, and site visits required to maintain or replace failed units reactively
- Billing investigation activity and customer service impacts resulting from declining meter communication reliability and data quality
- Potential compliance penalties and regulatory exposure from operating meters beyond their Measurement Canada certification periods
- Ongoing expenditure on an aging communications platform with declining vendor support

Benefits delivered by AMI 2.0 include improved outage detection and restoration times through last-gasp notification and two-way communications, reduced field dispatch for connect/disconnect activity through remote capability, improved billing accuracy and reduced billing dispute volume through interval data and enhanced meter diagnostics, voltage monitoring data supporting power quality management and capital planning, and the customer-facing capability improvements enabled by access to interval consumption data.

Comparative Historical Expenditures

Historical expenditures for a comparable smart meter replacement program are not available for direct comparison. Given the time elapsed since the deployment of the original AMI program, the significant advancements in metering technology and communications platforms, and the different program structure, historical expenditures from the original deployment are not directly comparable to the AMI 2.0 program.

The cost estimate for this program is based on current preliminary high level budget pricing, recent peer utility AMI procurement experience in Ontario, and market benchmarks for next-generation smart metering systems and associated infrastructure.

Investment Priority

The AMI 2.0 Program is a high-priority investment within LUI's 2027–2031 capital portfolio. Priority is informed by Measurement Canada compliance obligations with defined timelines, the concentration of seal-expiring meters in 2027, increasing failure and communication risk in the aging meter population, and the strategic importance of AMI 2.0 as a foundational platform for LUI's broader digital grid and customer service modernization strategy. Deferral of the program beyond the seal-expiry schedule would create regulatory compliance risk and would defer operational and customer benefits that AMI 2.0 enables.

Alternatives Considered

The following alternatives were considered prior to recommending the AMI 2.0 full fleet replacement program:

1) Continue operating existing meters beyond service life (reactive spot replacement only):

   Not Preferred. Continued operation of the aging fleet without a structured replacement program would result in increasing failure rates, growing corrective maintenance costs, declining data quality, and progressive accumulation of compliance risk as meters exceed their Measurement Canada certification periods. This approach does not address the root cause of the investment need and would result in higher long-term costs without any improvement in metering capability.

2) Seal recertification (without replacement):

   No Preferred. Recertification alone as an alternative to AMI 2.0 replacement is not preferred, as it does not address aging communication modules, evolving cybersecurity and interoperability requirements, declining vendor support, or the need to modernize LUI’s metering platform. However, targeted recertification is being deliberately adopted as a bridge mechanism for meter cohorts that fall due for Measurement Canada seal sampling ahead of their scheduled AMI 2.0 replacement. Where a 10% sample is drawn from a cohort, LUI will install AMI 2.0 meters at the sampled locations rather than recertifying them, converting the compliance event into a replacement deployment. Remaining meters in those cohorts, where the population passes sampling and remains in acceptable condition, will be recertified to extend their compliant service life until the AMI 2.0 rollout reaches them. This integrated approach avoids premature full replacement of meters not yet scheduled under AMI 2.0, while ensuring no cohort operates outside Measurement Canada compliance at any point during the transition.

3) Partial replacement (highest-urgency cohorts only, within DSP period):

   Not preferred. While partial replacement would reduce capital expenditure within the 2027–2031 period, it would not address the full meter population compliance obligation. This option would leave a significant portion of the aging fleet in service and would forgo the network-wide communications and data benefits of a complete AMI 2.0 deployment. The ten-year full replacement approach is preferred as it provides a structured, cost-effective path to full compliance and platform modernization while allowing capital expenditure to be phased across two DSP cycles.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative combines full fleet replacement with targeted recertification as a deliberate bridge mechanism. This integrated strategy optimizes lifecycle cost while maintaining continuous Measurement Canada compliance throughout the transition period. The combined program delivers superior value relative to any single-track alternative.

Recertification defers replacement expenditure for cohorts not yet at the front of the AMI 2.0 rollout queue, reducing capital concentration in any single year. Simultaneously, the strategy of using 10% sampling events as AMI 2.0 deployment opportunities eliminates redundant site visits. The program investment of approximately $1.9M over the DSP period provides a cost-effective, compliance-assured path to full AMI 2.0 fleet modernization by 2036.

Innovative Nature (If Applicable)

The program introduces next-generation smart metering technology with enhanced capabilities using proven, industry-standard solutions.

Leave-to-Construct Requirements (If Applicable)

Not applicable. Smart meter replacement does not trigger Leave-to-Construct requirements.

B. Evaluation Criteria and Justification

Efficiency

Planned, coordinated replacement allows LUI to optimize deployment logistics, procurement volumes, and field resource scheduling, reducing per-unit installation costs relative to reactive or piecemeal replacement.

Coordinated deployment avoids repeat site visits and reduces the customer communication burden associated with unplanned meter interventions. Group procurement opportunities with peer utilities may further reduce hardware costs.

Customer Value

Customers benefit directly from AMI 2.0 through improved meter reliability, more accurate billing, and enhanced access to interval consumption data that supports informed energy management. Remote connect/disconnect capability reduces wait times for service connections and disconnections. Outage notification and voltage monitoring capabilities support faster outage detection and response, reducing customer outage duration.

Reliability

Replacing aging meters maintains reliable metering and billing operations across the system and eliminates the growing risk of meter failures, communication drop-outs, and data gaps associated with an aging fleet. AMI 2.0's two-way communications and outage notification directly support LUI's Outage Management System, improving the speed and accuracy of outage detection, isolation, and restoration. This directly contributes to improvement in SAIDI and SAIFI performance metrics.

Safety

Replacement of aging metering equipment reduces safety risks associated with degraded electrical and communication components. AMI 2.0 devices meet current cybersecurity and interoperability standards, reducing exposure to vulnerabilities present in legacy hardware and communications protocols.

Operations & Maintenance (O&M) Impacts / Trade-offs

AMI 2.0 deployment is expected to reduce corrective maintenance, meter troubleshooting, and manual field intervention requirements over time. Remote diagnostics and connect/disconnect capability reduce the volume of truck rolls required for routine metering service activities. Routine O&M requirements are expected to remain stable following program completion, with lifecycle costs for the new fleet lower than the trajectory of the aging existing fleet.

Evidence-Based Justification

The program is supported by Measurement Canada seal-expiry data confirming mandatory replacement timelines, meter age and technology lifecycle analysis, vendor confirmation of declining support for the existing platform, and operational data on increasing communication and maintenance issues in the aging fleet.

Asset Management Linkage

The AMI 2.0 Program is directly aligned with LUI's asset management framework, addressing lifecycle renewal of metering assets at the point where condition, compliance risk, and technology obsolescence converge to justify replacement. The program is informed by LUI's Asset Condition Assessment process and is consistent with LUI's asset management policies for end-of-life infrastructure renewal.

Need Beyond AM

Beyond asset renewal, AMI 2.0 supports the modernization of LUI's customer-facing infrastructure and enables future operational capabilities that are not achievable with the existing meter platform. These include support for time-of-use and dynamic pricing programs, enhanced DER and net metering management, EV load monitoring, and advanced grid analytics.

Past Costs for Similar Projects

Past costs for a comparable smart meter replacement program undertaken by LUI have not been considered in developing the capital cost estimate for this investment, due to the significant number of years elapsed since the original AMI deployment and the substantially different technology, communications platform, and program structure involved. The cost estimate for the AMI 2.0 Program is based on preliminary high level vendor budget pricing, recent peer utility procurement experience, and market benchmarks.

NWS Screening

Non-wires alternatives are not applicable. The AMI 2.0 Program addresses metering infrastructure renewal and platform modernization driven by Measurement Canada compliance obligations and technology lifecycle, rather than capacity constraints or load-serving limitations. There is no non-wires alternative that addresses the mandatory metering compliance requirement or delivers equivalent AMI capabilities.

3-Phase Pad-Mounted Transformer Replacement Program – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SR-001	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $0.38M
Segments: Underground distribution asset renewal		
Investment Category: System Renewal		
Trigger Driver: End-of-life equipment, ACA recommendations		
Outcomes: Reduced failure risk, Improved reliability and safety, Lower emergency response		

Need for the Investment

The 3-PH Pad-Mounted Transformer Replacement Program focuses on the proactive replacement of three-phase pad-mounted transformers that have reached or exceeded their useful life across the Lakefront Utilities distribution system. The need for this investment is driven by asset condition, safety, and reliability considerations, as aging pad-mounted transformers present increased risk of failure, unplanned outages, and safety hazards. Targeted replacement supports the 2027–2031 capital program objective of renewing end-of-life assets using a data-driven, risk-based approach.

Scope and Volume of Work

The scope of the program includes replacement of approximately one three-phase pad-mounted transformer annually. Replacement locations will be selected based on the recommendations of the Asset Condition Assessment (ACA) Study to ensure that the highest-risk assets are addressed first. Work includes removal of existing units, installation of new transformers, and associated equipment and connection upgrades as required.

Key Timings

The Pad-Mounted Transformer Replacement Program will be executed on an ongoing basis throughout the 2027–2031 forecast period. Annual replacement volumes and scheduling will be informed by Asset Condition Assessment results and system performance priorities to ensure that the highest-risk assets are addressed each year.

Total Capital Expenditures (Including Contributions)

The total forecast capital expenditure for the 1-Phase Pad-Mounted Transformer Replacement Program over the 2027–2031 period is $0.38 million. No customer or third-party capital contributions are anticipated for this program.

Economic Evaluation (DSC 3.2)

As a system renewal initiative addressing end-of-life equipment, the economic evaluation for this program is based on risk mitigation, improved reliability, and lifecycle cost optimization rather than incremental capacity expansion.

Comparative Historical Expenditures

Historical expenditures for pad-mounted transformer replacement activities have been reviewed as part of LUI's capital planning and asset management processes. Unit cost assumptions for this program are consistent with recent experience replacing three-phase pad-mounted transformers of comparable scope and complexity and reflect current construction practices and forecast cost escalation. Detailed historical cost comparisons are addressed at the portfolio level.

Investment Priority

This program is prioritized within the 2027–2031 capital portfolio due to the safety and reliability risks associated with aging pad-mounted transformer assets. Priority is informed by Asset Condition Assessment results and the program's role in reducing failure risk, unplanned outages, and potential safety and environmental impacts.

Alternatives Considered

Alternatives considered include continued operation until failure or reactive replacement following outages. These alternatives were deemed less effective due to increased outage risk, higher corrective maintenance costs, and potential safety impacts.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is proactive, condition-based replacement of pad-mounted transformers identified through the ACA process. Benefits include reduced failure risk, improved service reliability, enhanced public safety, and lower long-term corrective maintenance costs.

Innovative Nature (If Applicable)

Not applicable. The program employs standard utility practices for pad-mounted transformer replacement.

Leave-to-Construct Requirements (If Applicable)

Not applicable. Individual transformer replacements do not meet Leave-to-Construct thresholds.

B. Evaluation Criteria and Justification

Efficiency

Planned replacement allows work to be scheduled efficiently and coordinated with other system renewal activities.

Customer Value

Customers benefit from improved reliability and reduced likelihood of transformer-related outages.

Reliability

Replacing end-of-life pad-mounted transformers reduces failure risk and improves feeder and local service reliability.

Safety

The program mitigates safety risks to the public and field staff associated with aging oil-filled electrical equipment.

Operations & Maintenance (O&M) Impacts / Trade-offs

Proactive replacement reduces emergency response, spill risk, and corrective maintenance associated with failing transformers. Routine inspection and maintenance requirements are not expected to materially increase.

Evidence-Based Justification

The program is supported by ACA results, transformer condition assessments, and operational experience.

Asset Management Linkage

This program aligns with LUI's asset management framework by applying lifecycle-based renewal to manage risk and maintain system performance.

Need Beyond AM

The program supports compliance with safety and environmental expectations in addition to asset renewal objectives.

Past Costs for Similar Projects

Past costs for similar pad-mounted transformer replacement programs undertaken by LUI have been considered in developing the capital cost estimate for this investment. The forecasted cost reflects recent experience replacing end-of-life pad-mounted transformers, adjusted for current design standards and forecast cost escalation.

NWS Screening

Non-wires alternatives are not applicable, as the program addresses physical asset condition and safety risks rather than capacity constraints.

Pole Replacement Program – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SR-002	**2022-2026 Cost ($M):** $0.48M	**2027-2031 Cost ($M):** $0.55M
Segments: Overhead distribution asset renewal		
Investment Category: System Renewal		
Trigger Driver: ACA – identified deteriorated poles		
Outcomes: Improved system safety, Reduced outage and failure risk, Proactive lifecycle management		

Need for the Investment

The Pole Replacement Program focuses on the proactive replacement of wood distribution poles that have been identified as being in poor or deteriorated condition based on the results of Lakefront Utilities' Asset Condition Assessment (ACA) study. The need for this investment is driven by safety and reliability risks associated with aging pole infrastructure, including increased likelihood of pole failures, customer outages, and public and worker safety hazards. Proactive, planned replacement supports the 2027–2031 capital program objective of targeted renewal of end-of-life assets using a risk-based approach.

Scope and Volume of Work

The scope of the program includes the planned replacement of approximately 40 wood distribution poles over the 2027–2031 budget cycle. Work includes removal and installation of poles, framing, guying, conductor and equipment transfers, and associated hardware upgrades in accordance with current LUI design and construction standards. Replacement locations will be selected based on ACA recommendations to address the highest-risk assets first.

Key Timings

The Pole Replacement Program will be executed on an ongoing basis throughout the 2027–2031 forecast period. Annual replacement volumes will be informed by Asset Condition Assessment results and balanced to support steady resource utilization and coordination with other planned capital and maintenance activities.

Total Capital Expenditures (Including Contributions)

The total capital cost for the Pole Replacement Program over the 2027–2031 planning period is forecast at approximately $0.55 million. No capital contributions are anticipated for this safety- and reliability-driven renewal program.

Economic Evaluation (DSC 3.2)

As a system renewal initiative addressing end-of-life assets, the economic evaluation for the program is based on risk mitigation, safety improvement, and lifecycle cost optimization rather than incremental capacity expansion. Benefits are realized through reduced probability of pole failures, avoidance of emergency repairs, and lower long-term corrective maintenance costs.

Comparative Historical Expenditures

Historical pole replacement expenditures have been reviewed as part of LUI's capital planning and asset management processes. Unit cost assumptions for this program are consistent with recent experience replacing wood distribution poles of comparable scope and complexity and reflect current construction practices and forecast cost escalation. Detailed historical cost comparisons are addressed at the portfolio level.

Investment Priority

The Pole Replacement Program is prioritized within the 2027–2031 capital portfolio due to the elevated safety and reliability risks associated with deteriorated pole assets. Priority is informed by Asset Condition Assessment results and the program's role in proactively mitigating failure risk, outages, and public and worker safety hazards.

Alternatives Considered

Alternatives considered include reactive replacement following failure or deferral of replacement activities. These alternatives were deemed less effective due to higher safety risk, increased outage impacts, and higher lifecycle costs compared to proactive planned replacement.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is proactive, planned replacement of poles identified through the ACA process. Benefits include improved public and worker safety, reduced outage risk, and lower long-term corrective maintenance costs. Quantitative benefit-cost analysis will be addressed at the portfolio level.

Innovative Nature (If Applicable)

Not applicable. The program employs standard utility pole replacement practices using updated design and construction standards.

Leave-to-Construct Requirements (If Applicable)

Not applicable. Individual pole replacements do not meet Leave-to-Construct thresholds.

B. Evaluation Criteria and Justification

Efficiency

Planned replacement allows work to be bundled and executed efficiently, reducing emergency response and unplanned repairs.

Customer Value

Customers benefit from improved service reliability and reduced likelihood of outages caused by pole failures.

Reliability

Replacing deteriorated poles reduces failure risk and supports stable feeder performance across the system.

Safety

The program directly mitigates safety risks to the public and field staff by addressing structurally compromised poles.

Operations & Maintenance (O&M) Impacts / Trade-offs

Proactive pole replacement is expected to reduce ongoing inspection requirements, emergency truck rolls, and corrective maintenance associated with failing poles. No material increase in routine O&M costs is expected following replacement.

Evidence-Based Justification

The program is supported by ACA results, pole inspection data, and operational experience identifying elevated risk associated with aging pole assets.

Asset Management Linkage

This program aligns with LUI's asset management framework by prioritizing lifecycle-based renewal to manage risk and maintain service reliability.

Need Beyond AM

The program supports regulatory and safety obligations, including compliance with ESA requirements and O. Reg. 22/04.

Past Costs for Similar Projects

Past costs for similar pole replacement programs undertaken by LUI have been considered in developing the capital cost estimate for this investment. The forecasted cost reflects recent experience with planned replacement of deteriorated wood poles, adjusted for current design standards and forecast cost escalation.

NWS Screening

Non-wires alternatives are not applicable, as the program addresses physical asset condition and safety risks.

Underground Miscellaneous – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SR-003	**2022-2026 Cost ($M):** $0.36M	**2027-2031 Cost ($M):** $0.31M
Segments: Underground distribution asset renewal		
Investment Category: System Renewal		
Trigger Driver: End-of-life equipment, deteriorated condition, recurring defects, ACA recommendations (where applicable		
Outcomes: Reduced failure risk, improved reliability and safety, lower emergency response and restoration costs		

Need for the Investment

The Underground Miscellaneous Replacement Program addresses the proactive replacement of underground distribution assets that have failed, are trending toward failure, or are in poor condition and pose elevated safety and reliability risks. This program is intended for capital renewal work associated with underground assets excluding single-phase and three-phase distribution transformers. Similar to other system renewal initiatives in the capital plan, the need is driven by asset condition and operational performance, recognizing that aging or deteriorated underground components increase the likelihood of unplanned outages, customer interruptions, and reactive restoration activities. The program supports a risk-based renewal approach consistent with the system renewal framing used in the distribution asset replacement narratives.

Scope and Volume of Work

The scope includes replacement of miscellaneous underground distribution assets that are end-of-life or high-risk, excluding 1-phase and 3-phase transformers. Typical work may include replacement or renewal of underground cables, terminations, joints/splices, elbows/connectors, switchgear components and associated underground apparatus, pad/pullbox hardware, ground components, and related secondary infrastructure where renewal is required to restore asset health and maintain safety and reliability. Annual volumes will be established based on condition and risk (for example, failure history, inspection/test results where available, and observed deterioration), with work packaged to efficiently address the highest-priority needs first.

Key Timings

The program will be executed on an ongoing basis throughout the 2027–2031 period. Annual planning and scheduling will be informed by asset condition priorities, observed failures, and operational risk, enabling timely replacement before failures where practicable and ensuring that emergent high-risk items can be incorporated into the renewal plan.

Total Capital Expenditures (Including Contributions)

The total forecast capital expenditure for the Underground Miscellaneous Replacement Program over 2027–2031 is approx. $310k and will be refined through annual work planning, unit cost benchmarking, and updated condition/risk information.

Customer or third-party capital contributions are not expected for the majority of this work, as the program is primarily driven by renewal of utility-owned assets; where contributions apply for discrete projects, they will be recognized on a project-specific basis. This treatment is consistent with renewal program narratives that forecast capital without expected contributions unless specifically applicable.

Economic Evaluation (DSC 3.2)

As a system renewal initiative, the economic rationale is based on risk mitigation, reliability improvement, and lifecycle cost optimization rather than incremental load growth or capacity expansion. Replacing deteriorated underground assets reduces the probability and consequence of failures, improves restoration performance, and mitigates safety and environmental exposure associated with unplanned underground events. This aligns with the evaluation approach used for end-of-life replacement programs.

Comparative Historical Expenditures

Historical expenditures related to underground corrective replacements and renewal activities have been considered as part of capital planning and asset management processes. Unit cost assumptions will reflect recent experience with comparable underground renewal scopes and complexity, current construction practices, and forecast cost escalation.

Investment Priority

This program is prioritized within the capital portfolio due to the safety and reliability risks associated with failing or near-failing underground assets and the operational impacts of unplanned underground outages. Priority will be informed by risk ranking and field evidence, including failure history, repeat trouble locations, and identified high-risk components.

Alternatives Considered

Alternatives considered include continued operation until failure and reactive replacement following outages. These options increase outage exposure, can lead to higher corrective restoration costs, and may increase safety and environmental risk depending on the asset type and failure mode. For these reasons, proactive, condition-based renewal is preferred.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is proactive, condition- and risk-based replacement of underground miscellaneous assets that are failed or trending toward failure, selected through asset management processes and field condition evidence. Benefits include reduced failure risk, improved customer reliability, enhanced safety for the public and workers, and reduced long-term corrective maintenance and emergency response.

Innovative Nature (If Applicable)

Not applicable. The program relies on standard utility renewal practices for underground distribution assets

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Planned replacement enables efficient bundling of work by geography/feeder, coordination with other renewal activities, and reduced restoration inefficiencies compared to emergency repairs.

Customer Value

Customers benefit from reduced frequency and duration of outages associated with underground equipment failures and improved overall service continuity.

Reliability

Replacing deteriorated underground components reduces failure risk and improves feeder and local-area reliability by addressing high-risk assets before they fail.

Safety

The program mitigates safety risks to the public and field staff associated with failing underground electrical infrastructure and reduces the likelihood of hazardous fault conditions during unplanned events.

Operations & Maintenance (O&M) Impacts / Trade-offs

Proactive renewal reduces emergency response, fault investigation, and corrective maintenance associated with repeated underground failures. Routine inspection requirements are not expected to materially increase. the program is expected to reduce reactive O&M burden over time.

Evidence-Based Justification

The program is supported by observed failure trends, repeat trouble locations, condition evidence from field inspections and maintenance records, and any available assessment outputs (including ACA recommendations where applicable).

Asset Management Linkage

This program aligns with the utility’s asset management framework by applying lifecycle-based renewal and risk prioritization to maintain system performance and manage safety/reliability risk across underground assets.

Need Beyond AM

In addition to asset renewal objectives, the program supports compliance with safety and operational expectations by reducing risk exposure from unplanned underground failures and improving service continuity outcomes.

Past Costs for Similar Projects

Past costs for similar underground renewal activities have been considered in developing cost assumptions, reflecting recent experience, current standards, and forecast escalation.

NWS Screening

Non-wires alternatives are not applicable, as the driver for the program is asset condition, safety risk, and failure mitigation rather than capacity constraints.

Overhead Miscellaneous – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SR-004	**2022-2026 Cost ($M):** $0.54M	**2027-2031 Cost ($M):** $0.41M
Segments: Overhead distribution asset renewal		
Investment Category: System Renewal		
Trigger Driver: End-of-life equipment, deteriorated condition, recurring defects, ACA recommendations (where applicable		
Outcomes: Reduced failure risk, improved reliability and safety, lower emergency response and restoration costs		

Need for the Investment

The Overhead Miscellaneous Replacement Program addresses the proactive replacement of overhead distribution assets that have failed, are trending toward failure, or are in poor condition and present elevated safety and reliability risk. The program is intended for capital renewal work associated with overhead assets, excluding pole replacements and 1-phase switches that are no like-for-like. Aging or deteriorated overhead components increase the likelihood of unplanned outages, public safety exposure (including contact hazards), and storm-related restoration complexity. This program supports a risk-based renewal approach focused on replacing high-risk overhead components before failure where practicable.

Scope and Volume of Work

The scope includes replacement of miscellaneous overhead distribution assets that are end-of-life or high-risk, excluding poles and 1-phase switches that are not like-for-like. Typical work may include replacement/renewal of items such as primary conductors (localized sections), splices/connectors, cutouts and fuse holders, jumpers, insulators, crossarms and hardware, pole-top apparatus, arresters, switching components (where packaged as renewal), guying/anchors (where required to restore structural integrity for electrical assets), and other overhead equipment required to restore asset health and maintain safety and reliability. Annual volumes will be set through condition and risk prioritization (e.g., observed deterioration, failure history, and repeat-trouble locations), with work packaged for efficient execution by feeder/area.

Key Timings

The program will be executed on an ongoing basis throughout the 2027–2031 period. Annual planning and scheduling will be informed by asset condition priorities, observed failures, and operational risk, enabling timely replacement before failures where practicable and ensuring that emergent high-risk items can be incorporated into the renewal plan.

Total Capital Expenditures (Including Contributions)

The total forecast capital expenditure for the Overhead Miscellaneous Replacement Program over 2027–2031 is approx. $408k and will be refined through annual work planning, unit cost benchmarking, and updated condition/risk information

Economic Evaluation (DSC 3.2)

As a system renewal initiative, the economic rationale is based on risk mitigation, reliability improvement, and lifecycle cost optimization rather than incremental load growth or capacity expansion. Replacing deteriorated overhead assets reduces the probability and consequence of failures, improves restoration performance, and mitigates safety and environmental exposure associated with unplanned overhead events.

Comparative Historical Expenditures

Historical expenditures related to overhead corrective replacements and renewal activities have been considered as part of capital planning and asset management processes. Unit cost assumptions will reflect recent experience with comparable overhead renewal scopes and complexity, current construction practices, and forecast cost escalation.

Investment Priority

This program is prioritized within the capital portfolio due to the safety and reliability risks associated with failing or near-failing overhead assets and the operational impacts of unplanned overhead outages. Priority will be informed by risk ranking and field evidence, including failure history, repeat trouble locations, and identified high-risk components.

Alternatives Considered

Alternatives considered include continued operation until failure and reactive replacement following outages. These options increase customer interruption exposure and typically result in higher restoration costs and greater safety risk due to unplanned failures, particularly during adverse weather. Proactive, condition-based renewal is preferred to reduce risk and improve delivery efficiency.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is proactive, condition- and risk-based replacement of overhead miscellaneous assets that are failed or trending toward failure, selected through asset management processes and field condition evidence. Benefits include reduced failure risk, improved customer reliability, enhanced safety for the public and workers, and reduced long-term corrective maintenance and emergency response.

Innovative Nature (If Applicable)

Not applicable. The program relies on standard utility renewal practices for overhead distribution assets

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Planned replacement enables efficient bundling of work by geography/feeder, coordination with other renewal activities, and reduced restoration inefficiencies compared to emergency repairs.

Customer Value

Customers benefit from reduced frequency and duration of outages associated with overhead equipment failures and improved overall service continuity.

Reliability

Replacing deteriorated overhead components reduces failure risk and improves feeder and local-area reliability, including reducing repeat outage locations and improving performance during storms and high-wind events.

Safety

The program mitigates safety risks to the public and workers by addressing overhead components that pose elevated risk of contact hazards, equipment drop, arcing/fault risk, and failures that can create unsafe conditions during restoration.

Operations & Maintenance (O&M) Impacts / Trade-offs

Proactive renewal reduces emergency response, patrol and troubleshooting burden, and unplanned overtime associated with overhead failures and storm-related restorations tied to degraded components.

Evidence-Based Justification

The program is supported by observed failure trends, repeat trouble locations, condition evidence from field inspections and maintenance records, and any available assessment outputs (including ACA recommendations where applicable).

Asset Management Linkage

This program aligns with the utility's asset management framework by applying lifecycle-based renewal and risk prioritization to maintain system performance and manage safety/reliability risk across overhead assets.

Need Beyond AM

In addition to asset renewal objectives, the program supports compliance with safety and operational expectations by reducing risk exposure from unplanned overhead failures and improving service continuity outcomes.

Past Costs for Similar Projects

Past costs for similar overhead renewal activities have been considered in developing cost assumptions, reflecting recent experience, current standards, and forecast escalation.

NWS Screening

Non-wires alternatives are not applicable

Engineering Studies and Support Services – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SR-005	**2022-2026 Cost ($M):** $0.22M	**2027-2031 Cost ($M):** $0.41M
Segments: Overhead and underground distribution		
Investment Category: System Renewal (enabling / program delivery)		
Trigger Driver: Need for flexible engineering capacity to address emerging work, new studies and support engineering staff as required		
Outcomes: Timely delivery of safe, compliant designs; reduced schedule risk; improved design quality and constructability; support for reliability and safety-driven work		

Need for the Investment

This program provides engineering and technical support resources (internal support and external consultants) for miscellaneous engineering-related work that arises outside of currently identified material investments and other forecast projects. The need is driven by (i) emergent field conditions discovered during construction, (ii) safety and reliability risks requiring timely engineering response, (iii) small capital scopes that are inefficient to define as standalone projects during the DSP cycle, and (iv) evolving regulatory, code, or standards requirements. Maintaining a dedicated support envelope allows LUI to respond quickly to new needs while protecting delivery of the planned 2027–2031 portfolio.

Scope and Volume of Work

The program funds engineering support activities such as distribution line design (overhead/underground), protection and control support, SCADA/telecom design inputs, construction support and field engineering, survey and drafting, permitting and third-party coordination, standards development, minor civil/structural design, and technical reviews/QA/QC. Work is prioritized based on safety exposure, customer impact, constructability needs, and alignment with approved capital envelopes. Where specialized expertise or short-term surge capacity is required, LUI will engage qualified consulting resources under established procurement and oversight processes.

Key Timings

Engineering support services will be executed on an ongoing basis throughout the 2027–2031 forecast period. Activities will be initiated as needs arise, coordinated with annual capital re-forecasting and quarterly delivery reviews, and adjusted to reflect portfolio pacing, resource availability, and in-year risk priorities.

Total Capital Expenditures (Including Contributions)

The total capital cost for Engineering Studies and Support Services is forecast at approximately $0.41 million over the 2027–2031 planning period. No direct capital contributions are anticipated, as this envelope supports engineering effort required to deliver capital work programs and address emergent engineering needs. The budget is based on historical spend as well as anticipated future spend associated with planned program.

Economic Evaluation (DSC 3.2)

The economic evaluation for this program is based on delivery enablement and risk reduction rather than incremental capacity expansion. Benefits are realized through avoided project delays, reduced rework and change orders, improved safety-by-design outcomes, improved compliance with codes and standards, and more efficient execution of field work. Where engineering support directly enables a specific capital scope, the value is reflected in the performance and risk outcomes of the underlying investments.

Comparative Historical Expenditures

Historical engineering support costs and the use of consultants have been reviewed as part of LUI's capital planning and delivery governance processes. The forecast reflects recent experience with engineering support demands, anticipated workload over the DSP period, and expected cost escalation.

Investment Priority

This program is prioritized because it enables timely execution of safety and reliability-driven work and reduces delivery risk across the broader capital portfolio. Priority is informed by safety exposure, customer impact, regulatory/compliance timing, and the need to maintain constructability and quality standards.

Alternatives Considered

Alternatives considered include relying exclusively on internal staff capacity, deferring miscellaneous engineering work until it can be bundled into future projects. These alternatives were deemed less effective due to increased schedule risk, higher probability of rework, potential non-compliance with standards, and elevated safety and reliability exposure during emergent situations.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is to maintain a modest, controlled engineering support envelope and use a mix of internal resources and qualified consultants to address emergent needs and small capital scopes efficiently. Quantitative benefit-cost analysis, where applicable, is addressed at the portfolio level. This program primarily provides delivery enablement and risk reduction benefits.

Innovative Nature (If Applicable)

The program supports efficient delivery through standardized design templates, repeatable work packages, and use of modern engineering tools to improve quality and reduce cycle times. Where appropriate, LUI will utilize on-call consulting arrangements to improve responsiveness and cost control.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Dedicated support capacity reduces cycle time for design changes, minimizes rework, and allows resources to be deployed where they deliver the highest risk reduction and delivery benefit.

Customer Value

Customers benefit through timely completion of minor works, fewer construction delays, improved outage response coordination, and better quality outcomes that reduce repeat issues.

Reliability

Engineering support helps implement reliable designs and timely corrective scopes, supports effective switching/restoration planning, and reduces repeat interruptions due to design or constructability gaps.

Safety

Engineering oversight improves safety-by-design outcomes, ensures standards compliance, and supports timely mitigation of hazards identified in the field.

Operations & Maintenance (O&M) Impacts / Trade-offs

Proactive engineering support is expected to reduce corrective maintenance and emergency response associated with design gaps or delayed fixes. No material increase in routine O&M costs is anticipated; impacts are generally neutral to favorable.

Evidence-Based Justification

The program is supported by observed variability in in-year engineering demand, construction-stage design changes, and the need to address emergent safety and reliability issues efficiently.

Asset Management Linkage

The program supports LUI’s asset management framework by enabling timely planning, design, and execution of risk-informed investments and by improving the accuracy and completeness of asset records (e.g., as-builts and data updates).

Need Beyond AM

The program also addresses evolving external drivers, including regulatory changes, updated technical standards, third-party coordination requirements, and emergent operational risks that arise during the DSP period.

Past Costs for Similar Projects

Past costs for comparable engineering support and consulting services have been considered in developing the forecast. Unit rate assumptions reflect recent experience and expected escalation; detailed comparisons are addressed at the portfolio level

NWS Screening

Non-wires alternatives are not applicable

Spring Street (Furnace to Orr) – Electrical Portion – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SS-001	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $0.29M
Segments: Voltage Conversion		
Investment Category: System Service		
Trigger Driver: Completion of voltage conversion program		
Outcomes: Finalizes 4.16 kV system retirement, Improved efficiency and reliability, System standardization		

Need for the Investment

This project represents the electrical portion of the Spring Street voltage conversion from 4.16 kV to 27.6 kV along Spring Street from Furnace Street to Orr Street. The investment is required to complete Lakefront Utilities' long-standing 4.16 kV to 27.6 kV voltage conversion program and to retire remaining legacy 4.16kV infrastructure. Completion of the electrical scope in the 2027–2031 period follows the civil works to be completed in 2026 and enables full commissioning of the converted system.

Scope and Volume of Work

The scope of work includes installation of electrical distribution components associated with conversion of approximately 25 poles along Spring Street and Orange Street to 27.6 kV operation. Work also includes replacement of select underground distribution south of Orange Street behind the businesses fronting King Street West. In addition, LUI will complete remaining spot replacements required to fully finalize the voltage conversion in this area.

Key Timings

The electrical portion of the Spring Street voltage conversion is planned for execution within the 2027–2031 forecast period, following completion of civil works in 2026.

Total Capital Expenditures (Including Contributions)

The total capital cost for the electrical portion of the Spring Street voltage conversion is forecast at approximately $0.29 million within the 2027–2031 planning period. No capital contributions are anticipated based on the scope of work.

Economic Evaluation (DSC 3.2)

As part of a system-wide voltage conversion initiative, the economic evaluation for this project is based on improved system efficiency, reduced electrical losses, and lifecycle cost savings associated with retiring 4.16 kV infrastructure. Benefits are realized through simplified system configuration and improved long-term reliability.

Comparative Historical Expenditures

Historical expenditures for similar voltage conversion electrical works have been reviewed as part of LUI's long-term capital planning processes. Unit cost assumptions for this project are consistent with recent experience completing electrical scopes associated with 4.16 kV to 27.6 kV conversions and reflect comparable scope, construction practices, and forecast cost escalation. Detailed historical cost comparisons are addressed at the portfolio level.

Investment Priority

This project is prioritized within the 2027–2031 capital program as it enables completion of LUI's long-standing voltage conversion program and retirement of remaining 4.16 kV infrastructure. Priority was informed by the need to finalize system standardization, eliminate mixed-voltage operation, and realize the full reliability and efficiency benefits of prior civil investments.

Alternatives Considered

Alternatives considered include deferral of the electrical conversion or continued operation of mixed-voltage infrastructure. These alternatives were deemed less effective due to increased maintenance complexity, higher losses, and prolonged reliance on legacy 4.16 kV assets.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is completion of the electrical conversion following the civil works. Benefits include improved voltage performance, reduced losses, simplified system configuration, and improved long-term reliability. Quantitative benefit-cost analysis will be addressed at the portfolio level.

Innovative Nature (If Applicable)

Not applicable. The project applies established voltage conversion practices.

Leave-to-Construct Requirements (If Applicable)

Not applicable. The project does not meet Leave-to-Construct thresholds.

B. Evaluation Criteria and Justification

Efficiency

Sequencing civil works in 2026 followed by electrical completion allows efficient use of resources and avoids duplication of construction activities.

Customer Value

Customers benefit from improved voltage quality, reduced outage risk, and retirement of legacy low-voltage infrastructure.

Reliability

Completion of the voltage conversion improves feeder performance and reduces failure risk associated with aging 4.16 kV assets.

Safety

Modernizing the distribution system enhances public and worker safety and reduces exposure associated with outdated infrastructure.

Operations & Maintenance (O&M) Impacts / Trade-offs

Completion of the conversion reduces long-term maintenance complexity and eliminates the need to support mixed-voltage systems. No material increase in routine O&M costs is expected following completion.

Evidence-Based Justification

The project is supported by prior DSP commitments and long-term system planning objectives to complete the voltage conversion program.

Asset Management Linkage

This project aligns with LUI's asset management framework by retiring end-of-life assets and improving lifecycle performance through planned modernization.

Need Beyond AM

The project supports broader system efficiency, sustainability, and operational consistency objectives beyond basic asset renewal.

Past Costs for Similar Projects

Past costs for similar voltage conversion projects undertaken by LUI have been considered in developing the capital cost estimate for this investment. The forecasted cost reflects recent experience completing electrical conversion work associated with retiring 4.16 kV infrastructure, adjusted for current design standards and forecast cost escalation.

NWS Screening

Non-wires alternatives are not applicable, as the project addresses system configuration and asset condition rather than capacity constraints.

Misc 28kV Conversions (Spot Replacements) – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SS-002	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $0.05M
Segments: Voltage Conversion		
Investment Category: System Service		
Trigger Driver: Completion of 4.16–27.6 kV conversion; residual locations requiring final spot remediation		
Outcomes: Safe and fully standardized 27.6 kV system, reduced operational exceptions, improved reliability and maintainability		

Need for the Investment

LUI is nearing completion of the 4.16–27.6 kV voltage conversion program. As the main conversion work concludes, a limited number of localized "spot" issues typically remain that must be addressed to fully finalize the conversion and eliminate remaining non-standard conditions. These residual locations can include legacy equipment interfaces, localized conductor/equipment limitations, protection or switching configuration inconsistencies, and other conversion-related constraints that if left unresolved create ongoing operational exceptions, higher maintenance burden, elevated fault/outage risk, and safety exposure. This program provides the capital mechanism to systematically close out the remaining conversion gaps and ensure the system operates as a complete and consistent 27.6 kV network.

Scope and Volume of Work

The program scope consists of targeted 27.6 kV miscellaneous spot replacements required to complete conversion close-out, implemented as discrete, localized work packages. Typical scope may include localized replacement of primary cable or overhead conductor sections, terminations and joints/splices, elbows/connectors, protection and switching components arrester, and associated station/line interface components where needed to remove residual conversion constraints.

Key Timings

Work will be executed as a focused close-out initiative following substantial completion of the main conversion program. Priorities will be set to resolve the highest-risk locations first, with the objective of removing remaining conversion-related exceptions over the 2027–2031 period (or sooner where practicable), including coordination with planned outages and other renewal activities to reduce customer impacts.

Total Capital Expenditures (Including Contributions)

The total capital cost is forecast at approximately $51k within the 2027–2031 planning period. No capital contributions are anticipated based on the scope of work.

Economic Evaluation (DSC 3.2)

The economic rationale is based on avoiding the cost and risk of carrying residual conversion gaps forward. Completing spot replacements reduces the probability and consequence of failures linked to remaining non-standard equipment interfaces, improves system operability (including switching flexibility), reduces ongoing maintenance and troubleshooting effort, and lowers the likelihood of prolonged outages caused by constrained or non-standard configurations. The investment also supports lifecycle optimization by enabling standard 27.6 kV equipment practices and reducing the need for custom operational workarounds.

Comparative Historical Expenditures

Historical costs from the tail-end of major conversion programs and comparable close-out scopes will inform unit cost assumptions. The forecast will be updated as actual close-out work is completed and remaining volumes are validated.

Investment Priority

This program is prioritized to complete voltage conversion and remove remaining high-risk non-standard conditions.

Alternatives Considered

Alternatives include deferring spot remediation and managing residual exceptions through operational workarounds and corrective maintenance. This will delay finalization of the full voltage conversion program.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is a targeted, risk-based close-out program of 28 kV miscellaneous spot replacements that eliminate residual conversion gaps and standardize remaining interfaces. Benefits include improved safety, improved reliability and restoration performance, reduced operational exceptions and troubleshooting time, and improved maintainability through consistent 27.6 kV standards and practices.

Innovative Nature (If Applicable)

Not applicable. The project applies established voltage conversion practices.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Planned close-out spot replacements allow work to be packaged by feeder/area, coordinated with outages, and executed more efficiently than repeated operational workarounds or reactive restoration.

Customer Value

Customers benefit from improved service continuity, reduced likelihood of prolonged outages associated with constrained switching/restoration, and completion of system standardization that supports consistent performance.

Reliability

Eliminating residual conversion constraints reduces failure risk and improves switching flexibility and restoration capability on the 27.6 kV system.

Safety

Removing non-standard or legacy conversion interfaces reduces safety exposure for workers and the public, including reducing the likelihood of fault conditions tied to incompatible or degraded interfaces.

Operations & Maintenance (O&M) Impacts / Trade-offs

The program reduces ongoing O&M burden associated with maintaining mixed or exception configurations, including troubleshooting, specialized parts/knowledge, and additional switching/restoration complexity.

Evidence-Based Justification

The project is supported by prior DSP commitments and long-term system planning objectives to complete the voltage conversion program.

Asset Management Linkage

This project aligns with LUI's asset management framework by retiring end-of-life assets and improving lifecycle performance through planned modernization.

Need Beyond AM

The project supports broader system efficiency, sustainability, and operational consistency objectives beyond basic asset renewal.

Past Costs for Similar Projects

Past costs for similar voltage conversion projects undertaken by LUI have been considered in developing the capital cost estimate for this investment. The forecasted cost reflects recent experience completing electrical conversion work associated with retiring 4.16 kV infrastructure, adjusted for current design standards and forecast cost escalation.

NWS Screening

Non-wires alternatives are not applicable, as the project addresses system configuration and asset condition rather than capacity constraints.

System Automation Program – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SS-003	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $1.28M
Segments: Overhead distribution, protection and control infrastructure		
Investment Category: System Service		
Trigger Driver: Reliability improvement, Restoration time reduction, Operational resilience		
Outcomes: Reduced customer minutes of interruption, Faster fault isolation and service restoration, Improved operational flexibility and visibility, Foundational enablement of advanced feeder automation		

Need for the Investment

Lakefront Utilities Inc. proposes targeted distribution system automation investments to improve feeder reliability and reduce outage duration across its 27.6 kV and 44 kV distribution systems. These investments address the operational limitations of manual switching and field-based restoration practices, which extend restoration time during permanent and transient feeder events, particularly those driven by vegetation contact and weather-related disturbances.

Automation-enabled switching reduces restoration time, limits the number of customers affected by sustained outages, and improves the utility's ability to respond efficiently during both planned and unplanned system events. This program is consistent with LUI's Distribution Automation Strategy, which describes automation as coordinated use of switching devices, sensing, communications, and provide alarms/status back to operators.

Scope and Volume of Work

The program consists of implementing a practical first phase of feeder automation on selected 27.6 kV and 44 kV feeders by installing approximately 15 automated switching devices over 2027–2031. The device mix includes three-phase automated loadbreak switches installed at strategic feeder sectionalizing and tie locations, and three-phase automated reclosers where fault interruption capability and enhanced protection functionality are required.

The selected deployment approach aligns with the Strategy's "basic approach" to divide each feeder into two sections using a mid-feeder switching device and a normally open tie to an alternate feeder. This requires about 1.5 switching points per feeder and can reduce the number of customers affected by a permanent outage by roughly 50% as an initial phase of distribution automation.

The program also includes SCADA-related upgrades required to support automation at scale. Final device placement and sequencing will be confirmed through detailed engineering and implementation planning, including feeder section definition (customers/load balance), tie location selection, critical load considerations, communications readiness, protection settings, and commissioning requirements

Key Timings

Deployment will occur progressively throughout the 2027–2031 forecast period and will be coordinated with feeder renewal work, planned outages, and broader system configuration initiatives to optimize construction efficiency and minimize customer impact.

Total Capital Expenditures (Including Contributions)

The total gross capital cost for the program over 2027–2031 is $1.89 million, representing automated switching devices and supporting installation costs. The program is expected to receive $0.606 million in external funding through the Smart Renewables and Electrification Pathway (SREP), resulting in a net capital requirement of $1.28 million over the planning period.

These amounts reflect the unit costs and quantities shown in LUI's Distribution Automation capital breakdown and the approved scope of approximately 15 automated switching installations.

Economic Evaluation (DSC 3.2)

The economic evaluation is based on reduced outage duration through faster fault isolation and restoration, improved operational efficiency and reduced manual switching requirements, and enhanced situational awareness during outage response. Benefits are realized through faster fault isolation, reduced customer minutes of interruption, and improved situational awareness for system operators.

The Strategy further supports the rationale that sectionalizing and tie automation reduces the number of customers impacted by permanent outages in the initial phase.

Comparative Historical Expenditures

Historical expenditures for automation and SCADA-related investments have been reviewed as part of LUI's capital planning and reliability improvement processes. Unit cost assumptions are consistent with recent experience of neighboring utilities deploying automation devices and associated SCADA integration, reflect comparable scope and technology, and include forecast cost escalation.

Investment Priority

The program is prioritized within the 2027–2031 capital portfolio due to its ability to deliver measurable reliability improvements across multiple feeders, its alignment with LUI's automation strategy, and its role in supporting efficient system operations during outage conditions

Alternatives Considered

Alternatives considered include continued reliance on manual switching and reactive restoration practices, or limiting investment to conventional device replacement without SCADA-integrated automation functionality. These alternatives are less effective due to longer outage durations, increased operational burden, and reduced situational awareness during system events.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is a phased implementation consistent with the Strategy's initial "basic approach" (approximately 1.5 switching points per feeder) using a practical mix of automated loadbreak switches and reclosers at selected sectionalizing and tie points. This approach balances capital efficiency with meaningful reliability improvement by focusing investments where outage mitigation potential is highest and by enabling faster fault isolation and restoration.

Innovative Nature (If Applicable)

The program implements proven distribution automation practices by coordinating intelligent field devices, communications, and SCADA decision support to enable automated or semi-automated switching actions, improve outage response, and enhance operational visibility using established industry technologies.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Remote operation and automation reduce the need for manual switching and field dispatch, improving operational efficiency during both normal and outage conditions.

Customer Value

Customers benefit from reduced outage duration, faster restoration, and improved service reliability as feeder sections can be isolated and restored more quickly, reducing the number of customers affected by sustained interruptions during feeder events.

Reliability

Automated fault interruption and sectionalizing improve feeder performance by narrowing the faulted area and enabling restoration to non-faulted sections through switching and tie capabilities. The use of reclosers and switches also supports improved protection coordination and operational flexibility across normal and alternate configurations.

Safety

Automation reduces the need for field crews to perform manual switching under hazardous conditions, improving worker and public safety during restoration activities.

Operations & Maintenance (O&M) Impacts / Trade-offs

Automated devices require periodic inspection and maintenance, as well as communications and firmware management. Overall O&M impacts are expected to be neutral to favorable, as reduced emergency response, fewer manual switching operations, and improved outage coordination are expected to offset incremental maintenance requirements.

Evidence-Based Justification

The program is supported by LUI's Distribution Automation Strategy and industry-standard deployment approaches that emphasize the enabling building blocks for automation and a practical first phase based on feeder sectionalizing and tie points to reduce outage impact.

Asset Management Linkage

The program supports asset management and system planning objectives by improving controllability, protection coordination, and operational performance of the distribution system. These automation investments enhance LUI's ability to manage system risk proactively and support long-term reliability and resilience objectives beyond traditional asset renewal.

Need Beyond AM

Beyond asset renewal, the program supports resiliency, severe weather response, and modernization objectives through improved restoration capability and operational decision support.

Past Costs for Similar Projects

Past costs for similar automation and switching projects undertaken by neighboring utilities have been considered in developing the capital cost estimate. The forecast reflects recent experience with automated switching device deployment and supporting infrastructure, adjusted for current design standards and forecast cost escalation.

NWS Screening

Non-wires alternatives are not applicable, as the program addresses reliability and operational performance rather than deferral of capacity investments.

Advanced Lateral Protection – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: SS-004	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $0.1M
Segments: Overhead distribution, lateral protection infrastructure		
Investment Category: System Service		
Trigger Driver: Reliability improvement, Restoration time reduction, Operational resilience		
Outcomes: Reduced sustained interruptions on lateral circuits; Improved fault isolation on laterals; Reduced customer minutes of interruption; Improved feeder reliability performance at targeted locations		

Need for the Investment

Lakefront Utilities Inc. proposes targeted advanced lateral protection investments to improve reliability at selected locations on its overhead distribution system where existing lateral protection is inadequate. These investments address locations that are more susceptible to sustained customer interruptions due to limited lateral fault-clearing capability and where reliability performance indicates a need for focused protection upgrades.

Advanced lateral protection devices allow temporary faults to clear without unnecessarily causing sustained outages, while still isolating permanent faults where required. This improves service continuity for customers served from the affected laterals and supports more efficient outage response and restoration.

Scope and Volume of Work

The program consists of installing advanced lateral protection devices at approximately 15 locations in 2027. The installations are intended to strengthen lateral protection on selected portions of the overhead distribution system where existing protection is not considered adequate based on system configuration and observed reliability performance.

Location prioritization will be based primarily on two factors: (1) locations that currently lack adequate lateral protection, and (2) reliability statistics indicating higher outage frequency, longer outage duration, or recurring interruption performance concerns.

Key Timings

Deployment is planned for 2027. The program will be implemented as a targeted reliability initiative within Year 1 of the forecast period, with site selection, engineering review, procurement, and field installation coordinated to optimize construction efficiency and outage planning.

Total Capital Expenditures (Including Contributions)

The total gross capital cost for the program over 2027–2031 is $0.105 million, with expenditures forecast in 2027. No capital contributions are assumed. This amount reflects the estimated supply and installation cost for approximately 15 locations, including associated engineering and implementation activities.

These amounts reflect the limited, targeted scope of the proposed advanced lateral protection program and the prioritization of installations at locations with identified lateral protection gaps and reliability needs.

Economic Evaluation (DSC 3.2)

The economic evaluation is based on reliability improvement through reduced sustained interruptions, improved lateral fault isolation, and lower restoration burden at targeted locations. Benefits are expected to be realized through improved interruption performance on laterals that currently lack adequate protection and through prioritization of installations at locations with less favorable reliability statistics.

This targeted approach is intended to direct limited capital funding to the portions of the system where outage mitigation value is expected to be greatest.

Comparative Historical Expenditures

Historical expenditures for comparable lateral protection upgrade programs are limited as this is a new program. Cost assumptions are based on current budgetary estimates for targeted lateral protection installations and reflect the relatively narrow scope of the proposed 2027 program.

Investment Priority

The program is prioritized within the 2027 capital portfolio due to its ability to address identified gaps in lateral protection and deliver focused reliability improvement at selected locations with demonstrated interruption performance concerns. Given the modest capital requirement, the program represents a practical and targeted reliability investment.

Alternatives Considered

Alternatives considered include continued reliance on existing lateral protection arrangements and reactive response to recurring interruption issues. This alternative is less effective because it does not proactively address locations with known protection limitations or reliability concerns.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is targeted installation of advanced lateral protection devices at approximately 15 priority locations in 2027. This approach balances limited capital cost with measurable reliability benefit by focusing on locations that lack adequate lateral protection and exhibit weaker reliability performance. The targeted nature of the program allows LUI to improve protection performance and reduce sustained customer interruptions without undertaking a broader and more capital-intensive automation program.

Innovative Nature (If Applicable)

The program applies proven lateral protection technology in a targeted manner to improve reliability performance on selected overhead distribution circuits.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

The targeted nature of the program improves capital efficiency by directing investment only to those locations where lateral protection is currently inadequate and where reliability improvement potential is highest.

Customer Value

Customers benefit from improved service continuity and reduced sustained interruptions at the selected locations. By improving fault-clearing performance on laterals, the program is expected to reduce the number and duration of interruptions experienced by affected customers.

Reliability

Installations improve lateral protection performance by reducing the likelihood that temporary faults result in sustained outages and by isolating permanent lateral faults more effectively. Prioritizing locations using reliability statistics supports a data-driven reliability improvement approach.

Safety

Improved protection performance supports safer system operation by reducing prolonged fault exposure and supporting more controlled isolation of faulted lateral sections.

Operations & Maintenance (O&M) Impacts / Trade-offs

Advanced lateral protection devices may introduce modest inspection, coordination, and maintenance requirements; however, overall O&M impacts are expected to be neutral to favorable due to reduced outage response burden and fewer sustained interruption events at targeted locations.

Evidence-Based Justification

The program is supported by system review identifying locations with inadequate lateral protection and by reliability statistics that indicate where focused protection upgrades are most justified.

Asset Management Linkage

The program supports asset management and system planning objectives by addressing operational performance gaps on the overhead distribution system and improving protection effectiveness at selected lateral locations.

Need Beyond AM

Beyond traditional asset renewal, the program supports reliability improvement and operational resilience by strengthening lateral protection performance at targeted locations with demonstrated need.

Past Costs for Similar Projects

Past costs for similar targeted lateral protection upgrades have informed the budget estimate at a high level, with the forecast reflecting the intended scale of approximately 15 installations in 2027.

NWS Screening

Non-wires alternatives are not applicable, as the program addresses protection and reliability performance rather than deferral of capacity-related investments.

Facilities – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: GP-001	**2022-2026 Cost ($M):** $0.04M	**2027-2031 Cost ($M):** $0.1M
Segments: Facilities and Buildings		
Investment Category: General Plant		
Trigger Driver: Building condition, lifecycle renewal, code/safety compliance, operational requirements, workforce health and safety		
Outcomes: Safe and functional workplaces, reduced unplanned facility failures, improved productivity and readiness, improved working conditions in fleet garage		

Need for the Investment

Facilities and buildings are critical to enabling safe, reliable utility operations, including dispatch, line and cable operations, fleet maintenance, warehousing, emergency response, and administrative support. As facilities age, building components and systems (envelope, HVAC, electrical, plumbing, fire/life safety, and structural elements) deteriorate and can lead to safety risks, service disruptions, higher reactive repair costs, and reduced operational effectiveness. This program provides ongoing capital investment to address typical upgrades and renewal needs across LUI's facilities portfolio on a planned, condition-based basis, minimizing unplanned failures and ensuring facilities remain fit-for-purpose.

A specific near-term priority within this program is improving thermal performance and working conditions in the fleet garage where crews and staff perform daily work.

Scope and Volume of Work

The program includes capital renewal and upgrades for facilities and buildings required to maintain safe and functional operations. Typical scope may include roof replacements and repairs, building envelope and weatherproofing, doors and bay systems, flooring and structural repairs, HVAC renewal and controls upgrades, lighting and electrical distribution upgrades within facilities, plumbing replacements, fire and life safety system upgrades, security/access control systems, and building automation and energy-efficiency improvements where justified.

For the fleet garage, scope includes installation of insulation (walls/roof/ceiling as applicable), air sealing, and related envelope upgrades needed to achieve improved indoor conditions. Where required, supporting upgrades may include ventilation adjustments, heating system tuning or replacement, and moisture management measures to maintain a safe and durable building environment.

Work will be prioritized annually based on condition assessments, failure history, inspection findings, operational risk, code compliance needs, and impacts on frontline operations. Annual volumes will be developed through an annual facilities capital plan that bundles work by site and coordinates construction windows to minimize disruption.

Key Timings

The program is ongoing throughout the 2027–2031 period. Work will be sequenced to address high-risk or high-impact facility components first, with coordination around operational constraints (e.g., maintaining garage availability, emergency response readiness, and business continuity). The fleet garage insulation improvements will be scheduled to minimize impacts to fleet and crew operations, with execution timed to maximize benefit prior to peak seasonal temperature exposure where practicable.

Total Capital Expenditures (Including Contributions)

The total capital cost for the Facilities Program is forecast at approximately $106k over the 2027–2031 planning period. No capital contributions are anticipated.

Economic Evaluation (DSC 3.2)

The economic rationale is based on lifecycle renewal, risk mitigation, and avoiding higher corrective repair costs and operational disruption. Planned renewal extends the useful life of facilities, reduces emergency repairs, supports efficient delivery of field operations, and reduces safety exposure. For the fleet garage insulation, benefits include improved working conditions, reduced temperature-related productivity loss, and potential reduction in heating energy use (where applicable), supporting both operational efficiency and workforce health and safety outcomes.

Comparative Historical Expenditures

Historical facilities renewal and upgrade spending informs unit cost assumptions and expected renewal volumes. Forecasts will be updated as condition assessments and project scoping refine the work plan across sites.

Investment Priority

Facilities renewal is prioritized based on safety and compliance risk, likelihood and consequence of failure, criticality of the facility to operations, and the impact of facility deficiencies on frontline work and emergency response readiness. The fleet garage insulation component is prioritized due to direct impact on crew working conditions and operational readiness.

Alternatives Considered

Alternatives include continued operation with reactive maintenance and deferring upgrades until failures occur. This approach increases the risk of unplanned downtime, can raise costs due to emergency repairs and accelerated deterioration, and may create ongoing health and safety and compliance risks. For the fleet garage, deferral would prolong suboptimal working conditions and can negatively affect productivity and staff well-being. Planned, condition-based renewal and targeted upgrades are preferred.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is a planned, condition-based Facilities and Buildings Renewal Program combined with targeted improvements to address high-impact deficiencies, including insulation upgrades to the fleet garage. Benefits include safer and more reliable facilities, reduced unplanned failures and reactive costs, improved operational effectiveness, and improved working conditions for crews and staff.

Innovative Nature (If Applicable)

Not applicable.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Planned renewal allows bundling of work by site and system, reduces emergency callouts, and improves scheduling efficiency while minimizing operational disruption.

Customer Value

Reliable facilities support reliable field operations and emergency response, indirectly supporting customer service continuity and restoration performance.

Reliability

Maintaining critical operational facilities reduces the risk of disruptions to fleet readiness, dispatch, warehousing, and field response capabilities.

Safety

The program reduces safety risks related to deteriorated building systems and improves workplace conditions. Fleet garage insulation specifically improves thermal comfort and reduces exposure to extreme temperatures for crews.

Operations & Maintenance (O&M) Impacts / Trade-offs

Planned capital renewal reduces reactive O&M and extends asset life. Insulation upgrades may reduce heating demand and reduce wear on heating equipment over time.

Evidence-Based Justification

Justification will be supported by facility condition assessments, inspection findings, failure history, health and safety observations, and operational feedback from site users.

Asset Management Linkage

The program aligns with lifecycle management of non-electrical infrastructure needed to deliver utility operations, ensuring facilities remain fit-for-purpose and appropriately maintained.

Need Beyond AM

In addition to lifecycle renewal, the program supports workforce readiness, business continuity, and health and safety objectives, particularly in operational facilities such as garages.

Past Costs for Similar Projects

Costs will reflect recent experience with similar facility renewals and upgrades, adjusted for site-specific conditions and escalation.

NWS Screening

Non-wires alternatives are not applicable

Software Upgrades (ERP) – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: GP-002	**2022-2026 Cost ($M):** $0.05M	**2027-2031 Cost ($M):** $0.26M
Segments: Information systems		
Investment Category: General Plant		
Trigger Driver: Aging platforms, Cybersecurity and operational risk		
Outcomes: Improved efficiency and data integrity, Productivity gains		

Need for the Investment

The Software Upgrades Program supports continuous improvement of Lakefront Utilities' Enterprise Resource Planning (ERP) system. The need for this investment is driven by system aging, evolving regulatory and operational requirements, and the need to maintain secure, reliable, and efficient business operations.

Scope and Volume of Work

The scope of work includes multi-year upgrades or replacement of ERP platform, encompassing software configuration, data migration, system integration, testing, training, and change management activities. Final scope and sequencing will be confirmed through detailed project planning and procurement.

Key Timings

This program will be executed over multiple years within the 2027–2031 forecast period due to implementation complexity and the need for phased rollout, risk mitigation, and organizational change management. Sequencing and timing will be finalized through detailed project planning and procurement.

Total Capital Expenditures (Including Contributions)

The total capital cost for the Software Upgrades Program is forecast at approximately $0.26 million over the 2027–2031 planning period, reflecting licensing and implementation costs. No capital contributions are anticipated based on current funding assumptions.

Economic Evaluation (DSC 3.2)

The economic evaluation for the program is based on improved operational efficiency, system reliability, regulatory compliance, and reduced manual effort rather than incremental capacity expansion. Benefits accrue through streamlined workflows, reduced system maintenance risk, and improved customer service outcomes rather than incremental load growth.

Comparative Historical Expenditures

Historical expenditures for ERP and other enterprise software upgrades have been reviewed as part of LUI's capital planning and asset management processes. Cost assumptions for this program are consistent with recent experience implementing major business system upgrades of comparable scope and complexity and reflect current vendor pricing and forecast cost escalation. Detailed historical cost comparisons are addressed at the portfolio level.

Investment Priority

This program is prioritized within the 2027–2031 capital portfolio to ensure continuity of core business systems, manage operational and cybersecurity risk, and support efficient service delivery. Priority is informed by system age, vendor support considerations, and the importance of ERP platform to regulatory compliance and productivity.

Alternatives Considered

Alternatives considered include deferring system upgrade or implementing limited patches to existing platform. These alternatives were deemed less effective due to increasing vendor support risk, growing technical debt, and heightened cybersecurity exposure.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is a phased upgrade of the ERP platform. The total capital investment of $0.26M over 2027–2031 is expected to generate benefits that outweigh the cost of the program from the following factors:

1. **Labor Efficiency Gains:** ERP modernization is estimated to reduce manual data entry, reconciliation, and reporting effort across Finance, HR, and Operations functions.

2. **Avoided IT Support and Maintenance Costs:** The current legacy ERP environment requires ongoing vendor workarounds, custom patches, and elevated IT support to maintain stability.

3. **Cybersecurity Risk Reduction:** Operating on an aging, partially unsupported ERP platform creates material cybersecurity exposure.

4. **Regulatory and Audit Compliance:** Modernized ERP systems support automated audit trails, improved data lineage, and structured reporting outputs. Also, Reduced manual effort in regulatory filings and improved data quality are estimated to save significant time across regulatory, finance, and compliance functions.

5. **Improved data integrity**: This supports more informed capital and operational planning, enhanced business continuity by eliminating dependence on end-of-life or minimally supported software, improved employee experience through reduced

manual workarounds and modernized user interfaces, and a strengthened foundation for future digital initiatives including advanced analytics and integration with operational technology systems.

Innovative Nature (If Applicable)

The program incorporates modern enterprise software platform

Leave-to-Construct Requirements (If Applicable)

Not applicable. Software upgrades do not trigger Leave-to-Construct requirements.

B. Evaluation Criteria and Justification

Efficiency

Modernized systems reduce manual processing, duplication of effort, and reliance on workarounds associated with legacy platforms.

Customer Value

Customers benefit indirectly through improved billing accuracy, service responsiveness, and system reliability.

Reliability

Upgraded ERP platform improves system stability, data integrity, and business continuity.

Safety

The program supports cybersecurity and data protection, reducing risk associated with system vulnerabilities.

Operations & Maintenance (O&M) Impacts / Trade-offs

Following implementation, the program is expected to reduce ongoing IT support effort associated with legacy systems and improve system reliability. O&M costs are expected to stabilize following the transition period, with no material long-term increase anticipated.

Evidence-Based Justification

The program is supported by system lifecycle considerations, vendor roadmaps, and operational experience with existing platforms.

Asset Management Linkage

A modernized ERP platform supports asset management by improving data integrity, lifecycle tracking, and reporting capability, enabling more informed planning and investment decisions.

Need Beyond AM

The program supports digital transformation, productivity, and regulatory compliance objectives beyond traditional asset management.

Past Costs for Similar Projects

Past costs for similar enterprise software upgrade projects undertaken by LUI have been considered in developing the capital cost estimate for this investment. The forecasted cost reflects recent experience with ERP modernization initiatives, adjusted for current vendor pricing, implementation complexity, and forecast cost escalation.

NWS Screening

Non-wires alternatives are not applicable, as the program addresses enterprise systems rather than distribution capacity or load-serving constraints.

Software Upgrades (GIS) – Material Investment Narrative (2027–2031)

A. General Information on the Project/Program

Project Code: GP-003	**2022-2026 Cost ($M):** $0.00M	**2027-2031 Cost ($M):** $0.12M
Segments: Information systems		
Investment Category: General Plant		
Trigger Driver: Vendor end-of-support, Cybersecurity and operational risk		
Outcomes: Enhanced real-time situational awareness, improved asset management, improved outage management, and seamless smart mapping integration		

Need for the Investment

The GIS Platform Upgrade Program supports the transition of LUI's Geographic Information System (GIS) from the legacy Esri ArcMap 10.9 to ArcGIS Pro. This investment is driven by Esri's confirmed end-of-support for ArcMap by March 2028 as well as the growing operational limitations of the legacy platform, and the need to maintain a secure, reliable, and fully integrated geospatial environment.

Beyond the end-of-support trigger, the legacy ArcMap platform is increasingly incompatible with modern enterprise systems. Continued reliance on ArcMap will progressively limit LUI's ability to integrate GIS data with outage management systems (OMS), asset management workflows, and real-time operational tools.

ArcGIS Pro represents Esri's current-generation, fully supported desktop GIS platform. Migration to ArcGIS Pro enables LUI to leverage a modern service-oriented architecture, real-time data integration, enhanced smart mapping capabilities, and significantly improved utility network asset management.

Scope and Volume of Work

The scope of this program encompasses the full migration from ArcMap to ArcGIS Pro across LUI's GIS environment. Key work activities include:

- Software licensing transition from ArcMap 10.9 to ArcGIS Pro user types
- Data migration
- Integration with enterprise systems including outage management, asset management, and customer information systems
- Staff training and organizational change management
- Data quality validation and remediation
- System testing, parallel operation, and cutover management

Final scope and sequencing will be confirmed through detailed project planning and procurement, including assessment of third-party GIS application dependencies.

Key Timings

The GIS Platform Upgrade will be executed in 2027. The program will be phased to allow for risk mitigation, data migration and validation, system integration, and staff training. Detailed sequencing will be finalized through project planning, with migration activities prioritized to complete prior to end of support date.

Total Capital Expenditures (Including Contributions)

The total capital cost for the GIS Platform Upgrade Program is forecast at approximately $125k in 2027, reflecting ArcGIS Pro licensing, implementation and migration services, system integration, training, and change management costs. No capital contributions are anticipated based on current funding assumptions.

Economic Evaluation (DSC 3.2)

The economic evaluation for this program is centered around operational risk avoidance, cybersecurity risk reduction, and the operational efficiency and service quality improvements enabled by the ArcGIS Pro platform. Benefits are associated with avoidance of unmitigated cybersecurity vulnerabilities, improved GIS system reliability, enhanced integration with operational systems, and improved staff

Comparative Historical Expenditures

Cost assumptions for this program are consistent with comparable GIS migration initiatives undertaken by utilities of similar scale and reflect current Esri vendor pricing structures, implementation complexity, and forecast cost escalation.

Investment Priority

The GIS Platform Upgrade is prioritized within the 2027–2031 capital portfolio based on the firm vendor support end-date, the cybersecurity risk associated with operating unsupported software, and the operational importance of GIS to LUI's utility network management, field operations, and outage response. Priority is further supported by the growing incompatibility of ArcMap with current and future versions of ArcGIS Enterprise and integrated operational systems.

Alternatives Considered

1. **Deferral beyond 2028:** Continuing to operate ArcMap beyond the third-party extended support window was assessed and deemed unacceptable. Operating unsupported GIS software in a regulated utility environment exposes LUI to unmitigated cybersecurity vulnerabilities, potential data integrity risks, and growing incompatibility with enterprise systems. This option also risks stranded investment as ArcMap-based services and workflows become inoperable with newer ArcGIS Enterprise versions.

2. **Limited patching or workarounds:** Applying interim patches or workarounds to extend the useful life of the ArcMap environment was evaluated but found to be

ineffective. This approach would not address the fundamental platform incompatibility or cybersecurity exposure.

3. **Alternative GIS vendors:** Third-party GIS platforms were reviewed as potential alternatives. However, Esri ArcGIS Pro represents the industry-standard platform for utility GIS environments, with the deepest integration capability with utility network management, outage management, and asset management systems. Migrating to a non-Esri platform would introduce significantly higher implementation complexity, data migration risk, and integration costs, while forfeiting LUI's existing Esri licensing investments and institutional knowledge.

Benefit-Cost Analysis (Recommended Alternative)

The recommended alternative is a phased migration to ArcGIS Pro and, where operationally appropriate, adoption of the ArcGIS Utility Network data model. Benefits of this approach include:

- **Cybersecurity and risk mitigation:** Eliminating the exposure associated with operating an unsupported, unpatched GIS platform in a utility operational environment. ArcGIS Pro is actively developed and maintained by Esri, with ongoing security updates and compatibility with current enterprise operating environments.

- **Real-time data integration:** ArcGIS Pro's service-oriented architecture enables integration of real-time data feeds, This supports real-time situational awareness for field operations and network monitoring.

- **Smart mapping and visualization:** ArcGIS Pro provides advanced smart mapping capabilities, including dynamic symbology, real-time dashboards, and web-accessible mapping.

- **Improved asset management:** The ArcGIS Utility Network model provides a high-fidelity, rules-based representation of LUI's utility infrastructure, with built-in data quality validation. Advanced tracing, and asset lifecycle tracking capabilities support more informed capital planning, maintenance prioritization, and reporting.

- **Improved outage management:** ArcGIS Pro's Utility Network enables direct integration with outage management systems (OMS) and advanced distribution management systems (ADMS).

- **Operational continuity:** Completing the migration prior to the February 2028 extended support deadline ensures uninterrupted GIS operations and avoids the risk of system failure or incompatibility at a critical juncture.

Innovative Nature (If Applicable)

The program incorporates Esri's current-generation ArcGIS Pro platform and ArcGIS Utility Network which is a modern, service-oriented network data model that enables advanced utility network analysis, digital twin capabilities, and enterprise-wide GIS access.

Leave-to-Construct Requirements (If Applicable)

Not applicable.

B. Evaluation Criteria and Justification

Efficiency

Migration to ArcGIS Pro eliminates the manual workarounds and compatibility limitations associated with the legacy ArcMap platform. It enables enterprise-wide, real-time access to GIS data across desktop, web, and mobile environments which reduces duplication of effort and improving workflows across engineering, operations, and field crews.

Customer Value

Customers benefit directly through improved outage management capabilities through ability to more accurately identify affected customers and coordinate faster restoration. Integration between ArcGIS Pro and outage management systems supports more timely and accurate customer communications during service disruptions.

Reliability

ArcGIS Pro is Esri's fully supported platform ensuring ongoing compatibility with operating systems, cybersecurity standards, and enterprise system integrations. Eliminating dependency on an unsupported platform reduces the risk of system failure, data corruption, or integration breakdown. The Utility Network's built-in data quality validation and topology enforcement also improves the accuracy and integrity of LUI's spatial data.

Safety

Operating a GIS platform that no longer receives security patches or vendor support represents a material cybersecurity risk in a utility operational environment. Migration to ArcGIS Pro eliminates this exposure and ensures LUI's GIS environment remains current with cybersecurity standards. GIS data integrity also supports safe field operations by ensuring crews have accurate, up-to-date information on asset locations, network connectivity, and operating conditions.

Operations & Maintenance (O&M) Impacts / Trade-offs

Following implementation, the program is expected to reduce the ongoing IT support burden associated with maintaining legacy ArcMap services, managing compatibility workarounds, and manually compensating for platform limitations. Some transitional O&M cost increase may occur during the migration period, but long-term O&M costs are expected to stabilize at a level consistent with a modern, supported platform.

Evidence-Based Justification

This investment is supported by Esri's publicly confirmed end-of-support deadline, and the documented incompatibility of ArcMap services with current and future versions of ArcGIS Enterprise. Industry experience from comparable utility GIS migrations confirms the operational benefits of ArcGIS Pro and the Utility Network model in the areas of asset management, outage response, and enterprise integration.

Asset Management Linkage

The ArcGIS Utility Network provides a comprehensive, rules-based model of LUI's infrastructure, enabling improved asset lifecycle tracking, connectivity modeling, and integration with enterprise asset management systems. This supports more informed capital planning, condition-based maintenance prioritization.

Need Beyond AM

The program supports broader digital transformation objectives beyond traditional asset management, including real-time operational awareness, enterprise-wide GIS access, smart mapping, integration with outage and distribution management systems.

Past Costs for Similar Projects

Past costs for GIS licensing, implementation, and related IT infrastructure projects undertaken by LUI have been considered in developing the capital cost estimate for this investment. The forecasted cost reflects current Esri licensing structures, implementation complexity associated with Utility Network migration.

NWS Screening

Non-wires alternatives are not applicable, as this program addresses enterprise GIS software rather than distribution capacity or load-serving constraints.

Appendix 2-AA
Capital Projects Table

Net Capital/Gross Capital	Gross Capital

Projects	2022	2023	2024	2025	2026 Bridge Year	2027 Test Year	2028	2029	2030	2031
Reporting Basis					**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access										
CUSTOMER DRIVEN - TESLA SUPERCHARGER - CT PARKING	65,458									
NEW SERVICES	56,725	67,147	66,595	94,109	70,000	72,100	74,263	76,118	78,022	79,975
CUSTOMER DRIVEN - TRIBUTE HOMES - NEW POLE LINE	87,423									
SEAL EXPIRY METER REPLACE	128,900	378,527	92,736	122,236	70,000					
CUSTOMER DRIVEN - EAST VILLAGE - BGS HOMES		220,010								
CUSTOMER DRIVEN - FOXTAIL RIDGE		161,495								
CUSTOMER DRIVEN - COAST GUARD - SERVICE UPGRADE		63,340								
CUSTOMER DRIVEN - BATTERY STORAGE - JEBCO		55,377								
NEW 28KV STATION - VICTORIA STN 2		2,535,311								
F1/F7 FEEDER TIE-SWITCH INSTALLATION			57,429							
CUSTOMER DRIVEN - RONDEAU SUBDIVISION - TRIBUTE			1,054,975							
CUSTOMER DRIVEN - GATES OF CAMELOT PH 5			373,549							
CUSTOMER DRIVEN - DENSMORE MEADOWS SUBDIVISION			629,130							
CUSTOMER DRIVEN - NEW AMHERST - STAGE 2 PHASE 1			342,875							
CUSTOMER DRIVEN - DODGE ST - NEW POLE LINE			87,883							
CUSTOMER DRIVEN - 755 DIVISION ST - NET METER				57,534						
POLE REPLACEMENTS				129,374						
CUSTOMER DRIVEN - POLE LINE - DURHAM ST N COLB				342,332						
CUSTOMER DRIVEN - BROOK RD N				97,531						
CUSTOMER ECONOMIC EVALUATION ASSESSMENTS					500,000	515,000	530,450	543,700	557,300	571,250
COMMERCIAL SERVICES					360,000	370,800	381,924	391,464	401,256	411,300
KING ST SIDEWALK WIDENING					60,000					
VICTORIA STATION MS28-1 REFURBISHMENT					125,000					
AMI 2.0						263,721	408,948	415,988	397,369	416,685
System Access Gross Expenditures	338,506	3,481,206	2,705,171	843,116	1,185,000	1,221,621	1,395,585	1,427,270	1,433,947	1,479,210
System Access Capital Contributions	**419,929**	**764,807**	**2,227,701**	**649,760**	**790,000**	**782,800**	**806,284**	**826,424**	**847,096**	**868,300**
Sub-Total	-81,423	2,716,399	477,470	193,356	395,000	438,821	589,301	600,846	586,851	610,910
System Renewal										
ELGIN ST - BIRCHWOOD TO CHIPPING	349,023									
ROW 44/28kV - P73 TO BURNHAM ST	292,540									
POLE REPLACEMENTS	75,226	230,727			60,000	61,800	74,263	97,866	156,044	159,950
VICTORIA ST. STATION TO ONT ST	405,156									
KERR ROW - VIC STN TO DIVISION	209,116									
BROOK F5 NEW FEEDER	347,351									
UNDERGROUND MISCELLANEOUS	64,148	97,783		115,780	55,000	58,710	60,471	61,982	63,532	65,123
OVERHEAD MISCELLANOUS	91,136	60,851	91,508	226,014	75,000	77,250	79,568	81,555	83,595	85,688
DELTA TO WYE CONVERSIONS	63,609									
DURHAM ST - DURHAM STN TO KING		478,410								
KING ST POLE LINE - JEBCO		239,022								
VICTORIA ST - STN TO KING ST		187,821								
LAKEFRONT DEC STORM		122,297								
ELGIN ST - CHIPPING TO ONTARIO			446,477							
KERR ST - BURNHAM ST TO POW			414,215							
BUCK/GEORGE - UNI TO KING - 28KV			180,442							

BROOK N TO D'ARCY (ELGIN)				150,000						
ELGIN - ONTARIO TO WILLIAM				504,874						
ENGINEERING DESIGN AND SUPPORT STAFF				89,578	55,000	77,250	79,568	81,555	83,595	85,688
DELTA-WYE CONVERSIONS							53,045	54,370	111,460	114,250
PARLIAMENT 25-89 (OH Rebuild)					190,000					
3PH PAD TRANSFORMER REPLACEMENTS						72,100	74,263	76,118	78,022	79,975
BOUNDARY - ELGIN TO KERR							249,312			
1Ph PAD TRANSFORMER REPLACEMENTS							63,654	65,244	66,876	91,400
ELGIN - WILLLIAN TO STRATHY								217,480		
ELGIN - STRATHY TO NEW AMHERST									111,460	304,475
INDUSRIAL RD REBUILD									111,460	102,825
System Renewal Gross Expenditures	1,897,305	1,416,913	1,132,641	1,086,246	435,000	347,110	734,144	736,170	866,044	1,089,374
System Renewal Capital Contributions	**0**	**0**	**12,500**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Sub-Total	1,897,305	1,416,913	1,120,141	1,086,246	435,000	347,110	734,144	736,170	866,044	1,089,374
System Service										
OMS		509,510								
RELIABILITY IMPROVEMENT PROGRAM			72,474							
BROOK N TO D'ARCY (ELGIN)				558,943						
SPRING - FURNACE TO ORR (4.16 TO 28KV CONVERSION)					241,500	293,550				
COVERT - DIVISION TO GEORGE (4KV TO 28KV CONVERSION)					295,000					
MISC 28KV CONVERSIONS (SPOT REPLACEMENTS)					100,000	51,500				
GIS IMPROVEMENTS					60,000					
ADVANCED LATERAL PROTECTION (TRIPSAVERS)						105,000				
DISTRIBUTION SYSTEM AUTOMATION						606,686	624,888	548,067	111,460	
F7 EXPANSION (BOUNDARY TO NEW AMHERST) + 4.16KV DECOMM									312,088	434,150
System Service Gross Expenditures	0	509,510	72,474	558,943	696,500	1,056,736	624,888	548,067	423,548	434,150
System Service Capital Contributions	**0**	**0**	**0**	**0**	**0**	**202,008**	**202,008**	**202,008**	**0**	**0**
Sub-Total	0	509,510	72,474	558,943	696,500	854,728	422,880	346,059	423,548	434,150
General Plant										
FLEET - PICKUP TRUCK AND BUCKET TRUCK		53,971		572,550	70,000		63,654	90,177		
SOFTWARE UPGRADES (MISC)					54,563					
TOOLS					59,000					
FACILITIES - BUILDINGS						61,800				
SOFTWARE UPGRADES (ERP)						208,575	53,045			
SOFTWARE UPGRADES (GIS)						125,000				
SOFTWARE UPGRADES (CIS)							159,134	198,994	203,972	
General Plant Gross Expenditures	0	53,971	0	572,550	183,563	395,375	275,833	289,171	203,972	0
General Plant Capital Contributions	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**	**0**
Sub-Total	0	53,971	0	572,550	183,563	395,375	275,833	289,171	203,972	0
Miscellaneous	303,806	432,842	552,118	353,475	129,100	237,095	133,143	184,859	125,393	128,532
Total	**2,119,689**	**5,129,635**	**2,222,203**	**2,764,570**	**1,839,163**	**2,273,129**	**2,155,301**	**2,157,105**	**2,205,808**	**2,262,966**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*										
Total	**2,119,689**	**5,129,635**	**2,222,203**	**2,764,570**	**1,839,163**	**2,273,129**	**2,155,301**	**2,157,105**	**2,205,808**	**2,262,966**

Notes:

1 Please provide a breakdown of the major components of each capital project undertaken in each year. Please ensure that all projects below the materiality threshold are included in the miscellaneous line. Add more projects as required.

2 The applicant should group projects appropriately and avoid presentations that result in classification of significant components of the capital budget in the miscellaneous category.