Exhibit 2

Rate Base

TABLE OF CONTENTS

1.0 RATE BASE

1.1 RATE BASE OVERVIEW

The rate base used for the purpose of calculating the revenue requirement used in this Application follows *Chapter 2 of the Filing Requirements for Electricity Distribution Applications* issued by the Ontario Energy Board ("**Board**") on June 24, 2021 (the "**Filing Requirements**"). In accordance with the Filing Requirements, E.L.K. has calculated the rate base as an average of the net capital balances at the beginning and the end of the 2022 Test Year plus a working capital allowance, which is 7.5% of the sum of the cost of power and controllable expenses.

At this time, E.L.K. has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this application using the default value of 7.5%. E.L.K. was not previously directed by the OEB to undertake a lead/lag study.

E.L.K. converted to Modified International Financial Reporting Standards (MIFRS) on January 1, 2015 and has prepared this application under MIFRS.

E.L.K. has reported PP&E under historical acquisition costs for regulatory purposes in accordance with Article 315 in the Accounting Procedures Handbook. E.L.K. adopted a change in capitalization and useful lives policies as described in Exhibit 4 as part of E.L.K.'s 2012 Cost of Service Application (EB-2011-0099).

Net capital assets include in service assets that are associated with activities that enable the conveyance of electricity for distribution purposes minus accumulated depreciation and contributed capital from third parties. For purposes of this Exhibit, distribution assets refer to those assets that are most directly related to the distribution system, such as poles, overhead and underground lines, and transformers. General plant refers to assets that support the operation of the distribution system such, as computer hardware and software, vehicles, buildings, equipment. Capital assets include property, plant and equipment ("**PP&E**") and intangible assets; these are referred to as "capital" or "fixed" assets throughout this evidence. The rate base calculation excludes any non-distribution assets. E.L.K. has not applied for, nor received, any Incremental

Capital Module ("**ICM**") adjustments. Controllable expenses include operations and maintenance, billing and collecting, and administration expenses.

This exhibit will compare 2012 Board Approved data and historical data since 2016 with the 2021 Bridge Year and 2022 Test Year. Complete historical rate base data from E.L.K.'s last approved test year 2012 to 2015 Actual is provided in EB-2016-0066, Exhibit 2.

E.L.K. has calculated its 2022 Test Year rate base to be $13,820,951. This rate base is used to determine the proposed Revenue Requirement found at Exhibit 6. Table 2-1 illustrates E.L.K.'s Rate Base Calculations for the Test Year.

Table 2-1: 2022 Test Year Rate Base

	2022
Net Capital Assets in Service	
Opening Balance	11,155,991
Ending Balance	11,996,180
Average Balance	**11,576,086**
Working Capital Allowance	2,244,865
Total Rate Base	**13,820,951**

Expenses for Working Capital	2022
Eligible Distribution Expenses	
Distribution - Operation	521,943
Distribution - Maintenance	924,630
Billing & Collecting	721,707
Community Relations	11,537
Administrative & General Expenses	1,346,008
Donations - LEAP	5,617
Taxes other than Income Taxes	20,000
Total Eligible Distribution Expenses	3,551,441
Power Supply Expenses	26,380,096
Total Expenses for Working Capital	29,931,537
Working Capital Factor	7.50%
Total Working Capital Allowance	2,244,865

E.L.K. has provided its rate base calculations for OEB Approved 2012, 2016 to 2020 Actual, 2021 Bridge Year and 2022 Test Year in Table 2-2 below:

Table 2-2 - Summary of Rate Base

	2012 Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Net Capital Assets in Service								
Opening Balance	9,211,176	8,656,911	8,587,550	8,813,259	9,379,210	9,392,454	10,316,027	11,155,991
Ending Balance	8,784,978	8,587,550	8,813,259	9,379,210	9,392,454	10,316,027	11,155,991	11,996,180
Average Balance	8,998,077	8,622,231	8,700,405	9,096,235	9,385,832	9,854,241	10,736,009	11,576,086
WC Allowance	3,326,515	2,493,360	2,522,894	2,395,181	2,555,180	2,828,528	2,230,724	2,244,865
Total Rate Base	12,324,592	11,115,591	11,223,299	11,491,416	11,941,012	12,682,768	12,966,733	13,820,951

The Rate Base for the 2022 Test Year has been forecasted to increase $854,218 (6.6%) over the 2021 Bridge Year. Furthermore, the Rate Base for the 2022 Test Year is $1,496,359 (12.1%) higher than the 2012 Board Approved Rate Base. The reasons for the variance between the 2022 Test Year and 2012 OEB Approved is mainly attributed to:

- The decrease in the working capital allowance rate has reduced the Rate Base. The decrease is mainly attributed to the decrease in the working capital rate of 7.5% from 12% as approved during E.L.K.'s 2012 COS.

- Annual changes in cost of power and increases in OM&A expenses. E.L.K. has forecast an increase in Power Supply Expenses and eligible distribution expenses since the last Board Approved Rate.

- The average net capital asset in service has also increased. The main drivers behind this are the decrease in useful lives which results in a decrease in depreciation expense as well as the increased investment back into the distribution system.

E.L.K. has provided a summary of its calculations of the cost of power and controllable expenses used in the calculations for determining working capital for the years 2016 Actual, 2017 Actual, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Bridge Year and 2022 Test Year in Table 2-3 below. Further details of E.L.K.'s calculation of its cost of power calculations are provided in Table 2-18 and Table 2-19.

Table 2-3 - Summary of Working Capital Calculation

Expenses for Working Capital	2012 Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Eligible Distribution Expenses								
Operation	291,000	284,289	284,584	273,238	311,700	284,999	387,414	521,943
Maintenance	455,000	647,045	626,094	696,284	774,109	578,700	804,383	924,630
Billing & Collecting	775,064	605,236	635,071	719,649	669,849	551,626	678,651	721,707
Community Relations	10,000	7,585	3,497	20,967	6,065	3,438	10,000	11,537
Administrative & General Expenses	917,908	996,936	1,094,108	937,336	1,104,987	1,018,894	1,329,657	1,346,008
Donations - LEAP	38	5,179	5,179	5,179	5,179	10,179	5,179	5,617
Taxes other than Income Taxes	23,000	15,346	16,905	17,768	18,791	19,180	20,000	20,000
Total Eligible Distribution Expenses	2,472,009	2,561,616	2,665,438	2,670,420	2,890,679	2,467,017	3,235,284	3,551,441
Power Supply Expenses	25,248,949	30,683,184	30,973,150	29,265,330	31,178,390	35,246,686	26,507,696	26,380,096
Total Expenses for Working Capital	27,720,959	33,244,800	33,638,588	31,935,750	34,069,069	37,713,703	29,742,980	29,931,537
Working Capital Factor	12.0%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital Allowance	3,326,515	2,493,360	2,522,894	2,395,181	2,555,180	2,828,528	2,230,724	2,244,865

1.2 VARIANCE ANALYSIS OF RATE BASE

The following Table 2-4 and Table 2-5 set out E.L.K.'s rate base and working capital calculations for the 2022 Test Year, 2021 Bridge Year, and 2020 Actuals and the following variances:

- 2021 Bridge Year against 2020 Actual; and
- 2022 Test Year against 2021 Bridge Year;

E.L.K.'s materiality threshold is $50,000.

Table 2-4 – 2020 Actual vs. 2021 Bridge Year

	2020 Actual	2021 Bridge Year	Variance	%
Net Capital Assets in Service				
Opening Balance	9,392,454	10,316,027	923,573	9.8%
Ending Balance	10,316,027	11,155,991	839,964	8.1%
Average Balance	9,854,241	10,736,009	881,769	8.9%
Working Capital Allowance	2,828,528	2,230,724	-597,804	-21.1%
Total Rate Base	12,682,768	12,966,733	283,964	2.2%

The total projected Rate Base in the 2021 Bridge Year of $12,966,733 is $283,964 or 2.2% higher than 2020.

The main reason for the difference is power supply expense was significantly lower than projected. This was impacted by the overall weather conditions in 2021. Further OM & A was lower than projected. The actual average balance of net capital assets is lower based on significant contributions and grants.

Table 2-5 – 2021 Bridge Year vs. 2022 Test Year

	2021 Bridge Year	2022 Test Year	Variance	%
Net Capital Assets in Service				
Opening Balance	10,316,027	11,155,991	839,964	8.1%
Ending Balance	11,155,991	11,996,180	840,189	7.5%
Average Balance	10,736,009	11,576,086	840,077	7.8%
Working Capital Allowance	2,230,724	2,244,865	14,142	0.6%
Total Rate Base	12,966,733	13,820,951	854,218	6.6%

The total projected Rate Base in the 2022 Test Year of $13,820,951 is $854,218 or 6.6% higher than the 2021 Bridge Year.

The main reason for the difference is due to COVID 19 supply chain issues and staff turnover in critical positions in 2021 has constrained the organization's ability to deliver its projected programs for 2021. Lack of materials/equipment being delivered in 2021 in normal historical timelines and significant delays are hampering scheduled program activities. The Operations Manager and CFO left the organization in mid-year 2021 and this has caused a significant strain. .

1.3 FIXED ASSET CONTINUITY SCHEDULES

Table 2-6 through Table 2-12 are Board Appendix 2-BA and provide the Fixed Asset Continuity Schedules, for each of 2016 Actual, 2017 Actual, 2018 Actual, 2019 Actual, 2020 2021 Bridge Year, and 2022 Test Year.

These schedules present a continuity schedule of its investment in capital assets, the associated accumulated amortization and the net book value for each Capital USoA account.

Table 2-6 - Fixed Asset Continuity Schedule as at December 31, 2016, MIFRS

Accounting Standard MIFRS
Year 2016

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 259,251	$ 35,042	$ -	$ 294,293	-$ 256,883	-$ 7,409	$ -	-$ 264,292	$ 30,001
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,200	-$ 62	$ -	-$ 141,262	$ 836
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,087,163	$ 46,855	$ -	$ 1,134,018	-$ 293,405	-$ 22,135	$ -	-$ 315,540	$ 818,478
47	1835	Overhead Conductors & Devices	$ 6,502,230	$ 22,724	$ -	$ 6,524,954	-$ 4,664,708	-$ 37,947	$ -	-$ 4,702,655	$ 1,822,299
47	1840	Underground Conduit	$ 2,216,428	$ 208,657	$ -	$ 2,425,085	-$ 398,749	-$ 43,771	$ -	-$ 442,520	$ 1,982,565
47	1845	Underground Conductors & Devices	$ 8,323,875	$ 250,831	$ -	$ 8,574,706	-$ 5,115,256	-$ 111,762	$ -	-$ 5,227,018	$ 3,347,688
47	1850	Line Transformers	$ 6,471,488	$ 134,109	$ -	$ 6,605,597	-$ 3,765,907	-$ 90,091	$ -	-$ 3,855,999	$ 2,749,599
47	1855	Services (Overhead & Underground)	$ 1,031,062	$ 82,215	$ -	$ 1,113,277	-$ 277,891	-$ 44,385	$ -	-$ 322,276	$ 791,001
47	1860	Meters	$ 432,821	$ 20,633	$ -	$ 453,454	-$ 112,640	-$ 38,690	$ -	-$ 151,330	$ 302,124
47	1860	Meters (Smart Meters)	$ 1,324,006	$ 981	$ -	$ 1,324,987	-$ 391,236	-$ 132,837	$ -	-$ 524,072	$ 800,915
N/A	1905	Land	$ 171,765	$ -	-$ 89,366	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 665,443	$ -	-$ 249,155	$ 416,288	-$ 390,058	-$ 12,981	$ 151,974	-$ 251,066	$ 165,222
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 252,992	$ 40,795	$ -	$ 293,787	-$ 230,924	-$ 6,891	$ -	-$ 237,815	$ 55,972
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 403,764	$ 24,058	$ -	$ 427,822	-$ 376,408	-$ 11,264	$ -	-$ 387,672	$ 40,150
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 357,952	$ 26,310	$ -	$ 384,262	-$ 180,008	-$ 36,852	$ -	-$ 216,860	$ 167,402
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 385,936	$ 5,647	$ -	$ 391,583	-$ 353,753	-$ 8,859	$ -	-$ 362,612	$ 28,970
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,872	$ -	$ -	$ 36,872	-$ 29,113	-$ 1,357	$ -	-$ 30,470	$ 6,403
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 6,342,546	-$ 438,399	$ -	-$ 6,780,945	$ 1,910,892	$ 264,022	$ -	$ 2,174,914	-$ 4,606,031
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 23,727,673**	**$ 460,458**	**-$ 338,521**	**$ 23,849,611**	**-$ 15,069,987**	**-$ 343,271**	**$ 151,974**	**-$ 15,261,284**	**$ 8,588,327**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 23,727,673**	**$ 460,458**	**-$ 338,521**	**$ 23,849,611**	**-$ 15,069,987**	**-$ 343,271**	**$ 151,974**	**-$ 15,261,284**	**$ 8,588,327**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 343,271**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 36,852
8		Stores Equipment	Stores Equipment	-$ 1,357
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 305,063

Table 2-7 - Fixed Asset Continuity Schedule as at December 31, 2017, MIFRS

Accounting Standard	MIFRS
Year	**2017**

		Cost				Accumulated Depreciation				
OEB Account [3]	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
1609	Capital Contributions Paid				$ -				$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 294,293	$ 2,438	$ -	$ 296,731	-$ 264,292	-$ 11,028	$ -	-$ 275,319	$ 21,412
1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
1808	Buildings				$ -				$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,262	-$ 62	$ -	-$ 141,324	$ 774
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,134,018	$ 46,122	$ -	$ 1,180,140	-$ 315,540	-$ 23,168	$ -	-$ 338,708	$ 841,431
1835	Overhead Conductors & Devices	$ 6,524,954	$ 19,879	$ -	$ 6,544,833	-$ 4,702,655	-$ 38,302	$ -	-$ 4,740,957	$ 1,803,875
1840	Underground Conduit	$ 2,425,085	$ 162,310	$ -	$ 2,587,395	-$ 442,520	-$ 47,481	$ -	-$ 490,001	$ 2,097,394
1845	Underground Conductors & Devices	$ 8,574,706	$ 176,062	$ -	$ 8,750,768	-$ 5,227,018	-$ 117,099	$ -	-$ 5,344,117	$ 3,406,651
1850	Line Transformers	$ 6,605,597	$ 203,708	$ -	$ 6,809,305	-$ 3,855,999	-$ 94,310	$ -	-$ 3,950,309	$ 2,858,996
1855	Services (Overhead & Underground)	$ 1,113,277	$ 142,218	$ -	$ 1,255,495	-$ 322,276	-$ 48,874	$ -	-$ 371,150	$ 884,346
1860	Meters	$ 453,454	$ 17,952	$ -	$ 471,406	-$ 151,330	-$ 39,773	$ -	-$ 191,103	$ 280,303
1860	Meters (Smart Meters)	$ 1,324,987	$ 19,499	$ -	$ 1,344,486	-$ 524,072	-$ 133,861	$ -	-$ 657,933	$ 686,553
1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
1908	Buildings & Fixtures	$ 416,288	$ -	$ -	$ 416,288	-$ 251,066	-$ 11,462	$ -	-$ 262,527	$ 153,760
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 293,787	$ 988	$ -	$ 294,775	-$ 237,815	-$ 8,207	$ -	-$ 246,022	$ 48,753
1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
1920	Computer Equipment - Hardware	$ 427,822	$ 1,406	$ -	$ 429,228	-$ 387,672	-$ 13,047	$ -	-$ 400,719	$ 28,509
1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
1930	Transportation Equipment	$ 384,262	$ 19,695	$ -	$ 403,957	-$ 216,860	-$ 28,814	$ -	-$ 245,674	$ 158,284
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 391,583	$ 3,513	$ -	$ 395,096	-$ 362,612	-$ 8,302	$ -	-$ 370,914	$ 24,181
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 36,872	$ -	$ -	$ 36,872	-$ 30,470	-$ 1,227	$ -	-$ 31,697	$ 5,176
1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Deferred Revenue[5]	-$ 6,780,945	-$ 242,709	$ -	-$ 7,023,654	$ 2,174,914	$ 277,644	$ -	$ 2,452,558	-$ 4,571,096
2005	Property Under Finance Lease[7]				$ -				$ -	$ -
	Sub-Total	**$ 23,849,611**	**$ 573,080**	**$ -**	**$ 24,422,691**	**-$ 15,261,284**	**-$ 347,372**	**$ -**	**-$ 15,608,656**	**$ 8,814,035**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 23,849,611**	**$ 573,080**	**$ -**	**$ 24,422,691**	**-$ 15,261,284**	**-$ 347,372**	**$ -**	**-$ 15,608,656**	**$ 8,814,035**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
	Total						**-$ 347,372**			

		Less: *Fully Allocated Depreciation*	
	Transportation	Transportation	-$ 28,814
	Stores Equipment	Stores Equipment	-$ 1,227
	Deferred Revenue	Deferred Revenue	
		Net Depreciation	-$ 317,331

Table 2-8 - Fixed Asset Continuity Schedule as at December 31, 2018, MIFRS

Accounting Standard	MIFRS
Year	**2018**

		Cost				**Accumulated Depreciation**				
OEB Account [3]	**Description** [3]	**Opening Balance**	**Additions** [4]	**Disposals** [6]	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals** [6]	**Closing Balance**	**Net Book Value**
1609	Capital Contributions Paid				$ -				$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 296,731	$ 3,882	$ -	$ 300,613	-$ 275,319	-$ 11,259	$ -	-$ 286,578	$ 14,035
1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
1808	Buildings				$ -				$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,324	-$ 62	$ -	-$ 141,386	$ 713
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,180,140	$ 49,147	$ -	$ 1,229,287	-$ 338,708	-$ 24,227	$ -	-$ 362,935	$ 866,352
1835	Overhead Conductors & Devices	$ 6,544,833	$ 27,148	$ -	$ 6,571,981	-$ 4,740,957	-$ 38,694	$ -	-$ 4,779,652	$ 1,792,329
1840	Underground Conduit	$ 2,587,395	$ 92,701	$ -	$ 2,680,096	-$ 490,001	-$ 50,031	$ -	-$ 540,032	$ 2,140,064
1845	Underground Conductors & Devices	$ 8,750,768	$ 222,982	$ -	$ 8,973,750	-$ 5,344,117	-$ 122,086	$ -	-$ 5,466,203	$ 3,507,548
1850	Line Transformers	$ 6,809,305	$ 433,855	$ -	$ 7,243,160	-$ 3,950,309	-$ 102,279	$ -	-$ 4,052,588	$ 3,190,572
1855	Services (Overhead & Underground)	$ 1,255,495	$ 152,918	$ -	$ 1,408,413	-$ 371,150	-$ 54,776	$ -	-$ 425,926	$ 982,487
1860	Meters	$ 471,406	$ 32,135	$ -	$ 503,541	-$ 191,103	-$ 41,357	$ -	-$ 232,459	$ 271,082
1860	Meters (Smart Meters)	$ 1,344,486	$ 60,301	$ -	$ 1,404,788	-$ 657,933	-$ 137,851	$ -	-$ 795,784	$ 609,004
1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
1908	Buildings & Fixtures	$ 416,288	$ 10,121	$ -	$ 426,409	-$ 262,527	-$ 11,563	$ -	-$ 274,090	$ 152,319
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 294,775	$ 2,805	$ -	$ 297,580	-$ 246,022	-$ 8,020	$ -	-$ 254,042	$ 43,538
1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
1920	Computer Equipment - Hardware	$ 429,228	$ 2,345	$ -	$ 431,572	-$ 400,719	-$ 12,741	$ -	-$ 413,460	$ 18,112
1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
1930	Transportation Equipment	$ 403,957	$ -	$ -	$ 403,957	-$ 245,674	-$ 29,470	$ -	-$ 275,144	$ 128,813
1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment	$ 395,096	$ 14,697	$ -	$ 409,793	-$ 370,914	-$ 6,644	$ -	-$ 377,559	$ 32,234
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment	$ 36,872	$ -	$ -	$ 36,872	-$ 31,697	-$ 1,227	$ -	-$ 32,923	$ 3,949
1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
2440	Deferred Revenue[5]	-$ 7,023,654	-$ 172,754	$ -	-$ 7,196,408	$ 2,452,558	$ 285,953	$ -	$ 2,738,511	-$ 4,457,897
2005	Property Under Finance Lease[7]				$ -				$ -	$ -
	Sub-Total	**$ 24,422,691**	**$ 932,284**	**$ -**	**$ 25,354,975**	**-$ 15,608,656**	**-$ 366,333**	**$ -**	**-$ 15,974,989**	**$ 9,379,986**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
	Total PP&E	**$ 24,422,691**	**$ 932,284**	**$ -**	**$ 25,354,975**	**-$ 15,608,656**	**-$ 366,333**	**$ -**	**-$ 15,974,989**	**$ 9,379,986**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
	Total						**-$ 366,333**			

		Less: *Fully Allocated Depreciation*	
	Transportation	Transportation	-$ 29,470
	Stores Equipment	Stores Equipment	-$ 1,227
	Deferred Revenue	Deferred Revenue	
		Net Depreciation	-$ 335,636

Table 2-9 - Fixed Asset Continuity Schedule as at December 31, 2019, MIFRS

Accounting Standard MIFRS
Year 2019

CCA Class 2	OEB Account 3	Description 3	Cost: Opening Balance	Cost: Additions 4	Cost: Disposals 6	Cost: Closing Balance	Accumulated Depreciation: Opening Balance	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals 6	Accumulated Depreciation: Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 300,613	$ 2,398	$ -	$ 303,011	-$ 286,578	-$ 10,284	$ -	-$ 296,862	$ 6,150
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,386	-$ 62	$ -	-$ 141,448	$ 651
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,229,287	$ 50,332	$ -	$ 1,279,619	-$ 362,935	-$ 25,332	$ -	-$ 388,267	$ 891,352
47	1835	Overhead Conductors & Devices	$ 6,571,981	$ 13,825	$ -	$ 6,585,806	-$ 4,779,652	-$ 39,036	$ -	-$ 4,818,687	$ 1,767,118
47	1840	Underground Conduit	$ 2,680,096	$ 144,442	$ -	$ 2,824,538	-$ 540,032	-$ 52,402	$ -	-$ 592,434	$ 2,232,104
47	1845	Underground Conductors & Devices	$ 8,973,750	$ 264,865	$ -	$ 9,238,616	-$ 5,466,203	-$ 128,184	$ -	-$ 5,594,387	$ 3,644,229
47	1850	Line Transformers	$ 7,243,160	$ 292,937	$ -	$ 7,536,097	-$ 4,052,588	-$ 111,295	$ -	-$ 4,163,883	$ 3,372,215
47	1855	Services (Overhead & Underground)	$ 1,408,413	$ 111,819	$ -	$ 1,520,232	-$ 425,926	-$ 60,071	$ -	-$ 485,997	$ 1,034,235
47	1860	Meters	$ 503,541	$ 19,699	$ -	$ 523,240	-$ 232,459	-$ 43,048	$ -	-$ 275,508	$ 247,732
47	1860	Meters (Smart Meters)	$ 1,404,788	$ 22,520	$ -	$ 1,427,308	-$ 795,784	-$ 141,992	$ -	-$ 937,775	$ 489,532
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 426,409	$ 6,477	$ -	$ 432,886	-$ 274,090	-$ 11,729	$ -	-$ 285,819	$ 147,067
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 297,580	$ 364	$ -	$ 297,944	-$ 254,042	-$ 7,811	$ -	-$ 261,852	$ 36,091
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 431,572	$ 10,346	$ -	$ 441,918	-$ 413,460	-$ 12,666	$ -	-$ 426,126	$ 15,792
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 403,957	$ 150,667	$ -	$ 554,624	-$ 275,144	-$ 32,826	$ -	-$ 307,970	$ 246,654
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 409,793	$ 3,326	$ -	$ 413,119	-$ 377,559	-$ 5,266	$ -	-$ 382,825	$ 30,294
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 36,872	$ 552	$ -	$ 37,425	-$ 32,923	-$ 1,254	$ -	-$ 34,178	$ 3,247
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	2440	Deferred Revenue 5	-$ 7,196,408	-$ 701,507	$ -	-$ 7,897,915	$ 2,738,511	$ 303,439	$ -	$ 3,041,950	-$ 4,855,965
	2005	Property Under Finance Lease 7				$ -				$ -	$ -
		Sub-Total	**$ 25,354,975**	**$ 393,062**	**$ -**	**$ 25,748,037**	**-$ 15,974,989**	**-$ 379,818**	**$ -**	**-$ 16,354,807**	**$ 9,393,230**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 25,354,975**	**$ 393,062**	**$ -**	**$ 25,748,037**	**-$ 15,974,989**	**-$ 379,818**	**$ -**	**-$ 16,354,807**	**$ 9,393,230**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable 6									
		Total						**-$ 379,818**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 32,826
8		Stores Equipment	Stores Equipment	-$ 1,254
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 345,738

Table 2-10 - Fixed Asset Continuity Schedule as at December 31, 2020, MIFRS

Accounting Standard	MIFRS
Year	**2020**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 303,011	$ 76,208	$ -	$ 379,219	-$ 296,862	-$ 16,593	$ -	-$ 313,455	$ 65,764
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,448	-$ 62	$ -	-$ 141,510	$ 589
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,279,619	$ 100,842	$ -	$ 1,380,461	-$ 388,267	-$ 27,012	$ -	-$ 415,279	$ 965,182
47	1835	Overhead Conductors & Devices	$ 6,585,806	$ 69,829	$ -	$ 6,655,634	-$ 4,818,687	-$ 39,733	$ -	-$ 4,858,420	$ 1,797,214
47	1840	Underground Conduit	$ 2,824,538	$ 256,790	$ -	$ 3,081,328	-$ 592,434	-$ 56,415	$ -	-$ 648,849	$ 2,432,479
47	1845	Underground Conductors & Devices	$ 9,238,616	$ 264,077	$ -	$ 9,502,693	-$ 5,594,387	-$ 134,796	$ -	-$ 5,729,183	$ 3,773,511
47	1850	Line Transformers	$ 7,536,097	$ 301,232	$ -	$ 7,837,330	-$ 4,163,883	-$ 118,580	$ -	-$ 4,282,462	$ 3,554,867
47	1855	Services (Overhead & Underground)	$ 1,520,232	$ 153,959	$ -	$ 1,674,191	-$ 485,997	-$ 65,387	$ -	-$ 551,383	$ 1,122,807
47	1860	Meters	$ 523,240	$ 15,185	$ -	$ 538,425	-$ 275,508	-$ 44,104	$ -	-$ 319,612	$ 218,813
47	1860	Meters (Smart Meters)	$ 1,427,308	$ 55,698	$ -	$ 1,483,006	-$ 937,775	-$ 39,626	$ -	-$ 977,402	$ 505,604
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 432,886	$ 22,278	$ -	$ 455,164	-$ 285,819	-$ 12,016	$ -	-$ 297,835	$ 157,329
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 297,944	$ 11,279	$ -	$ 309,223	-$ 261,852	-$ 7,097	$ -	-$ 268,949	$ 40,273
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 441,918	$ 21,162	$ -	$ 463,080	-$ 426,126	-$ 12,218	$ -	-$ 438,344	$ 24,737
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 554,624	$ 407,380	$ -	$ 962,004	-$ 307,970	-$ 52,592	$ -	-$ 360,562	$ 601,443
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 413,119	$ 1,008	$ -	$ 414,127	-$ 382,825	-$ 4,978	$ -	-$ 387,803	$ 26,325
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 37,425	$ 112	$ -	$ 37,537	-$ 34,178	-$ 726	$ -	-$ 34,904	$ 2,632
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 7,897,915	-$ 529,593	$ -	-$ 8,427,508	$ 3,041,950	$ 328,061	$ -	$ 3,370,010	-$ 5,057,498
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 25,748,037**	**$ 1,227,446**	**$ -**	**$ 26,975,483**	**-$ 16,354,807**	**-$ 303,873**	**$ -**	**-$ 16,658,680**	**$ 10,316,803**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 25,748,037**	**$ 1,227,446**	**$ -**	**$ 26,975,483**	**-$ 16,354,807**	**-$ 303,873**	**$ -**	**-$ 16,658,680**	**$ 10,316,803**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 303,873**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 52,592
8		Stores Equipment	Stores Equipment	-$ 726
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 250,555

Table 2-11- Fixed Asset Continuity Schedule as at December 31, 2021, MIFRS

Accounting Standard	MIFRS
Year	**2021**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 379,219	$ 45,000	$ -	$ 424,219	-$ 313,455	-$ 24,969	$ -	-$ 338,424	$ 85,795
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,510	-$ 62	$ -	-$ 141,572	$ 527
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,380,461	$ 301,000	$ -	$ 1,681,461	-$ 415,279	-$ 31,476	$ -	-$ 446,755	$ 1,234,706
47	1835	Overhead Conductors & Devices	$ 6,655,634	$ 47,000	$ -	$ 6,702,634	-$ 4,858,420	-$ 40,706	$ -	-$ 4,899,126	$ 1,803,508
47	1840	Underground Conduit	$ 3,081,328	$ 211,000	$ -	$ 3,292,328	-$ 648,849	-$ 61,093	$ -	-$ 709,941	$ 2,582,387
47	1845	Underground Conductors & Devices	$ 9,502,693	$ 209,000	$ -	$ 9,711,693	-$ 5,729,183	-$ 140,709	$ -	-$ 5,869,892	$ 3,841,801
47	1850	Line Transformers	$ 7,837,330	$ 517,000	$ -	$ 8,354,330	-$ 4,282,462	-$ 128,632	$ -	-$ 4,411,094	$ 3,943,236
47	1855	Services (Overhead & Underground)	$ 1,674,191	$ 168,000	$ -	$ 1,842,191	-$ 551,383	-$ 71,826	$ -	-$ 623,209	$ 1,218,981
47	1860	Meters	$ 538,425	$ 21,000	$ -	$ 559,425	-$ 319,612	-$ 41,678	$ -	-$ 361,289	$ 198,136
47	1860	Meters (Smart Meters)	$ 1,483,006	$ 35,000	$ -	$ 1,518,006	-$ 977,402	-$ 24,821	$ -	-$ 1,002,223	$ 515,783
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 455,164	$ 2,000	$ -	$ 457,164	-$ 297,835	-$ 12,259	$ -	-$ 310,094	$ 147,070
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 309,223	$ 2,000	$ -	$ 311,223	-$ 268,949	-$ 6,731	$ -	-$ 275,681	$ 35,542
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 463,080	$ 5,000	$ -	$ 468,080	-$ 438,344	-$ 9,957	$ -	-$ 448,301	$ 19,779
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 962,004	$ 45,000	$ -	$ 1,007,004	-$ 360,562	-$ 67,098	$ -	-$ 427,660	$ 579,345
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 414,127	$ 20,000	$ -	$ 434,127	-$ 387,803	-$ 5,909	$ -	-$ 393,712	$ 40,415
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 37,537	$ -	$ -	$ 37,537	-$ 34,904	-$ 171	$ -	-$ 35,075	$ 2,462
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 8,427,508	-$ 467,951	$ -	-$ 8,895,459	$ 3,370,010	$ 348,011	$ -	$ 3,718,022	-$ 5,177,437
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 26,975,483**	**$ 1,160,049**	**$ -**	**$ 28,135,532**	**-$ 16,658,680**	**-$ 320,085**	**$ -**	**-$ 16,978,765**	**$ 11,156,767**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 26,975,483**	**$ 1,160,049**	**$ -**	**$ 28,135,532**	**-$ 16,658,680**	**-$ 320,085**	**$ -**	**-$ 16,978,765**	**$ 11,156,767**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 320,085**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 67,098
8		Stores Equipment	Stores Equipment	-$ 171
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 252,817

Table 2-12 - Fixed Asset Continuity Schedule as at December 31, 2022, MIFRS

Accounting Standard MIFRS
Year 2022

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance	Additions [4]	Disposals [6]	Closing Balance	Opening Balance	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 424,219	$ 8,000	$ -	$ 432,219	-$ 338,424	-$ 26,541	$ -	-$ 364,965	$ 67,254
CEC	1612	Land Rights (Formally known as Account 1906)	$ 2,945	$ -	$ -	$ 2,945	-$ 2,725	$ -	$ -	-$ 2,725	$ 220
N/A	1805	Land	$ 2,112	$ -	$ -	$ 2,112	$ -	$ -	$ -	$ -	$ 2,112
47	1808	Buildings				$ -				$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 142,098	$ -	$ -	$ 142,098	-$ 141,572	-$ 62	$ -	-$ 141,634	$ 465
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,681,461	$ 213,000	$ -	$ 1,894,461	-$ 446,755	-$ 37,168	$ -	-$ 483,922	$ 1,410,539
47	1835	Overhead Conductors & Devices	$ 6,702,634	$ 54,000	$ -	$ 6,756,634	-$ 4,899,126	-$ 41,548	$ -	-$ 4,940,674	$ 1,815,960
47	1840	Underground Conduit	$ 3,292,328	$ 200,000	$ -	$ 3,492,328	-$ 709,941	-$ 65,203	$ -	-$ 775,144	$ 2,717,184
47	1845	Underground Conductors & Devices	$ 9,711,693	$ 200,000	$ -	$ 9,911,693	-$ 5,869,892	-$ 145,822	$ -	-$ 6,015,714	$ 3,895,980
47	1850	Line Transformers	$ 8,354,330	$ 335,000	$ -	$ 8,689,330	-$ 4,411,094	-$ 139,119	$ -	-$ 4,550,213	$ 4,139,117
47	1855	Services (Overhead & Underground)	$ 1,842,191	$ 180,000	$ -	$ 2,022,191	-$ 623,209	-$ 78,786	$ -	-$ 701,995	$ 1,320,196
47	1860	Meters	$ 559,425	$ 12,000	$ -	$ 571,425	-$ 361,289	-$ 24,881	$ -	-$ 386,170	$ 185,255
47	1860	Meters (Smart Meters)	$ 1,518,006	$ 21,000	$ -	$ 1,539,006	-$ 1,002,223	-$ 26,122	$ -	-$ 1,028,345	$ 510,661
N/A	1905	Land	$ 82,399	$ -	$ -	$ 82,399	$ -	$ -	$ -	$ -	$ 82,399
47	1908	Buildings & Fixtures	$ 457,164	$ 2,000	$ -	$ 459,164	-$ 310,094	-$ 12,300	$ -	-$ 322,394	$ 136,770
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 311,223	$ 2,000	$ -	$ 313,223	-$ 275,681	-$ 6,929	$ -	-$ 282,610	$ 30,613
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 468,080	$ 27,000	$ -	$ 495,080	-$ 448,301	-$ 10,611	$ -	-$ 458,912	$ 36,168
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -				$ -	$ -
10	1930	Transportation Equipment	$ 1,007,004	$ 370,000	$ -	$ 1,377,004	-$ 427,660	-$ 69,955	$ -	-$ 497,615	$ 879,390
8	1935	Stores Equipment	$ -	$ -	$ -	$ -	$ -	-$ -	$ -	$ -	$ -
8	1940	Tools, Shop & Garage Equipment	$ 434,127	$ 10,000	$ -	$ 444,127	-$ 393,712	-$ 7,371	$ -	-$ 401,083	$ 43,044
8	1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 37,537	$ -	$ -	$ 37,537	-$ 35,075	-$ 171	$ -	-$ 35,245	$ 2,291
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ 15	$ -	$ -	$ 15	-$ 15	$ -	$ -	-$ 15	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 8,895,459	-$ 467,951	$ -	-$ 9,363,411	$ 3,718,022	$ 366,730	$ -	$ 4,084,751	-$ 5,278,659
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 28,135,532**	**$ 1,166,049**	**$ -**	**$ 29,301,581**	**-$ 16,978,765**	**-$ 325,859**	**$ -**	**-$ 17,304,624**	**$ 11,996,956**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 28,135,532**	**$ 1,166,049**	**$ -**	**$ 29,301,581**	**-$ 16,978,765**	**-$ 325,859**	**$ -**	**-$ 17,304,624**	**$ 11,996,956**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 325,859**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 69,955
8		Stores Equipment	Stores Equipment	-$ 171
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	-$ 255,733

2.0 GROSS ASSETS – PROPERTY PLANT AND EQUIPMENT AND ACCUMULATED DEPRECIATION

2.1 BREAKDOWN BY FUNCTION

Table 2-13 below categorizes E.L.K.'s assets into three categories; distribution plant, general plant, contributions and grants. In accordance with the Uniform System of Accounts ("USoA"), E.L.K. has included gross assets as follows:

- Distribution plant asset accounts include USoA 1805 to 1860 - this account includes assets such as substation equipment, poles, wires, transformers and meters;
- General plant asset accounts include USoA 1905 to 1990 and USoA 1611 - this account includes assets such as buildings, computer software and hardware, transportation equipment, and tools;
- Contributions and grants includes USoA account 1995 – this account includes all contributions in aid of capital that E.L.K. has received or forecasted to be received as per the Distribution System Code ("**DSC**"); and

Table 2-13 – Gross Asset Breakdown by Function

Description	2012 Board Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
Distribution Plant	24,682,050	27,916,787	28,694,164	29,623,633	30,619,446	31,688,472	33,051,778	34,413,778
General Plant	4,011,536	2,433,601	2,344,287	2,375,231	2,479,221	2,836,000	3,165,214	3,434,214
Contributions and Grants	-4,195,546	-6,561,746	-6,902,300	-7,110,031	-7,547,161	-8,162,711	-8,661,484	-9,129,435
Total	**24,498,040**	**23,788,642**	**24,136,151**	**24,888,833**	**25,551,506**	**26,361,760**	**27,555,508**	**28,718,556**

2.2 DETAILED BREAKDOWN BY MAJOR PLANT ACCOUNT

Table 2-14 below provides a detailed breakdown by major plant account for each functionalized plant item. Each plant item is accompanied by a description in accordance with the Board's USoA, including the 2022 Test Year. E.L.K. has also included a breakdown of accumulated amortization in the same format in Table 2-15.

1 **Table 2-14 - Gross Assets - Detailed Breakdown by Major Plant Function**

2 ***2012 Board Approved and 2016 Actual to 2022 Test Year***

USoA	Description	2012 Board Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
1805	Land	2,112	2,112	2,112	2,112	2,112	2,112	2,112	2,112
1820	Distribution Station Equipment - Normally Primary below 50 kV	142,098	142,098	142,098	142,098	142,098	142,098	142,098	142,098
1830	Poles, Towers and Fixtures	899,356	1,110,591	1,157,079	1,204,713	1,254,453	1,330,040	1,530,961	1,787,961
1835	Overhead Conductors and Devices	6,298,532	6,513,592	6,534,894	6,558,407	6,578,893	6,620,720	6,679,134	6,729,634
1840	Underground Conduit	1,341,878	2,320,756	2,506,240	2,633,745	2,752,317	2,952,933	3,186,828	3,392,328
1845	Underground Conductors and Devices	7,469,710	8,449,291	8,662,737	8,862,259	9,106,183	9,370,655	9,607,193	9,811,693
1850	Line Transformers	5,689,308	6,443,974	6,577,633	6,849,830	7,167,244	7,429,608	7,811,041	8,211,541
1851	Line Transformers - Pad Mounted Switchgear	-	11,213	19,914	31,548	40,958	45,378	47,018	48,518
1852	Line Transformers - UG Foundations and Vaults	-	83,356	109,904	144,855	181,427	211,728	237,771	261,771
1855	Services	741,071	1,072,170	1,184,386	1,331,954	1,464,322	1,597,211	1,758,191	1,932,191
1860	Meters	2,097,985	-	-	-	-	-	-	-
1861	Meters- Residential SM	-	1,324,497	1,334,737	1,374,637	1,416,048	1,455,157	1,500,506	1,528,506
1862	Meters- Industrial/ Commercial	-	326,187	332,014	339,212	346,329	355,406	372,350	387,350
1863	Meters- Wholesale	-	5,245	14,289	30,184	48,559	55,851	55,851	55,851
1864	Meters- CT's & PT's	-	111,705	116,127	118,077	118,502	119,576	120,724	122,224
1905	Land	171,765	127,082	82,399	82,399	82,399	82,399	82,399	82,399
1906	Land Rights	2,945	2,945	2,945	2,945	2,945	2,945	2,945	2,945
1908	Buildings and Fixtures	669,090	540,865	416,288	421,348	429,647	444,025	456,164	458,164
1915	Office Furniture and Equipment	244,159	273,389	294,281	296,177	297,762	303,583	310,223	312,223
1920	Computer Equipment - Hardware	363,468	415,793	428,525	430,400	436,745	452,499	465,580	481,580
1925	Computer Software	266,146	276,772	295,512	298,672	301,812	341,115	401,719	428,219
1930	Transportation Equipment	1,886,565	-	-	-	-	-	-	-
1931	Transportation Equipment- Heavy Vehicle	-	116,061	125,909	135,756	191,131	450,196	658,886	848,886
1932	Transportation Equipment- Light Vehicle	-	184,334	197,489	197,489	217,448	237,406	254,906	272,406
1933	Transportation Equipment- Underground	-	70,712	70,712	70,712	70,712	70,712	70,712	70,712
1940	Tools, Shop and Garage Equipment	371,567	388,759	393,339	402,444	411,456	413,623	424,127	439,127
1955	Communication Equipment	35,831	36,872	36,872	36,872	37,149	37,481	37,537	37,537
1985	Sentinel Lighting Rentals	-	15	15	15	15	15	15	15
1995	Contributions and Grants	-4,195,546	-6,561,746	-6,902,300	-7,110,031	-7,547,161	-8,162,711	-8,661,484	-9,129,435
Total Gross Assets		**24,498,040**	**23,788,642**	**24,136,151**	**24,888,833**	**25,551,506**	**26,361,760**	**27,555,508**	**28,718,556**

1 **Table 2-15 – Accumulated Amortization - Detailed Breakdown by Major Plant Function**

2 **2012 Board Approved and 2016 Actual to 2022 Test Year**

USoA	Description	2012 Board Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
1805	Land	-	-	-	-	-	-	-	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	140,983	141,231	141,293	141,355	141,417	141,479	141,541	141,603
1830	Poles, Towers and Fixtures	215,602	304,472	327,124	350,822	375,601	401,773	431,017	465,338
1835	Overhead Conductors and Devices	4,429,828	4,684,458	4,722,582	4,761,081	4,799,945	4,839,330	4,879,549	4,920,676
1840	Underground Conduit	270,770	420,634	466,260	515,016	566,233	620,641	679,395	742,542
1845	Underground Conductors and Devices	4,678,473	5,171,137	5,285,567	5,405,160	5,530,295	5,661,785	5,799,537	5,942,803
1850	Line Transformers	3,430,737	3,807,581	3,897,225	3,991,943	4,094,031	4,203,366	4,320,748	4,447,905
1851	Line Transformers - Pad Mounted Switchgear	-	715	1,494	2,780	4,593	6,751	9,061	11,449
1852	Line Transformers - UG Foundations and Vaults	-	2,657	4,435	6,725	9,612	13,056	16,969	21,300
1855	Services	152,729	300,083	346,713	398,538	455,961	518,690	587,296	662,602
1860	Meters	262,616	-	-	-	-	-	-	-
1861	Meters- Residential SM	-	457,654	591,003	726,858	866,779	957,589	989,812	1,015,284
1862	Meters- Industrial/ Commercial	-	120,401	155,570	191,162	227,220	263,777	299,377	325,333
1863	Meters- Wholesale	-	209	860	2,342	4,967	8,447	12,171	15,894
1864	Meters- CT's & PT's	-	11,375	14,786	18,277	21,797	25,336	28,902	32,502
1905	Land	-	-	-	-	-	-	-	-
1906	Land Rights	2,725	2,725	2,725	2,725	2,725	2,725	2,725	2,725
1908	Buildings and Fixtures	339,405	320,562	256,797	268,309	279,954	291,827	303,965	316,244
1915	Office Furniture and Equipment	208,126	234,369	241,918	250,032	257,947	265,401	272,315	279,145
1920	Computer Equipment - Hardware	353,166	382,040	394,195	407,089	419,793	432,235	443,323	453,607
1925	Computer Software	222,832	260,587	269,805	280,949	291,720	305,158	325,939	351,695
1930	Transportation Equipment	1,603,812	-	-	-	-	-	-	-
1931	Transportation Equipment- Heavy Vehicle	-	39,575	51,832	64,746	79,833	105,402	146,563	195,774
1932	Transportation Equipment- Light Vehicle	-	144,716	158,221	167,378	176,368	186,436	198,049	210,293
1933	Transportation Equipment- Underground	-	14,143	21,214	28,285	35,356	42,428	49,499	56,570
1940	Tools, Shop and Garage Equipment	313,085	358,183	366,763	374,237	380,192	385,314	390,757	397,398
1955	Communication Equipment	23,971	29,791	31,083	32,310	33,551	34,541	34,990	35,160
1985	Sentinel Lighting Rentals	-	15	15	15	15	15	15	15
1995	Contributions and Grants	-1,148,897	-2,042,903	-2,313,736	-2,595,534	-2,890,230	-3,205,980	-3,544,016	-3,901,387
Total Accumulated Amortization		**15,499,962**	**15,166,412**	**15,435,746**	**15,792,599**	**16,165,674**	**16,507,520**	**16,819,499**	**17,142,471**

3

2.3 VARIANCE ANALYSIS ON GROSS ASSETS

Table 2-16 below provides the same level of detail as Table 2-14 however, for the purposes of the variance analysis assets are categorized as Distribution Assets and General Plant and explanations on variances over E.L.K.'s materiality threshold are explained following the table.

Table 2-16 – Variance on Gross Assets

2012 Board Approved and 2016 Actual to 2022 Test Year

USoA	Description	2012 Board Approved	2016 Actuals	Variance 2012 Approved to 2016 Actuals	2017 Actuals	Variance 2016 Actuals to 2017 Actuals
1805	Land	2,112	2,112	-	2,112	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	142,098	142,098	-	142,098	-
1830	Poles, Towers and Fixtures	899,356	1,110,591	211,235	1,157,079	46,488
1835	Overhead Conductors and Devices	6,298,532	6,513,592	215,060	6,534,894	21,302
1840	Underground Conduit	1,341,878	2,320,756	978,878	2,506,240	185,483
1845	Underground Conductors and Devices	7,469,710	8,449,291	979,581	8,662,737	213,447
1850	Line Transformers	5,689,308	6,443,974	754,666	6,577,633	133,659
1851	Line Transformers - Pad Mounted Switchgear	-	11,213	11,213	19,914	8,701
1852	Line Transformers - UG Foundations and UG Vaults	-	83,356	83,356	109,904	26,548
1855	Services	741,071	1,072,170	331,099	1,184,386	112,217
1860	Meters	2,097,985	-	-2,097,985	-	-
1861	Meters- Residential SM	-	1,324,497	1,324,497	1,334,737	10,240
1862	Meters- Industrial/ Commercial	-	326,187	326,187	332,014	5,826
1863	Meters- Wholesale	-	5,245	5,245	14,289	9,044
1864	Meters- CT's & PT's	-	111,705	111,705	116,127	4,422
Distribution Plant Subtotal		**24,682,050**	**27,916,787**	**3,234,737**	**28,694,164**	**777,377**
1905	Land	171,765	127,082	-44,683	82,399	-44,683
1906	Land Rights	2,945	2,945	-	2,945	-
1908	Buildings and Fixtures	669,090	540,865	-128,224	416,288	-124,578
1915	Office Furniture and Equipment	244,159	273,389	29,230	294,281	20,891
1920	Computer Equipment - Hardware	363,468	415,793	52,325	428,525	12,732
1925	Computer Software	266,146	276,772	10,626	295,512	18,740
1930	Transportation Equipment	1,886,565	-	-1,886,565	-	-
1931	Transportation Equipment- Heavy Vehicle	-	116,061	116,061	125,909	9,848
1932	Transportation Equipment- Light Vehicle	-	184,334	184,334	197,489	13,155
1933	Transportation Equipment- Underground	-	70,712	70,712	70,712	-
1940	Tools, Shop and Garage Equipment	371,567	388,759	17,192	393,339	4,580
1955	Communication Equipment	35,831	36,872	1,042	36,872	-
1985	Sentinel Lighting Rentals	-	15	15	15	-
General Plant Subtotal		**4,011,536**	**2,433,601**	**-1,577,935**	**2,344,287**	**-89,314**
1995	Contributions and Grants	-4,195,546	-6,561,746	-2,366,200	-6,902,300	-340,554
Total		**24,498,040**	**23,788,642**	**-709,398**	**24,136,151**	**347,509**

USoA	Description	2018 Actuals	Variance 2017 Actuals to 2018 Actuals	2019 Actuals	Variance 2018 Actuals to 2019 Actuals	2020 Actuals
1805	Land	2,112	-	2,112	-	2,112
1820	Distribution Station Equipment - Normally Primary below 50 kV	142,098	-	142,098	-	142,098
1830	Poles, Towers and Fixtures	1,204,713	*47,635*	1,254,453	*49,739*	1,330,040
1835	Overhead Conductors and Devices	6,558,407	*23,513*	6,578,893	*20,486*	6,620,720
1840	Underground Conduit	2,633,745	*127,506*	2,752,317	*118,572*	2,952,933
1845	Underground Conductors and Devices	8,862,259	*199,522*	9,106,183	*243,924*	9,370,655
1850	Line Transformers	6,849,830	*272,197*	7,167,244	*317,414*	7,429,608
1851	Line Transformers - Pad Mounted Switchgear	31,548	*11,634*	40,958	*9,410*	45,378
1852	Line Transformers - UG Foundations and UG Vaults	144,855	*34,951*	181,427	*36,572*	211,728
1855	Services	1,331,954	*147,568*	1,464,322	*132,368*	1,597,211
1860	Meters	-	-	-	-	-
1861	Meters- Residential SM	1,374,637	*39,900*	1,416,048	*41,411*	1,455,157
1862	Meters- Industrial/ Commercial	339,212	*7,199*	346,329	*7,117*	355,406
1863	Meters- Wholesale	30,184	*15,895*	48,559	*18,375*	55,851
1864	Meters- CT's & PT's	118,077	*1,950*	118,502	*425*	119,576
Distribution Plant Subtotal		**29,623,633**	***929,469***	**30,619,446**	***995,813***	**31,688,472**
1905	Land	82,399	-	82,399	-	82,399
1906	Land Rights	2,945	-	2,945	-	2,945
1908	Buildings and Fixtures	421,348	*5,061*	429,647	*8,299*	444,025
1915	Office Furniture and Equipment	296,177	*1,896*	297,762	*1,584*	303,583
1920	Computer Equipment - Hardware	430,400	*1,875*	436,745	*6,345*	452,499
1925	Computer Software	298,672	*3,160*	301,812	*3,140*	341,115
1930	Transportation Equipment	-	-	-	-	-
1931	Transport. Equip.- Heavy Vehicle	135,756	*9,848*	191,131	*55,375*	450,196
1932	Transport. Equip.- Light Vehicle	197,489	-	217,448	*19,959*	237,406
1933	Transport. Equip. - Underground	70,712	-	70,712	-	70,712
1940	Tools, Shop and Garage Equip.	402,444	*9,105*	411,456	*9,012*	413,623
1955	Communication Equipment	36,872	-	37,149	*276*	37,481
1985	Sentinel Lighting Rentals	15	-	15	-	15
General Plant Subtotal		**2,375,231**	***30,945***	**2,479,221**	***103,990***	**2,836,000**
1995	Contributions and Grants	-7,110,031	*(207,731)*	-7,547,161	*-437,130*	-8,162,711
Total		**24,888,833**	***752,682***	**25,551,506**	***662,673***	**26,361,760**

1

USoA	Description	Variance 2019 Actuals to 2020 Actuals	2021 Bridge Year	Variance 2020 Actuals to 2021 Bridge	2022 Test Year	Variance 2021 Bridge to 2022 Test Year
1805	Land	-	2,112	-	2,112	-
1820	Distribution Station Equipment - Normally Primary below 50 kV	-	142,098	-	142,098	-
1830	Poles, Towers and Fixtures	*75,587*	1,530,961	*200,921*	1,787,961	*257,000*
1835	Overhead Conductors and Devices	*41,827*	6,679,134	*58,414*	6,729,634	*50,500*
1840	Underground Conduit	*200,616*	3,186,828	*233,895*	3,392,328	*205,500*
1845	Underground Conductors and Devices	*264,471*	9,607,193	*236,539*	9,811,693	*204,500*
1850	Line Transformers	*262,364*	7,811,041	*381,433*	8,211,541	*400,500*
1851	Line Transformers - Pad Mounted Switchgear	*4,420*	47,018	*1,640*	48,518	*1,500*
1852	Line Transformers - UG Foundations and UG Vaults	*30,301*	237,771	*26,043*	261,771	*24,000*
1855	Services	*132,889*	1,758,191	*160,979*	1,932,191	*174,000*
1860	Meters	-	-	-	-	-
1861	Meters- Residential SM	*39,109*	1,500,506	*45,349*	1,528,506	*28,000*
1862	Meters- Industrial/ Commercial	*9,077*	372,350	*16,944*	387,350	*15,000*
1863	Meters- Wholesale	*7,292*	55,851	-	55,851	-
1864	Meters- CT's & PT's	*1,073*	120,724	*1,148*	122,224	*1,500*
Distribution Plant Subtotal		***1,069,025***	**33,051,778**	***1,363,306***	**34,413,778**	***1,362,000***
1905	Land	-	82,399	-	82,399	-
1906	Land Rights	-	2,945	-	2,945	-
1908	Buildings and Fixtures	*14,378*	456,164	*12,139*	458,164	*2,000*
1915	Office Furniture and Equipment	*5,822*	310,223	*6,640*	312,223	*2,000*
1920	Computer Equipment - Hardware	*15,754*	465,580	*13,081*	481,580	*16,000*
1925	Computer Software	*39,303*	401,719	*60,604*	428,219	*26,500*
1930	Transportation Equipment	-	-	-	-	-
1931	Transport. Equip.- Heavy Vehicle	*259,065*	658,886	*208,690*	848,886	*190,000*
1932	Transport. Equip.- Light Vehicle	*19,959*	254,906	*17,500*	272,406	*17,500*
1933	Transport. Equip. - Underground	-	70,712	-	70,712	-
1940	Tools, Shop and Garage Equip.	*2,167*	424,127	*10,504*	439,127	*15,000*
1955	Communication Equipment	*332*	37,537	*56*	37,537	-
1985	Sentinel Lighting Rentals	-	15	-	15	-
General Plant Subtotal		***356,779***	**3,165,214**	***329,214***	**3,434,214**	***269,000***
1995	Contributions and Grants	*-615,550*	-8,661,484	*-498,772*	-9,129,435	*(467,951)*
Total		***810,254***	**27,555,508**	***1,193,747***	**28,718,556**	***1,163,049***

2017 Actual compared to 2016 Actual

Distribution Assets Variance: $777,377

2017 Actual Distribution Assets were higher than the 2016 amounts by $777,377. The items primarily related to this variance include:

- Increased capital investment in underground conduit, underground conductors and devices and Line transformers throughout our service areas with emphasis on converting overhead services to underground. An increase in service connections was the result of new residential subdivisions commencing in two service areas.

General Assets Variance: -$89,314

2017 Actual General Assets were lower than the 2016 amount by $89,314. This item is primarily related to the sale of the 24 Pearl Street Kingsville building.

2018 Actual compared to 2017 Actual

Distribution Assets Variance: $929,469

2018 Actual Distribution Assets were higher than the 2017 actual amounts by $929,469. The items primarily related to this variance include increased capital investment in underground conduit, underground conductors and devices and Line transformers throughout our service areas. Service connections continued to increase with more growth in the service areas.

General Assets Variance: $30,945

2018 Actual General Assets were higher than the 2017 actual by $30,945. This item is primarily related to general price increases in maintaining general plant.

2019 Actual compared to 2018 Actual

Distribution Assets Variance: $995,813

2019 Actual Distribution Assets were higher than the 2018 actual amounts by $995,813. The items primarily related to this variance include: Increased capital investment in underground conduit, underground conductors and devices and Line transformers throughout our service areas with emphasis on converting overhead services to underground. An increase in service connections was the result of new residential subdivisions commencing in three service areas.

General Assets Variance: $103,990

2019 Actual General Assets were higher than the 2018 actual by $103,990. This item is primarily related to a RBD Digger Truck chassis purchase.

2020 Actual compared to 2019 Actual

Distribution Assets Variance: $1,069,025

2020 Actual Distribution Assets were higher than the 2019 actual amounts by $1,069,025. The items primarily related to this variance include increased capital investment in underground conduit, underground conductors and devices and Line transformers throughout our service areas with emphasis on converting overhead services to underground. An increase in service connections was the result of two new residential subdivisions, condo complex and commercial services commencing in three service areas.

General Assets Variance: $356,779

2020 Actual General Assets were higher than the 2019 actual by $356,779. This item is primarily related to the purchase of a RBD Digger Truck

2021 Bridge Year compared to 2020 Actual

Distribution Assets Variance: $1,363,306

2021 Bridge Year Distribution Assets are higher than the 2020 actual amounts by $1,363,306. The items primarily related to this variance include: Increased capital investment in underground conduit, underground conductors and devices and Line transformers throughout service areas with emphasis on converting overhead services to underground. An increase in service connections was the result of increased growth in all service areas

General Assets Variance: $329,214

2021 Bridge General Assets are higher than the 2020 actual by $329,214. This item is primarily related to the replacement of a pickup truck, replacement of a Dump Truck chassis and new Double bucket truck.

2022 Test compared to 2021 Bridge

Distribution Assets Variance: $1,362,000

2022 Test Distribution Assets are higher than the 2021 Bridge amounts by $1,362,000. The items primarily related to this variance include:

Increased capital investment in poles, pole treatments, underground conduit, underground conductors and devices and Line transformers throughout our service areas as a result of our asset condition assessment. A continued increase in service connections will be the result of increased growth in all of service areas.

General Assets Variance: $269,000

2022 Test General Assets are higher than the 2021 Bridge by $269,000. This item is primarily related to the replacement of a single bucket truck.

2.4 SUMMARY OF INCREMENTAL CAPITAL MODULE ADJUSTMENT

E.L.K. confirms that it has not applied for nor received any ICM adjustments as part of a previous IRM application.

2.5 RECONCILIATION OF CONTINUITY STATEMENTS TO CALCULATED DEPRECIATION EXPENSES

E.L.K. confirms that the depreciation expenses in the fixed asset continuity statements reconcile to the calculated depreciation expenses under Exhibit 4 – Operating Costs and are presented by account. As such there are no reconciling items between the fixed asset continuity statements in this Exhibit and the calculated depreciation expense in Exhibit 4.

3.0 ALLOWANCE FOR WORKING CAPITAL

3.1 OVERVIEW

The Filing Requirements permit applicants to take one of two approaches for the calculation of the allowance for working capital; the 7.5% Allowance Approach or the filing of a lead/lag study. Using the 7.5% Allowance Approach, the working capital allowance is calculated to be 7.5% of the sum of Cost of Power ("**COP**") and controllable expenses (Operations, Maintenance, Billing and Collecting, Community Relations, Administration and General). E.L.K. did not conduct a lead lag study and is using the 7.5% Allowance Approach in accordance with the Filing Requirements.

The working capital allowance for the 2016 actuals to 2022 Test Year is based upon 7.5% of the COP and controllable expenses.

Table 2-17 provides a summary of E.L.K.'s COP and controllable expenses used to calculate working capital allowance for 2012 Board Approved, 2016 Actual, 2017 Actual, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Bridge Year and the 2022 Test Year.

Table 2-17- Summary of Working Capital Allowance

Expenses for Working Capital	2012 Approved	2016 Actual	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Bridge Year	2022 Test Year
Eligible Distribution Expenses								
Operation	291,000	284,289	284,584	273,238	311,700	284,999	387,414	521,943
Maintenance	455,000	647,045	626,094	696,284	774,109	578,700	804,383	924,630
Billing & Collecting	775,064	605,236	635,071	719,649	669,849	551,626	678,651	721,707
Community Relations	10,000	7,585	3,497	20,967	6,065	3,438	10,000	11,537
Administrative & General Expenses	917,908	996,936	1,094,108	937,336	1,104,987	1,018,894	1,329,657	1,346,008
Donations - LEAP	38	5,179	5,179	5,179	5,179	10,179	5,179	5,617
Taxes other than Income Taxes	23,000	15,346	16,905	17,768	18,791	19,180	20,000	20,000
Total Eligible Distribution Expenses	2,472,009	2,561,616	2,665,438	2,670,420	2,890,679	2,467,017	3,235,284	3,551,441
Power Supply Expenses	25,248,949	30,683,184	30,973,150	29,265,330	31,178,390	35,246,686	26,507,696	26,380,096
Total Expenses for Working Capital	27,720,959	33,244,800	33,638,588	31,935,750	34,069,069	37,713,703	29,742,980	29,931,537
Working Capital Factor	12.0%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Total Working Capital Allowance	3,326,515	2,493,360	2,522,894	2,395,181	2,555,180	2,828,528	2,230,724	2,244,865

3.2 COST OF POWER CALCULATIONS

E.L.K. has calculated cost of power for the 2022 Test Year based on the results of the load forecast which is discussed in detail in Exhibit 3. The electricity prices used in the calculation were the published prices in the OEB's Regulated Price Plan Report – November 1, 2021 to October 31, 2022, issued October 22, 2021.

The cost of power calculations for the 2022 Test Year and a cost of power summary are provided in the following Table 2-18 and Table 2-19.

Table 2-18: 2022 Test Year Cost of Power Forecast Calculation

		2022 Test Year	RPP		2022 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast				-				
Residential	kWh	95,630,301		9,649,097	1,951,639		60,715	
GS<50 kW	kWh	25,109,816		2,533,580	3,752,041		116,726	
GS>50 kW	kWh	1,761,113		177,696	60,313,481		1,876,352	
Streetlights	kWh	-		-	1,366,018		42,497	
Unmetered Scattered Load	kWh	-		-	259,034		8,059	
Sentinel Lights	kWh	-		-	148,186		4,610	
Embedded Distributor	kWh	-		-	60,251,422		1,874,422	
-		-		-	-		-	
-		-		-	-		-	
SUB-TOTAL		122,501,230		12,360,374	128,041,821		3,983,381	$ 16,343,755

Global Adjustment non-RPP	Units	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh			0			134,234	
GS<50 kW	kWh			0			258,065	
GS>50 kW	kW			0			2,907,105	
Streetlights	kW			0			93,955	
Unmetered Scattered Load	kWh			0			17,816	
Sentinel Lights	kW			0			10,192	
Embedded Distributor	kW			0			4,144,093	
				0				
				0				
SUB-TOTAL		0		0			7,565,460	$ 7,565,460

Transmission - Network	Units	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	95,630,301	0.0081	770,093	1,951,639	0.0081	15,716	
GS<50 kW	kWh	25,109,816	0.0071	177,612	3,752,041	0.0071	26,540	
GS>50 kW	kW	7,960	2.9719	23,657	191,040	2.9719	567,758	
Streetlights	kW	-	2.2416	-	3,787	2.2416	8,489	
Unmetered Scattered Load	kWh	-	0.0071	-	259,034	0.0071	1,832	
Sentinel Lights	kW	-	2.2525	-	373	2.2525	841	
Embedded Distributor	kW	-	2.9719	-	138,872	2.9719	412,716	
				-			-	
				-			-	
				-			-	
SUB-TOTAL				971,362			1,033,892	2,005,254

Transmission - Connection	Units	Volume	Rate	$	Volume	Rate	$	Total
Class per Load Forecast								
Residential	kWh	95,630,301	0.0061	587,924	1,951,639	0.0061	11,998	
GS<50 kW	kWh	25,109,816	0.0054	135,414	3,752,041	0.0054	20,234	
GS>50 kW	kW	7,960	2.1946	17,469	191,040	2.1946	419,253	
Streetlights	kW	-	1.6976	-	3,787	1.6976	6,429	
Unmetered Scattered Load	kWh	-	0.0054	-	259,034	0.0054	1,397	
Sentinel Lights	kW	-	1.7334	-	373	1.7334	647	
Embedded Distributor	kW	-	2.1946	-	138,872	2.1946	304,765	
				-			-	
				-			-	
SUB-TOTAL				740,807			764,724	1,505,531

Wholesale Market Service	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	95,630,301	0.0030	286,891	1,951,639	0.0030	5,855	
GS<50 kW	kWh	25,109,816	0.0030	75,329	3,752,041	0.0030	11,256	
GS>50 kW	kWh	1,761,113	0.0030	5,283	42,266,715	0.0030	126,800	
Streetlights	kWh	-	0.0030	-	1,366,018	0.0030	4,098	
Unmetered Scattered Load	kWh	-	0.0030	-	259,034	0.0030	777	
Sentinel Lights	kWh	-	0.0030	-	148,186	0.0030	445	
Embedded Distributor	kWh	-	0.0030	-	60,251,422	0.0030	180,754	
				-			-	
				-			-	
SUB-TOTAL				367,504			329,985	697,489

Class A CBR	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate [4]	$	Total
Residential	kWh			-			-	
GS<50 kW	kWh			-			-	
GS>50 kW	kW			-	18,046,767	0.0004	7,219	
Streetlights	kW			-			-	
Unmetered Scattered Load	kWh			-			-	
Sentinel Lights	kW			-			-	
Embedded Distributor	kW			-			-	
				-			-	
				-			-	
SUB-TOTAL				-			7,219	7,219

Class B CBR	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	95,630,301	0.0004	38,252	1,951,639	0.0004	781	
GS<50 kW	kWh	25,109,816	0.0004	10,044	3,752,041	0.0004	1,501	
GS>50 kW	kWh	1,761,113	0.0004	704	42,266,715	0.0004	16,907	
Streetlights	kWh	-	0.0004	-	1,366,018	0.0004	546	
Unmetered Scattered Load	kWh	-	0.0004	-	259,034	0.0004	104	
Sentinel Lights	kWh	-	0.0004	-	148,186	0.0004	59	
Embedded Distributor	kWh	-	0.0004	-	60,251,422	0.0004	24,101	
				-			-	
				-			-	
SUB-TOTAL				49,000			43,998	92,999

RRRP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	95,630,301	0.0005	47,815	1,951,639	0.0005	976	
GS<50 kW	kWh	25,109,816	0.0005	12,555	3,752,041	0.0005	1,876	
GS>50 kW	kW	1,761,113	0.0005	881	42,266,715	0.0005	21,133	
Streetlights	kW	-	0.0005	-	1,366,018	0.0005	683	
Unmetered Scattered Load	kWh	-	0.0005	-	259,034	0.0005	130	
Sentinel Lights	kW	-	0.0005	-	148,186	0.0005	74	
Embedded Distributor	kW	-	0.0005	-	60,251,422	0.0005	30,126	
				-			-	
				-			-	
SUB-TOTAL				61,251			54,998	116,248

Low Voltage - No TLF adjustment **Class per Load Forecast**	**Units**	Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	91,637,035	0.0033	300,610	1,870,144	0.0033	6,135	
GS<50 kW	kWh	24,061,297	0.0029	69,332	3,595,366	0.0029	10,360	
GS>50 kW	kW	7,960	1.2107	9,637	191,040	1.2107	231,285	
Streetlights	kW	-	0.9132	-	3,787	0.9132	3,458	
Unmetered Scattered Load	kWh	-	0.0029	-	248,217	0.0029	715	
Sentinel Lights	kW	-	0.9176	-	373	0.9176	343	
Embedded Distributor	kW	-	1.2107	-	138,872	1.2107	168,126	
				-			-	
				-			-	
SUB-TOTAL				379,578			420,422	800,000

Smart Meter Entity Charge **Class per Load Forecast**		Customers	Rate	$	Customers	Rate	$	Total
Residential	kWh	10,981	0.57	75,109			-	
GS<50 kW	kWh	1,257	0.57	8,600			-	
				-			-	
SUB-TOTAL				83,709			-	83,709
SUB- TOTAL				15,013,586			14,204,078	29,217,664
OER CREDIT[3]	18.90%			(2,837,568)			0	(2,837,568)
TOTAL				**12,176,018**			**14,204,078**	**26,380,096**

Table 2-19: 2022 Test Year Cost of Power Summary

2022 Test Year - COP	
4705 -Power Purchased	$16,343,755
4707- Global Adjustment	$7,565,460
4708-Charges-WMS	$913,954
4714-Charges-NW	$2,005,254
4716-Charges-CN	$1,505,531
4750-Charges-LV	$800,000
4751-IESO SME	$83,709
OER Credit	$(2,837,568)
TOTAL	**$26,380,096**

4.0 CAPITAL EXPENDITURES

4.1 PLANNING

The Board's RRFE is designed to support the cost-effective planning and operation of the distribution network and that of LDC distribution systems. The RRFE takes an integrated approach to planning in order to facilitate priorities and pacing of capital expenditures. In accordance with the filing requirements, E.L.K. is filing its consolidated DSP as a stand-alone document which includes all elements of the DSP as Exhibit 2, Tab 4, Attachment 1.

E.L.K. has organized the information contained in the DSP using the headings indicated in Chapter Five of the Board's Filing Requirements for Electricity Distribution and Transmission Applications, Consolidated Distribution System Plan Filing Requirements dated June 14, 2021. The DSP incorporates matters pertaining to asset management, regional planning, and renewable energy generation.

The intention underlying DS Planning at E.L.K. encourages a process of "continuous improvement." The following steps that have been adapted through the planning process:

- Establish the objectives and processes necessary to deliver results in accordance with the expected outcomes. Start, on a small scale, to test possible effects and financial feasibility. Develop a DS Plan, prioritizing budgets, resources, and timelines.
- Implement the Plan and collect data for analysis. Develop projects' design and execution, preparing status reports, and implementing planned activities.
- Study the actual results and compare against the expected results to ascertain any differences. Evaluate any deviations in implementation from the Plan, and evaluate the appropriateness and completeness of the Plan to enable the execution. This Plan elaborates on E.L.K.'s Performance Outcomes.
- Recommend improvements and adjustments to the initial plan; determine the course of corrections and modifications to the plan.

In this DSP, E.L.K. also describes the areas where it has been determined that the asset management process, systems and data need to be improved. E.L.K.'s DS network provides an essential service to the community and needs to be reliable and sustainable. The electricity distribution infrastructure assets are capital-intensive and have a long life. E.L.K. will continue to monitor and optimize the network performance, further refine effective investment strategies and refocus activities, as needed, to meet established targets.

To facilitate better planning, prioritization and pacing of capital expenditures, E.L.K. is using an integrated approach to planning. This means E.L.K.'s capital expenditure plan consolidates all categories of system investments, including investments to renew and expand the distribution system. The DSP will be amended, as required, with information about investments that will be identified during the regional planning process, and will include investments to accommodate the connection of renewable generation or to implement a smart grid.

This is the first effort of E.L.K. to use an integrated framework approach. E.L.K. first developed a long term Distribution Asset Management Plan (DAMP) in 2012. The current plan, however, consolidates information that includes data about renewable generation (REG), smart grid and other components compliant with the requirements of Chapter 5.

4.1.1 PLANNING HORIZON

This DSP encompasses projections and forecasts for the 2022 - 2026 timeframe. It is intended that the DSP will be reviewed on a periodic basis, and amended with new information as it becomes available.

The planning horizon extends to a five (5) year period based on Chapter 5 requirements for Consolidated Distribution System Planning. Under the renewed regulatory framework, a planning horizon of five (5) years is required to support integrated planning and better alignment of E.L.K.'s planning cycles with rate-setting cycles. A longer-term approach enhances the predictability necessary to facilitate planning and decision-making by customers and distributors. This also facilitates the cost-effective and efficient implementation of the DSP and meeting of OEB expectations in the areas of performance outcomes. The asset assessments are also based on a five (5) year planning period. It is very likely that new developments, not currently identified here, will arise at any given time, and will be amended into the plan.

In order to support integrated planning and better align the distributor planning cycles with rate-setting cycles, the approach to longer-term planning (a minimum of five years) has incorporated the following elements into the plan.

Longer-Term Planning Element	Approach
Enhance the predictability necessary to facilitate planning – including regional planning – and decision-making by customers and distributors	Heighten the emphasis on regionally-planned infrastructure Complete system renewal and expansion – refresh assets in totality, as per assets' lifecycle using a longer-term bottom-up approach Assess the available capacity for renewable energy generation efforts and community growth
Facilitate the cost-effective and efficient implementation of distributor DS Plans and, thereby, the achievement of customer service and cost performance outcomes	Initiate study and assessment for enhancement of customer communication and implementation of Outage Management System Improve customer communication
Manage consumer rate impacts	Develop detailed implementation plans Enhance REG to help manage rate impacts Assess capital investment scenarios in terms of risk mitigation and longer-term smoothing of customer rate impacts

4.1.2 CAPITAL EXPENDITURE PLANNING PROCESS

The asset management process is the foundation to the capital expenditure plan and DSP, which helps align each to overall corporate objectives. By following a strategic approach to the capital expenditure planning process E.L.K. achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers and providing the highest level of shareholder and customer value.

In the development of the capital expenditure plan, a number of objectives and planning processes are observed and adhered to in order to align the plan with the goals and overall strategic direction of the company. E.L.K.'s planning objectives that have informed the DSP and capital expenditure plan include:

- Ensure allocation of investments to meet regulatory obligations of the System Access such as metering, system relocations for municipal road work, and future system requirements for residential, commercial and industrial customers.
- Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system.
- Ensure proper allocation of investments in General Plant assets to support investment initiatives.
- Undertake a fault indicator program to ensure it can monitor and manage unplanned outages more effectively; and
- Review overall expenditures and determine impacts to financials and adjust spending as required to ensure impact on customer rates are minimized where possible.

The level of investments required for System Access projects is determined through consultations with the municipal government and based on the number of anticipated development and building permits for residential and commercial construction. The System Renewal investments are determined through asset condition assessments and the identification of economically efficient investments. The level of investments required for General Plant are determined through the assessment of its E.L.K.'s fleet, facilities and IT systems, reviewing the age, obsoleteness and industry best practices for these areas.

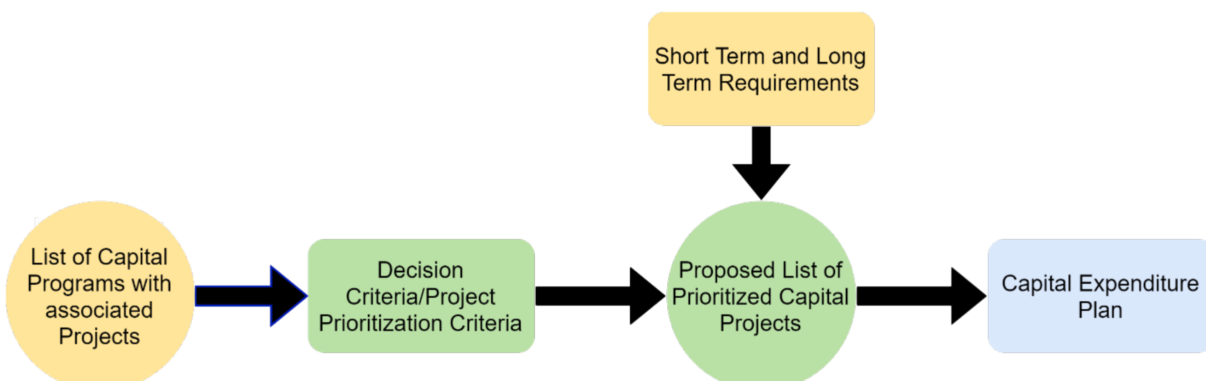
E.L.K. will undertake the deployment of fault circuit indicators onto the distribution lines in its service territories. These fault indicators will allow for more accurate visibility on faults within the distribution system to identify targeted areas for power service restoration and monitoring.

E.L.K. engages with customers to ensure that planning processes for capital and maintenance work is in line with customer expectations and to understand the risks that need to be addressed. These engagements include meetings with municipal teams, information sessions, open houses, customer class specific meetings and the bi-annual customer satisfaction survey. E.L.K. also conducts informal engagements such as front-line staff and management listening to customers at the front desk and operations staff working with customers and contractors on day-to-day projects. The continued message from customers is for E.L.K. to continue providing safe and reliable service, improve reliability in service areas where reliability has been affected in the past, and to mitigate rate increases where possible. Some customers, however, have accepted that rates may go up as long as the reliability in their service areas is improved to the level they expect. E.L.K. undertook a DSP customer survey in 2021 to identify customer priorities for the 2022-2026 period. Below are the top customer priorities identified that E.L.K. has used in the development and prioritization of its investment plan for the 2022-2026 period.

1) Ensure reliable electric service
2) Deliver electricity at reasonable prices
3) Prioritize investments that will help improve system reliability, power quality, utility efficiency and operations.
4) Reduce the overall number of outages

E.L.K.'s capital expenditure process is detailed in Figure 2-1 below:

Figure 2-1:Capital Expenditure Process



E.L.K. projects can either be categorized as non-discretionary or discretionary. Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet customer or developer requirements. Projects that reside in System Renewal, System Service, and General Plant are typically categorised as discretionary. These projects are prioritized based on risk associated with not undertaking each project, and the resource and budget available to deliver those projects. Where appropriate, E.L.K. looks to group projects into programs, mainly within its System Renewal category. For example, each year E.L.K. needs to replace a number of poles that have reached end of life and/or in poor and very poor condition. These investments fall within E.L.K.'s Pole Replacement Program.

4.1.3 REGIONAL PLANNING

Regional planning is conducted through the Integrated Regional Resource Planning (IRRP) process, where local stakeholders collaborate in the development of integrated solutions for maintaining a reliable supply of electricity to Ontario communities.

The objective of the IRRP process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options, such as conservation and demand management, distributed generation, large-scale generation, transmission and distribution.

As per Hydro One's regional planning initiative the province is divided into three planning groups:

Group 1, Group 2 & Group 3 – Active Plans

A Regional Infrastructure Plan and an Integrated Regional Resource Plan have been completed for E.L.K.'s service territory.

Chapter 5 implements the Board's policy direction on 'an integrated approach to distribution network planning'. Regional planning is conducted through the Integrated Regional Resource Planning (IRRP) process, whereby local stakeholders collaborate in the development of integrated solutions for maintaining a reliable supply of electricity to Ontario communities. The regional planning process begins with a needs assessment performed by the transmitter, which determines whether a regional plan is required or not. If a regional plan is required, the IESO then conducts a scoping assessment to determine whether a more comprehensive Integrated Regional Resource Plan is required (led by the IESO), or a more transmission - and distribution - focused Regional Infrastructure Plan is required (led by the transmitter).

The objective of the IRRP process is to develop long-term electricity plans that thoughtfully integrate all relevant resource options, such as conservation and demand management, distributed generation, large-scale generation, transmission and distribution.

E.L.K. is part of the Windsor-Essex Region planning zone in Southern Ontario. The LDCs providing service to customers in the **Windsor-Essex** region include:

- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- ENWIN Utilities Ltd.
- Essex Powerlines Corporation.
- Hydro One Networks Inc.

A Regional Infrastructure Plan and an Integrated Regional Resource Plan have been completed for E.L.K.'s service territory. E.L.K. is included in "Group 1", which is the first group in the regional planning prioritization.

Information from the municipal development department is also used to project the amount of customer-driven activity (such as community upgrades or new commercial construction). These projects fit into the Annual Capital Budget directly, and are used to allocate the customer driven portion of the 5-year capital budget.

Infrastructure planning on a regional basis is required to ensure that regional issues and requirements are effectively integrated into E.L.K.'s planning processes, which will, in turn, help promote the cost-effective development of electricity infrastructure in the Province. The effective use of regional infrastructure planning and the inclusion of regional considerations in E.L.K.'s DS Plan is the key to ensure coordinated development and implementation of smart grid provincial strategy. It is important that the necessary investments are made in distribution and transmission systems that will best serve the interests and the future of the region.

E.L.K.'s intention is to follow the Board's directions and work to address regional planning issues as they arise. E.L.K. will assess and amend actions where appropriate. E.L.K. makes decisions based upon the most cost-effective solutions, and is considering conservation as one of the options to defer the need for infrastructure investments.

4.2 REQUIRED INFORMATION

E.L.K. has provided a copy of the Distribution System Plan (DSP) as Exhibit 2, Tab 4, Attachment 1.

E.L.K. has completed Appendix 2-AB Capital Expenditure Summary presenting four historical years, the 2021 Bridge Year and five planned years of capital expenditures. This is the first year for which E.L.K. has filed a DSP, and as such E.L.K. has entered the planned total capital budget in the "Plan" column for each historical year and for the bridge year including the OEB approved amount for the last rebasing year. The variance in the 2012 actual compared to the 2012 OEB approved amount is primarily the result of a development called Jakana which did not occur until 2013 that was planned for 2012 in the amount of $161,193. Further, there was approximately $15,000 less spent on the Viscount Estates work in 2012 and some of the building improvement and tools were deferred into the following years. E.L.K. has made its best efforts to categorize historical projects into the DSP categories (System Access, System Renewal, System Service, and General Plant).

Appendix 2-AB Capital Expenditure Summary is presented in Table 2-20 below.

<u>Table 2-20</u>

Appendix 2-AB

CATEGORY	Historical Period (previous plan[1] & actual)											
	2012			2017			2018			2019		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access		567	--	560	614	9.6%	677	558	-17.6%	694	875	26.1%
System Renewal		207	--	262	174	-33.7%	295	513	73.9%	459	45	-90.1%
System Service		-	--		-	--		-	--		-	--
General Plant		11	--	492	28	-94.3%	457	34	-92.6%	457	174	-61.9%
TOTAL EXPENDITURE	-	785	--	1,314	816	-37.9%	1,429	1,105	-22.7%	1,610	1,095	-32.0%
Capital Contributions	-	- 446	--	- 614	- 243	-60.5%	- 557	- 173	-69.0%	- 875	- 702	-19.8%
Net Capital Expenditures		- 445	--	700	573	-18.1%	872	932	6.9%	735	393	-46.5%
System O&M	$ -	$ 877	--	$ 1,542	$ 911	-41.0%	$1,413	$ 970	-31.4%	$1,478	$1,086	-26.5%

Appendix 2-AB

CATEGORY	Historical Period (previous plan[1] & actual)						Forecast Period (planned)				
	2020			2021			2022	2023	2024	2025	2026
	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000				
System Access	711	726	2.0%	1,089	659	-39.4%	867	943	1,108	1,144	1,183
System Renewal	476	492	3.3%	420	152	-63.7%	307	370	452	494	539
System Service		-	--		-	--	42	42	42	42	83
General Plant	177	539	204.8%	119	475	298.8%	419	609	244	227	56
TOTAL EXPENDITURE	1,365	1,757	28.8%	1,628	1,286	-21.0%	1,634	1,963	1,845	1,907	1,862
Capital Contributions	- 1,081	- 530	-51.0%	- 468	- 468	0.0%	468	477	487	497	507
Net Capital Expenditures	284	1,227	332.9%	1,160	819	-29.4%	1,166	1,486	1,358	1,410	1,355
System O&M	$1,455	$ 864	-40.7%	$ 952	$ 925	-2.8%	$1,447	$1,476	$ 1,505	$1,535	$ 1,566

Capital spending by category is designed to meet both defined customer preferences and distribution system requirements.

During the five-year period, E.L.K. is strategically planning to make leveled investments in distribution infrastructure required for system sustainment, and in the short–term, intends to concentrate on investing in general assets that support service reliability and customer preferences. Therefore, the main investment drivers are in the areas of end of useful life of the assets, business operational efficiently, reliability and customer preferences. Capital spending by category is designed to meet both defined customer preferences and distribution system requirements.

- System Access investments are planned on historical actual levels required to meet regulatory obligations for connections, upgrades and plant relocation driven by customers and third parties. E.L.K. expects that its system will continue to be able to accommodate the vast majority of requests for new load connections and for service upgrades.
- System Renewal investments are based on the requirements of asset replacement programs, mainly driven by pole replacement. Plans for replacements are based on consideration of age and condition of assets. The proactive replacement of system components prior to failure will reduce costs associated with outage response and reactive replacement. Adjustments to the programs will be completed with gathering more detailed asset condition information and records. The annual investments are leveled to ensure consistency throughout the planning process.

- System Service spending is focused on system reliability improvement projects, which are based on outage considerations, system impact, smart grid upgrade scenarios and customer preferences. E.L.K. has not experienced any major issues with connection of existing microFIT or small FIT projects to its system, and does not expect any issues within the current five-year plan, based on the anticipated volume of new projects.
- General Plant category is focused on ensuring that adequate tools, such as OMS, are in place to support the day-to-day operations, and to improve customer communications in contingency scenarios of unplanned outages.

E.L.K. has incorporated the customer preferences obtained through targeted customer research and customer engagement process.

4.3 DRIVERS BY INVESTMENT CATEGORY

System Access

Expenditures within the System Access category are driven by external requirements such as servicing new customer loads and relocating distribution assets to suit road or municipal authorities. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. Most of the forecasted investments in this category are based on historical averages, while being supported by information from external agencies and municipalities in the E.L.K. service territory.

There are two main categories that E.L.K. anticipates System Access investments to fall into: Subdivision development and rebuilds. Subdivision developments including new electrical supply and materials to residential and commercial developments where no current supply exists. System Access rebuilds include the relocation or enhancement of assets because of infrastructure development driven outside of an E.L.K. need, such as road rebuilds.

System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. E.L.K. conducted both an asset condition assessment and pole health assessment to inform decisions for System Renewal within the DSP. The output of these assessments and processes led to targeted programs for capital expenditure and prioritization of System Renewal.

There are two major focus areas for E.L.K.'s System Renewal activities: transformer replacements and upgrade, and pole replacement and treatment. As part of these asset renewal projects, E.L.K. intends to replace on average 18 poles per year that are in "very poor" or "poor" health condition as well as undertake treatment activities on other at-risk poles in the service territory. Additionally, for the transformer replacement project, E.L.K. intends to identify and replace degraded or end of useful life transformers within the system. These investments are aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers.

E.L.K. has experienced worsening SAIDI and SAIFI trends over the historical period, with the worst performance year occurring in 2020. This is mainly due to storm events and adverse weather:

- In 2020, the targets for both SAIDI and SAIFI were exceeded. This was due to three major events; a large adverse weather event and two lightning storms in June and August of 2020.
- In 2019, the targets for both SAIDI and SAIFI were exceeded. This was due to two major events; a large adverse weather event and animal contact in July and August of 2019.
- In 2018, targets were exceeded as a result of an electricity outage in April due to a storm event.

It is important to note that in any given year, outage hours and frequency will correlate with storm occurrences and severity. E.L.K.'s reliability metric values for the historical period, adjusting for loss of supply and major event days, are shown in the tables below.

Table 2-21: Historical Reliability Performance Metrics

Metric	2016	2017	2018	2019	2020	Average
SAIDI	0.42	0.63	2.95	2.66	5.45	2.42
SAIFI	0.17	0.21	1.13	1.31	2.17	1.00
CAIDI	2.47	3.00	2.61	2.03	2.51	2.52

Table 2-22: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2016	2017	2018	2019	2020	Average	E.L.K. Target
Loss of Supply Adjusted							
SAIDI	0.25	0.63	1.63	1.85	3.32	1.54	--
SAIFI	0.09	0.21	0.48	0.72	1.14	0.53	--
CAIDI	2.78	3.00	3.40	2.57	2.91	3.04	--
Loss of Supply and Major Event Days Adjusted							
SAIDI	0.25	0.63	1.63	1.85	3.34	*1.54*	*0.99*
SAIFI	0.09	0.21	0.48	0.72	1.15	*0.53*	*0.34*
CAIDI	2.78	3.00	3.40	2.57	2.90	*2.93*	--

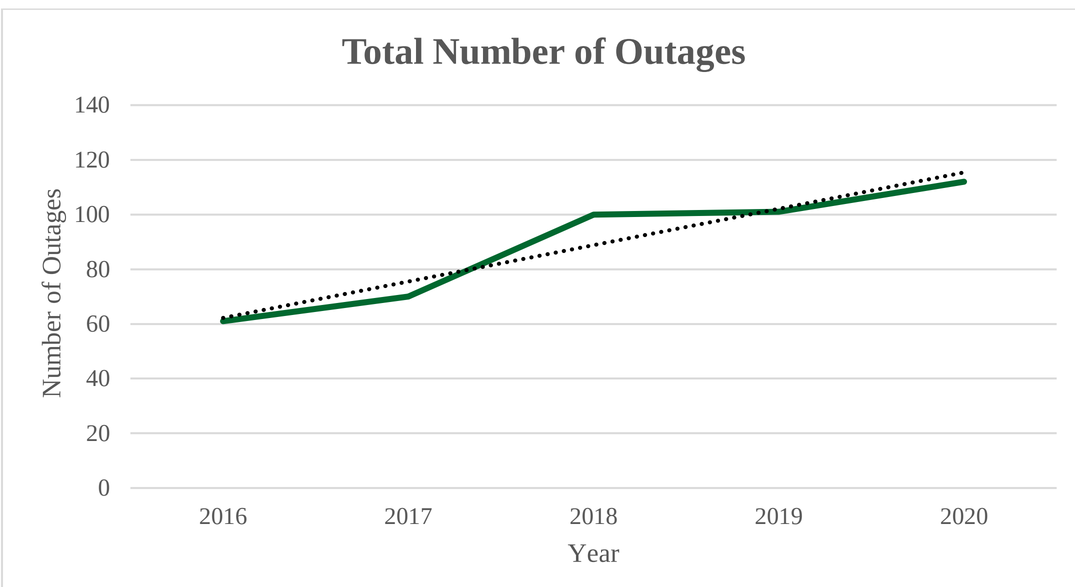
In addition to employing key reliability indicators to monitor its overall system reliability level, E.L.K. also tracks outage statistics including root causes on a regular basis. This data is collected through trouble reports. Together with key reliability indicators, these statistics provide valuable insight to the root causes for system outages and enable E.L.K. to target specific areas in an effort to lower outage frequency and reduce lengths of outages.

Table 2-23 presents the count of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. E.L.K. continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 2-23: Number of Outages by cause codes (Excluding Major Event Days)

Cause Code	2016	2017	2018	2019	2020	Total Outages	Percent Share
0-Unknown/Other	1	8	6	3	8	26	5.86%
1-Scheduled Outage	9	8	24	8	4	53	11.94%
2-Loss of Supply	1	0	7	7	11	26	5.86%
3-Tree Contacts	2	3	16	12	14	47	10.59%
4-Lightning	5	3	0	3	3	14	3.15%
5-Defective Equipment	27	28	25	43	40	163	36.71%
6-Adverse Weather	1	6	7	4	7	25	5.63%
7-Adverse Environment	1	1	1	2	1	6	1.35%
8-Human Element	1	0	1	0	0	2	0.45%
9-Foreign Interference	13	13	13	19	24	82	18.47%
Total	61	70	100	101	112	444	100%

Figure 2-2: Total Number of Outages



The total number of interruptions over the historical period varies from a low of 61 to a high of 112, with the overall trend increasing in the period. This represents an average of 0.167 to 0.307 interruptions per day. The increasing trend indicates that improved System Renewal is required over the forecast period to allow E.L.K. to better manage the number of interruptions it has control of. We are responding to E.L.K. customers concerns that have been communicated to us via our survey and published in the media (referenced by the Town of Kingsville and councillors).

System Service

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet its operational objectives, while being able to anticipate future customer electricity requirements.

The main investment activity comprising System Service for E.L.K. within this DSP is the installation and deployment of fault circuit indicators onto the distribution lines in E.L.K. service territories. E.L.K. forecasts deploying ten sets of fault circuit indicators per year starting with a test year in Kingsville service territory. These fault indicators will allow for more accurate visibility on faults within the distribution system to identify targeted areas for power service restoration and monitoring.

General Plant

Expenditures in the General Plant category are driven by the need to modify, replace or add to assets that are not part of the distribution system but support E.L.K.'s daily operations. The items within this category are important and contribute to the safe and reliable operation of a distribution system. If General Plant investments are ignored or deprioritized this could lead to future operational risks or increased investments in future years.

The main investment activity with the General Plant category will be the procurement of two large new fleet vehicles for the E.L.K. fleet. Previous units have reached end of useful life and need to be replaced, which leads to the large capital investments in 2022 and 2023. Procurement and delivery of the chassis of the vehicle is expected in 2022, with the final delivery of the body of the vehicle anticipated in 2023. The delivery of these fleet vehicles will allow E.L.K. to safely operate and maintain the distribution system across its service territories. In addition, supported by feedback from customers, E.L.K. will be undertaking a comprehensive review and upgrade of various IT systems. The IT strategy is planned to include a new GIS system, integration of an Outage Management System (OMS), a new refreshed E.L.K. website in 2022 and implementation of Green Button in 2022, and the generation of Outage Maps for E.L.K. customers. These are considered fundamental systems that are required to track and monitor important information about assets and the overall system. This is also considered good utility practice as demonstrated by the implementation of similar systems by other distribution companies in Ontario and beyond.

For more detail, please refer to E.L.K.'s DSP in Exhibit 2, Tab 4, Attachment 1.

4.4 SUMMARY OF CAPITAL PROJECTS

Table 2-24 (Chapter 2 Appendix 2-AA) below presents a summary of all gross capital expenditures by project for the historical period 2012, 2016 to 2020, the 2021 Bridge Year and 2022 Test Year.

Table 2-24 Capital Projects

Appendix 2-AA
Capital Projects Table

Projects	2012	2016	2017	2018	2019	2020	2021 Bridge Year	2022 Test Year
Reporting Basis								
Project Name #1								
Underground/OH Asset Renewal	206,859	213,509	173,525	513,402	45,385	491,842	420,000	190,000
Sub-Total	206,859	213,509	173,525	513,402	45,385	491,842	420,000	190,000
Project Name #2								
FIT Contributions	60,300							
Sub-Total	60,300	0	0	0	0	0	0	0
Project Name #4								
Smart Meters	57,319							
Sub-Total	57,319	0	0	0	0	0	0	0
Project Name #5								
Comber Solar	67,810							
Sub-Total	67,810	0	0	0	0	0	0	0
Project Name #6								
Cooper Estates Ph 4B	66,701							
Sub-Total	66,701	0	0	0	0	0	0	0
Project Name #7								
Cottam Woods Solar	125,965							
Sub-Total	125,965	0	0	0	0	0	0	0
Project Name #8								
Townsview Ph 3	52,865							
Sub-Total	52,865	0	0	0	0	0	0	0
Project Name #14								
Kingsville Commercial Developm	62,729							
Sub-Total	62,729	0	0	0	0	0	0	0
Project Name #28								
Amico Properties - ROATC Ph 5		130,633						
Sub-Total	0	130,633	0	0	0	0	0	0
Project Name #29								
Cottam Woods Ph 3A		94,130						
Sub-Total	0	94,130	0	0	0	0	0	0
Project Name #30								
Belle River Public		16,062						
Sub-Total	0	16,062	0	0	0	0	0	0
Project Name #31								
Belle River High		19,293						
Sub-Total	0	19,293	0	0	0	0	0	0

Appendix 2-AA
Capital Projects Table

Projects	2012	2016	2017	2018	2019	2020	2021 Bridge Year	2022 Test Year
Reporting Basis								
Project Name #32								
Harrow Senior Public		16,062						
Sub-Total	0	16,062	0	0	0	0	0	0
Project Name #33								
Town of Essex Sanitary Pump		87,841						
Sub-Total	0	87,841	0	0	0	0	0	0
Project Name #34								
Sellick		83,796						
Sub-Total	0	83,796	0	0	0	0	0	0
Project Name #35								
Brady & Vella's Professional		45,375						
Sub-Total	0	45,375	0	0	0	0	0	0
Project Name #36								
225 Prince Albert		46,947						
Sub-Total	0	46,947	0	0	0	0	0	0
Project Name #37								
141 Main St E- Gary Anthony		13,359						
Sub-Total	0	13,359	0	0	0	0	0	0
Project Name #38								
1156722 Ont Limited- Bernath			197,300					
Sub-Total	0	0	197,300	0	0	0	0	0
Project Name #39								
Hopgood Developments- Brotto			61,645					
Sub-Total	0	0	61,645	0	0	0	0	0
Project Name #40								
Colio			86,677					
Sub-Total	0	0	86,677	0	0	0	0	0
Project Name #41								
Kimball Estates Ph 5			151,527					
Sub-Total	0	0	151,527	0	0	0	0	0
Project Name #42								
Amico Properties- ROATC 8B			117,075					
Sub-Total	0	0	117,075	0	0	0	0	0
Project Name #43								
Townsview Ph 4				125,465				
Sub-Total	0	0	0	125,465	0	0	0	0

Appendix 2-AA
Capital Projects Table

Projects	2012	2016	2017	2018	2019	2020	2021 Bridge Year	2022 Test Year
Reporting Basis								
Project Name #44								
Amico Properties- ROATC 9				176,744				
Sub-Total	0	0	0	176,744	0	0	0	0
Project Name #45								
6 Park				82,016				
Sub-Total	0	0	0	82,016	0	0	0	0
Project Name #46								
Car Wash & Valvoline				47,501				
Sub-Total	0	0	0	47,501	0	0	0	0
Project Name #47								
Kingsville Condo				78,575				
Sub-Total	0	0	0	78,575	0	0	0	0
Project Name #48								
Town of Kingsville 103 Park				47,485				
Sub-Total	0	0	0	47,485	0	0	0	0
Project Name #49								
106 Wigle					43,580			
Sub-Total	0	0	0	0	43,580	0	0	0
Project Name #50								
Forest Hills Ph 4A					352,267			
Sub-Total	0	0	0	0	352,267	0	0	0
Project Name #51								
Southpoint					42,408			
Sub-Total	0	0	0	0	42,408	0	0	0
Project Name #52								
Canadian Tire A & W					39,571			
Sub-Total	0	0	0	0	39,571	0	0	0
Project Name #53								
Townsview Ph 5					135,870			
Sub-Total	0	0	0	0	135,870	0	0	0
Project Name #54								
2243893 Ont Ltd (Tracey)					213,324			
Sub-Total	0	0	0	0	213,324	0	0	0
Project Name #55								
Alium Investments					48,034			
Sub-Total	0	0	0	0	48,034	0	0	0

Appendix 2-AA
Capital Projects Table

Projects	2012	2016	2017	2018	2019	2020	2021 Bridge Year	2022 Test Year
Reporting Basis								
Project Name #56								
Jakana Ph 3B - I						108,300		
Sub-Total	0	0	0	0	0	108,300	0	0
Project Name #57								
Jakana Ph 3B - II						48,510		
Sub-Total	0	0	0	0	0	48,510	0	0
Project Name #58								
Kingsville Medical						98,537		
Sub-Total	0	0	0	0	0	98,537	0	0
Project Name #59								
Westons						73,581		
Sub-Total	0	0	0	0	0	73,581	0	0
Project Name #60								
Crawford Packaging						46,166		
Sub-Total	0	0	0	0	0	46,166	0	0
Project Name #61								
Anderdon -230 Centre St						202,885		
Sub-Total	0	0	0	0	0	202,885	0	0
Project Name #62								
Woodbridge Ph 1						140,879		
Sub-Total	0	0	0	0	0	140,879	0	0
Project Name #63								
Transportion Truck					110,750	471,000		
Sub-Total	0	0	0	0	110,750	471,000	0	0
Project Name #64								
Jasperson Relocation							7,176	
Sub-Total	0	0	0	0	0	0	7,176	0
Project Name #65								
MTO HWY 3- Maidstone Relocation							54,669	
Sub-Total	0	0	0	0	0	0	54,669	0
Project Name #66								
Service Connections	72,965					153,959	126,696	180,000
Sub-Total	72,965	0	0	0	0	153,959	126,696	180,000
Project Name #67								
MTO HWY3 South Talbot							57,949	
Sub-Total							57,949	

Appendix 2-AA
Capital Projects Table

Projects	2012	2016	2017	2018	2019	2020	2021 Bridge Year	2022 Test Year
Reporting Basis								
Project Name #68								
MTO HWY3 Victoria Crossing							210,557	
Sub-Total							210,557	
Project Name #69								
Fleet Replacement							423,615	370,000
Sub-Total	0	0	0	0	0	0	423,615	370,000
Project Name #70								
Essex Town Center							128,000	219,000
Sub-Total	0	0	0	0	0	0	128,000	219,000
Project Name #71								
Tracey Comber Phase 2								95,000
Sub-Total	0	0	0	0	0	0	0	95,000
Project Name #72								
Woodbridge Phase 2							0	60,000
Sub-Total	0	0	0	0	0	0	0	60,000
Project Name #73								
Cottam Ridge Armstrong Sub							0	100,000
Sub-Total	0	0	0	0	0	0	0	100,000
Project Name #74								
Viscount Road Primary Cable Upgrade							0	40,000
Sub-Total	0	0	0	0	0	0	0	40,000
Project Name #75								
Gosfield/Maidstone Intersection Work								140,000
Sub-Total	0	0	0	0	0	0	0	140,000
Miscellaneous	11,101	131,852	28,040	33,850	63,381	-78,620	131,847	124,000
Total	**784,614**	**898,857**	**815,789**	**1,105,038**	**1,094,569**	**1,757,039**	**1,293,003**	**1,634,000**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***								
Total	**784,614**	**898,857**	**815,789**	**1,105,038**	**1,094,569**	**1,757,039**	**1,293,003**	**1,634,000**

Capital Expenditure variances for the 5 historical years 2016-2020, Bridge Year 2021 and Test Year 2022 above are provided in Table 2-25.

Table 2-25 Captial Expenditure Variances

Capital Expenditures	2012 OEB-Approved	2016 Actuals	2017 Actuals	2018 Actuals	2019 Actuals	2020 Actuals	2021 Bridge Year	2022 Test Year
Capital Expenditures	1,187,103	898,857	815,789	1,105,038	1,094,569	1,757,039	1,628,000	1,634,000
Variance - vs. previous year			-83,068	289,249	-10,469	662,470	-129,039	6,000

The decrease in the 2021 Bridge Year over 2020 Actuals of $129,039 is primarily driven by a decrease in capital projects relative to higher-than-average capital expenditures in 2019. In particular, transportation equipment expenditures decreased by $362,380, following truck purchases which were delayed from 2019 to 2020, and decreases to underground conduit, conductors and devices spending (-$100,867). These decreases were partially offset by increases in line transformers ($215,768) and poles, towers and fixtures ($200,158).

The increase in the 2022 Test Year over 2021 Bridge Year of $6,000 is primarily driven by increased growth in E.L.K.'s service areas and E.L.K.'s efforts to smooth capital spending in the 2022-2026 period. Material variances from 2021 to 2022 include increases in transportation equipment ($325,000) and decreases to line transformers (-$182,000) and poles, towers and fixtures (-$88,000).

4.5 PROJECTS WITH A LIFE CYCLE GREATER THAN ONE YEAR

E.L.K.'s accounting policy is to include projects in Fixed Assets when they are completed and put into service. Capital projects which are not yet completed are included in WIP. Capital projects with a life cycle greater than one year will be carried over from one year to the next in WIP. Once completed expenditures are removed from WIP and capitalized to fixed assets at which point they begin depreciating.

4.6 TREATMENT OF COST OF FUNDS

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Corporation's borrowings. Qualifying assets are considered to be those that take in excess of nine months to construct.

4.7 COMPONENTS OF OTHER CAPITAL EXPENDITURES – NON DISTRIBUTION

E.L.K. does not have other capital expenditures, such as non-distribution activities, for which it needs to provide components.

4.8 EFFICIENCIES REALIZED DUE TO DEPLOYMENT OF SMART METERS AND RELATED TECHNOLOGIES

E.L.K. has made use of both E.L.K. Operational Data Storage (Metersense) as well as the Sensus Meter website to allow E.L.K. to investigate meter issues as well as work and analyze the MDM/R reports on a daily basis. These two tools also allow E.L.K.'s customer service representatives to check customer's power on demand. This has resolved some customer inquiries immediately instead of requiring a field visit to verify power conditions. 2022 will see the upgrade of demand-reading equipment to cloud-based technology to further provide efficiencies in the billing process.

4.9 CONSERVATION INITIATIVES

Although E.L.K. has had consistent growth in its customer base or service territory, it has not experienced a tremendous material growth, thus, E.L.K. has not had the need to consider incremental conservation initiatives to defer or otherwise avoid future infrastructure projects. This will likely remain true over the life of this Application. E.L.K. is not applying for funding through distribution rates to pursue any custom type energy efficiency programs.

Distribution System Plan

Developed in accordance with:

"Ontario Energy Board – Filing Requirements for Electricity Transmission and Distribution Applications"

Chapter 5

Consolidated System Plan Filing Requirements

Historical Period:

2017 - 2021

Forecast Period:

2022 - 2026

TABLE OF CONTENTS

Contents

5.1 INTRODUCTION

E.L.K. Energy Inc. (E.L.K.) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) *Chapter 5 - Consolidated Distribution System Plan Filing Requirements*, dated June 24, 2021 (the "Filing Requirements") as part of its 2022 Cost of Service Application (the Application). E.L.K. Energy Inc. (E.L.K.) retained METSCO Energy Solutions Inc. (METSCO) to advise on and assist with the preparation of the DSP.

5.1.1 Objectives and Scope of Work

DSP Addresses Four Outcomes

DSP filings must support the Board's assessment as to whether a distributor has and will continue to achieve the four performance outcomes the Board has established for electricity distributors as explained below. Section 5.4.5 explains the specific criteria the Board will use to evaluate whether a DSP and in particular the material projects/activities proposed for cost recovery in a DSP address these four outcomes.

Customer Focus

A DSP filing must demonstrate that distribution services are provided in a manner that responds to identified customer preferences. As indicated in the provisions that follow, this is accomplished by providing information on customer engagement to identify preferences; the value proposition the DSP represents for customers (economic efficiency and cost-effectiveness); and on the factors relating to customer preferences or input from customers and participants in a Regional Planning Process that were considered in the course of planning investment projects and activities.

Operational Effectiveness

DSPs must show that a distributor's asset management and capital expenditure planning processes are designed to identify and take advantage of opportunities for continuous improvements in productivity and cost performance, while delivering on a distributor's explicitly stated system reliability and quality objectives.

Public Policy Responsiveness

A distributor's DSP must explain how the expenditure planning process has been integrated and rationalized so as to permit timely and appropriate expenditures in relation to a distributor's government-mandated obligations (e.g., in legislation or regulatory requirements imposed further to Ministerial directives to the Board).

Financial Performance

DSPs must show that a distributor's financial viability and operational effectiveness will endure over the long-term including by sustaining efficiencies gained through prudent capital-related expenditure planning and DSP execution.

Based on historical trends and achievements, E.L.K. is shaping its future plans and investment decisions to address OEB expectations in the following areas:

- Customer Focus
- Financial Performance and Economic Efficiency Performance
- Public Policy Responsiveness, Health & Safety and Environmental Performance
- Operational Effectiveness, Reliability, Consistency, and Improvement

5.1.2 Outline of the Report

The report is organized using the Ontario Energy Board's Chapter 5 - Consolidated Distribution System Plan Filing Requirements dated 24 June 2021, included in the Filing Requirements for Electricity Transmission and Distribution Applications (the "Filing Requirements"). The report is organized into four sections, including this introductory section. Section 5.2 provides an overview of the Distribution System Plan and describes the process employed in its development, i.e., stakeholder consultations, collaboration with municipal/regional governments and transmitters, performance measurements and monitoring metrics. Section 5.3 describes in detail the asset management process employed to determine the scope of capital investments into asset sustainment and prioritize these investments into various assets. Section 5.4 documents the overall capital expenditure plan covering System Access, System Renewal, System Service, as well as capital investments into General Plant upkeep and investments into provincially mandated programs to facilitate smart grid, CDM and Green Energy connections during the next five years. Cross references to the Filing Requirements are included in brackets () at all headings/subheadings within this report for ease of reference.

5.1.3 Description of the Utility Company

E.L.K. supplies electrical service to customers within the former municipalities of Belle River, Comber, Cottam, Essex, Harrow and Kingsville. E.L.K. has over 12,400 customers as of the December 2021, including over 11,076 residential customers, with a service territory of 23 sq. km. All of E.L.K.'s service territories are embedded within Hydro One Networks Inc. ("Hydro One"). The map in Figure 5.1-1 depicts E.L.K.'s service territory boundaries.

Figure 5.1-1: E.L.K. Service Territory

E.L.K. owns, maintains, and operates approximately 89 km of overhead primary distribution feeders and 79 km of underground primary distribution circuits including seven 27.6 kV feeders and one 8.32kV feeders. Bulk power system supply is provided by four Hydro One owned transformer stations.

5.1.3.1 Mission, Vision, and Core Values Statement

VISION/MISSION/TACTICS

E.L.K.'s vision is "An Energy Company Powering Sustainable Communities".

Mission

E.L.K.'s mission statement is to provide the highest quality service to our customers by ensuring that the electrical system is designed, constructed and maintained to ensure its reliability, safety and affordability while increasing shareholder value.

Core Objectives

E.L.K.'s priorities are defined in its Corporate Goals

- Provide a safe and reliable electricity distribution system with the capacity to meet the expectations of our customers and support local economic growth.
- Promote and practise excellence in safety.
- Provide quality customer support and encourage customer feedback in order to improve customer satisfaction.
- Establish the lowest retail rates possible without compromising the financial integrity of the Corporation in compliance to our Shareholder's direction and Corporate Strategic Plan.

This application is consistent with E.L.K.'s Corporate Mission and Corporate Goals as outlined below. E.L.K.'s rate application and distribution system plan will ensure success is maintained by:

1. Creating sustainable value for our shareholder by promoting business strengths and pursuing appropriate business opportunities.
2. Keeping up to date on regulatory and provincial changes
3. Regularly review the fixed assets and the Distribution System Plan
4. Continued Technological advancements to optimize effectiveness and efficiency.
5. Strong and effective fiscal management.

GOVERNANCE

Figure 5.1-2 is the corporate structure of E.L.K. Energy Inc. E.L.K. holds monthly Board Meetings. The E.L.K. Board is appointed by E.L.K.'s shareholder. The Corporation of the Town of Essex identifies and selects new members of the Board.

E.L.K.'s Board of Directors consists of nine directors, none of which is an employee or officer of the utility. Of the nine directors, four are independent, and do not sit on the Board of any E.L.K. affiliate. This conforms to the Affiliate Relationship Code ("ARC") whereby at least one-third of its directors must remain independent from Affiliate Boards. There is one regular committee of the E.L.K. Board, that being the Finance Committee.

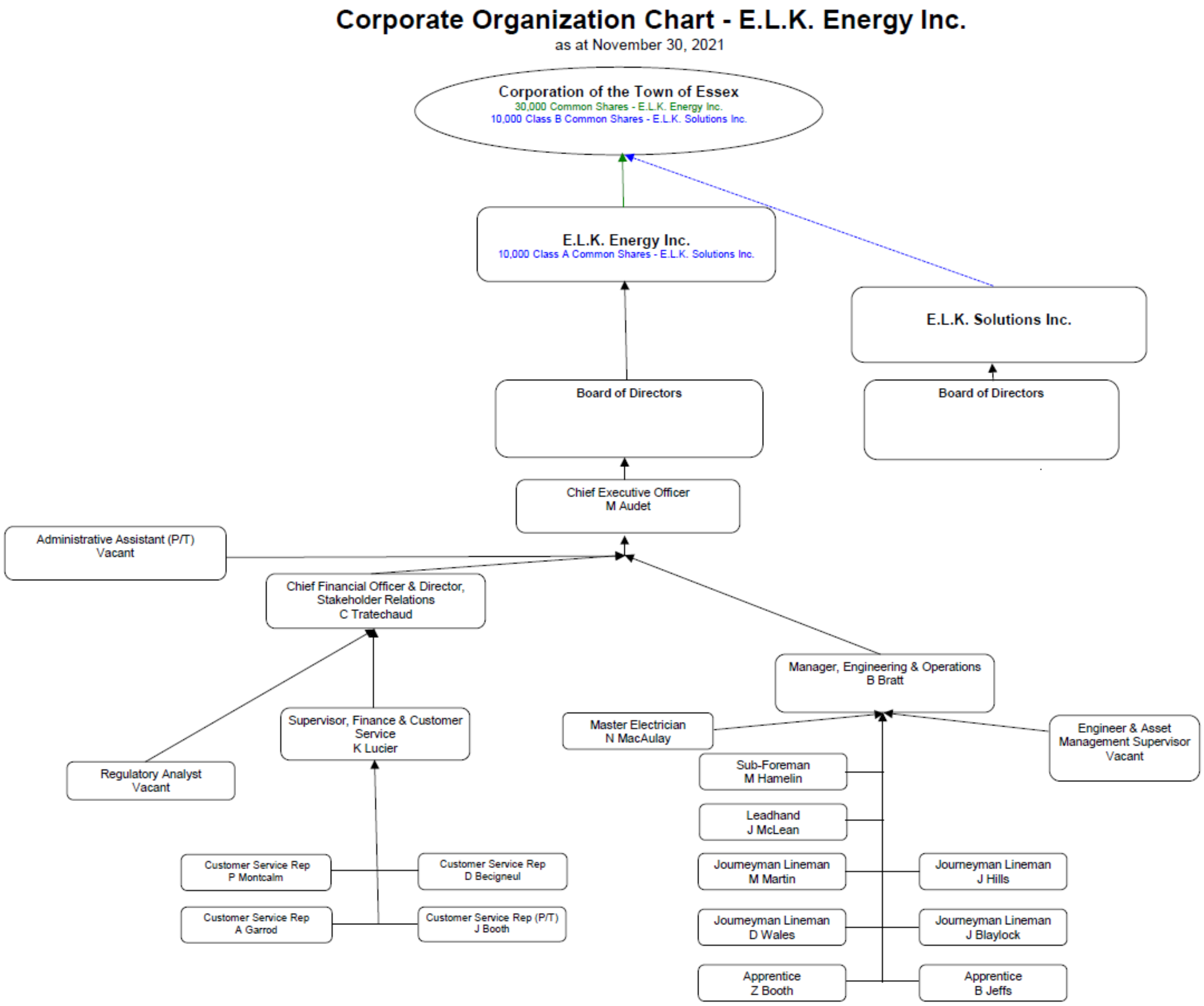


Figure 5.1-2: E.L.K.'s Corporate Structure

5.1.3.2 Customers Served

In 2020, E.L.K. served 12,611 electricity distribution customers across its service area. Table 5.1-1 illustrates a slight increasing trend in E.L.K.'s customer base over the historical period, divided into residential, general service less than 50 kW, and general service greater or equal to 50 kW.

Table 5.1-1: Changing Trends in E.L.K.'s Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2020	11,076	1,436	99	12,611
2019	10,963	1,418	97	12,478
2018	10,882	1,406	123	12,411
2017	10,800	1,418	126	12,344
2016	10,312	1,381	101	11,794

5.1.3.3 System Demand and Efficiency

Table 5.1-2 shows the annual peak demand for summer and winter, in kilowatts (kW), as well as the average annual peak from 2016 to 2020. E.L.K. experiences its overall system peak during the summer months.

Table 5.1-2: Peak System Demand Statistics

Annual Year	*Winter Peak (kW)*	*Summer Peak (kW)*	*Average Peak (kW)*
2020	42,657	64,724	46,553
2019	50,790	62,827	48,506
2018	47,848	65,612	51,085
2017	44,168	57,221	45,399
2016	46,645	60,936	47,467

Table 5.1-3 indicates the efficiency of the kilowatt hour purchased by E.L.K.

Table 5.1-3: Efficiency of kWh purchased by E.L.K.

Annual kWh Purchased	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2020	232,532,801	245,634,676	5.33%
2019	243,325,668	248,931,820	2.25%
2018	246,050,638	252,552,933	2.57%
2017	222,884,140	236,059,300	5.58%
2016	238,667,221	244,970,130	2.57%

5.1.4 Background Drivers

The Filing Requirements outline four categories of investments into which projects and programs must be grouped. The drivers for each investment category align with those listed in the Filing Requirements. For reporting purposes, a project or program involving two or more drivers associated with different categories is included in the category corresponding to the trigger driver. To note, all drivers of a given project or program were considered in the analysis of capital investment options and are further described in Section 5.4 of the DSP

5.1.4.1 System Access

These investments are modifications (including asset relocation) to the distribution system E.L.K. is obligated to perform to provide a customer or group of customers with access to electricity services via E.L.K.'s distribution system.

5.1.4.2 System Renewal

These investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of E.L.K.'s distribution system to provide customers with reliable and safe electricity services.

5.1.4.3 System Service

These investments are modifications to E.L.K.'s distribution system to ensure the distribution system continues to meet E.L.K.'s operational objectives while addressing anticipated future customer electricity service requirements. E.L.K. is planning on installing fault circuit indicators across its network over the next five years, to allow it to better manage outages and pinpoint areas that are causing these outages.

5.1.4.4 General Plant

These investments are modifications, replacements, or additions to E.L.K.'s assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock; fleet vehicles; and electronic devices and software used to support day-to-day business and operations activities.

5.2 DISTRIBUTION SYSTEM PLAN

Section 5.2.1 provides an overview of the DSP. Section 5.2.2 summarizes coordinated planning activities with third parties. Section 5.2.3 covers the performance measurement approach to continuously improve asset management and capital expenditure planning processes. Finally, summarizes the realized efficiencies from smart meters.

5.2.1 Distribution Plan Overview

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to E.L.K. Distribution's asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

5.2.1.1 Key Elements of the DSP

E.L.K.'s DSP is a comprehensive collaboration of information with inputs from numerous sources starting from our core business objectives, asset management objectives and performance evaluation, and our consultation with major stakeholders. The drivers are addressed under the headings of System Access, System Renewal, System Services and General Plant. The planning objectives and processes are explored in detail in Section 5.4.2.1, but in summary include:

- Ensure proper allocation of investments to meet regulatory obligations;
- Ensure adequate level of investment in the renewal of distribution system assets;
- Determine the acceptable level of expenditures required to meet existing and future demand levels;
- Ensure proper allocation of investments in General Plant assets; and
- Determine impacts to financials and adjust spending as required.

The output of this process is a sustainable, levelized five-year capital plan for the forecast period. The DSP was developed with the objective, to not only address the identified short- and mid-term issues on the distribution system, but also to prepare for foreseeable future changes and requirements on the system to achieve sound and effective financial planning in the long term. The table below presents E.L.K.'s historical actuals and forecast expenditures for both capital and O&M categories. E.L.K.'s 2021 expenditures are projected actuals for projects on track for completion in 2021, however, values are not final and may still change upon year completion.

Table 5.2-1: Historical Actuals and Forecast Capital Expenditures and System O&M

Category	Historical ($ '000)					Forecast ($ '000)				
	2017	2018	2019	2020	2021*	2022	2023	2024	2025	2026
System Access (Gross)	614	558	875	726	659	867	943	1,108	1,144	1,183
System Renewal (Gross)	174	513	45	492	152	307	370	452	494	539
System Service (Gross)	0	0	0	0	0	42	42	42	42	83
General Plant (Gross)	28	34	174	539	474	419	609	244	227	56
Gross Capital Expenses	**816**	**1,105**	**1,094**	**1,757**	**1,286**	1,634	1,963	1,845	1,907	1,862
Contributed Capital	(243)	(173)	(702)	(530)	(468)	(468)	(477)	(487)	(497)	(506)
Net Capital Expenses after Contributions	573	932	393	1,227	818	1,166	1,486	1,358	1,410	1,355
System O&M	910	969	1,086	864	925	1,447	1,476	1,505	1,535	1,566

**Estimated actuals up to December 10, 2021.*

5.2.1.1 System Access

System Access investments are modifications to the existing system that will allow E.L.K. to provide future customers with access to its electricity services. These investments are often trigged by customer requests and are completed to fulfill E.L.K.'s service obligations to other third parties. For E.L.K., System Access investments in historic years typically include:

- Connecting new customers;
- Line relocations; and
- Metering projects.

For this planning cycle, System Access activities are projected to continue as per previous years. Residential subdivisions, line relocations due to municipal driven activities and connections make up the bulk of activities in this area.

5.2.1.2 System Renewal

System Renewal investments involve replacement and refurbishment of system assets to maintain the system's ability to provide reliable electricity services to customers. As assets become aged and reach end of useful life (EOL), these investments are necessary to rectify and maintain the overall asset health condition at an acceptable level to prevent decline in system reliability performance and mitigate safety risks to E.L.K. employees and the public.

E.L.K. reviews the asset data base and outage information for its key distribution system assets on an annual basis to identify problematic assets that have reached, or will be reaching, end of life in the near term. In addition, in 2020, E.L.K. engaged a third-party (EDM International, Inc) to undertake a pole testing review and Kinectrics to undertake an asset condition assessment (ACA) on E.L.K.'s other distribution assets. The outputs of these report and the additional review of the outage data available, the following assets will be targeted for replacement:

- Wood pole replacement;

- Pad and Pole mounted transformers; and
- Underground Cable Replacement.

E.L.K. will also consider replacing other distribution assets that have been classed as in Poor and Very Poor condition or have reached end of useful life or are obsolete.

E.L.K.'s decisions on asset replacement and refurbishment are based on asset conditions, age, outage statistics, corporate objectives, and customer preferences. Therefore, System Renewal investments proposed in this DSP include proactive replacements to address targeted assets identified through E.L.K.'s asset management and capital planning process.

5.2.1.3 System Service

System Service investments include upgrades or expansions of the existing system to support demand growth of existing customers or create flexibility to improve operation efficiency. E.L.K. is planning on installing fault circuit indicators across its network over the next five years, to allow it to better manage outages and pinpoint areas that are causing these outages. This will allow E.L.K. to identify areas that require further investment to improve the reliability of supply customers experience.

5.2.1.4 General Plant

General Plant investments are made to maintain assets that are not part of the distribution system but are used to support day to day business and operational activities. This generally includes:

- Land and buildings;
- Tools and equipment;
- Fleet of Vehicles;
- Information Systems Hardware; and
- Information Systems Software.

E.L.K. will continue to renew the fleet as described in the vehicle replacement program. In addition, E.L.K. has developed an IT strategy, that will include both the operations of E.L.K., but also provide customers with a better user experience. As supported by E.L.K. customer DSP engagement survey results, E.L.K. will look to integrate of a GIS system over the forecast period which would enable E.L.K. to capture and track asset data including age and condition information, interruption reports and field inspections geographically. Additionally, outage maps will be developed and easily accessible on its website. E.L.K. will also look to make incremental improvement to its website to allow for a more user-friendly experience. E.L.K. will continue to review its plan and ensure each investment is required before proceeding.

5.2.1.2 Customer Preferences and Expectations

E.L.K. customer engagement activities related to this DSP took place in October and November 2021, through the issuance of a customer survey. The survey presented the general plans for each investment category and asked participants to select areas of the business for targeted improvements or investments that were a priority for customers. Some key findings were observed in the customer survey:

- E.L.K. asked about overall satisfaction with service provided and overall satisfaction with reliability of power provided by the distributor. Only 44% of respondents selected “very satisfied” or “somewhat satisfied” for overall satisfaction of service provided. With regards to reliability of service provided by E.L.K., only 36% of respondents were “very satisfied” or “somewhat satisfied”.

- Written feedback in the survey indicated a customer preference for improvement to reliability, outage notification, and a reduction in the flickering of service or brownouts.

- There was particular focus on reliability issues in the Kingsville and Essex service areas, although these are the two most highly populated service areas for E.L.K. and represented the greatest number of survey participants.

- Participants were in favour of increasing capital investment in System Renewal to improve reliability at 57% and were also in favour of increasing capital investment in General Plant to support the execution of System Renewal and system operating activities at 78%.

In addition to the completion of this customer survey, E.L.K. participated in annual customer satisfaction and customer safety surveys executed through a third-party vendor. The results of those annual surveys along with the customer survey targeted towards investments identified in this DSP, help to inform the capital planning decisions E.L.K. will pursue in this DSP application as they align with the priorities identified in the feedback from customers.

Below are the top customer priorities identified through these engagements:

1) Ensure reliable electric service
2) Deliver electricity at reasonable prices
3) Prioritize investments that will help improve system reliability, power quality, utility efficiency and operations.
4) Reduce the overall number of outages

E.L.K. believes that the investments proposed in this DSP are well aligned with customer preferences and needs. Initiatives supporting an improved reliability of service include the proactive replacement of equipment that is at increased risk of failure. Project examples are in the System Renewal investment category:

- SR-1: Pole Replacement Program
- SR-2: Transformer Replacement Program

In addition, E.L.K. is planning to deploy a fault indicator program in order to obtain real time information and more accurate visibility on faults within the distribution system to identify targeted areas for power service restoration. This technology will allow E.L.K. to monitor and manage unplanned outages more effectively. E.L.K. is planning to deploy the first sets of fault indicators within the Kingsville region due to known reliability concerns in the area. E.L.K. will then roll out deployment of the fault indicators across its other five regions.

In order to improve communications, outage notifications and overall customer satisfaction, E.L.K. will be undertaking a comprehensive review and upgrade of various IT systems over the forecast period. The IT strategy is planned to include a new GIS system, integration of an Outage

Management System (OMS), improvements to E.L.K.'s website, and the generation of Outage Maps for E.L.K. customers.

Finally, the replacement of two end of life fleet vehicles with new and more reliable vehicles will allow E.L.K. to safely operate and more effectively maintain its distribution system.

5.2.1.3 Sources of Cost Savings Expected

The sustaining asset replacement programs identified in the System Access, System Renewal, and General Plant categories are expected to have a number of positive impacts on future O&M costs:

- Investment in vegetation management, such as tree-trimming, will help minimize the number of outages cause by tree contacts. This would in turn not only help with reliability of supply for customers but also will reduce costs associated with outage response and reactive replacement.
- Proactive pole replacement prior to failure of the in-service pole or associated components will reduce costs associated with outage response and reactive replacement. Reactive costs are typically higher than proactive costs. Historically this has had a big impact on the SAIDI and SAIFI numbers outside of loss of supply.
- The proactive replacement of pole-mount and pad-mount transformers either in poor or very poor condition and/or at or near TUL will reduce costs associated with outage response and reactive replacement. Historically this has had a big impact on the SAIDI and SAIFI numbers outside of loss of supply.
- The replacement programs allow for replacement of legacy units that can no longer be economically maintained. The type of replacement units now available results in a much less labour-intensive program of inspection and corrective maintenance as required, as opposed to the periodic preventive maintenance required for legacy assets.
- Standardized Designs save money both by reducing the engineering costs of the project as well as reducing installation costs and material stock costs. E.L.K. is part of the Utilities Standard Forum ("USF") group to standardize installation drawings for use in the projects in this DSP. It also allows for maintenance to be carried out in a safe and standardized method, rather than having to adapt for unique types of assets.
- E.L.K. will continue to offer and promote eBilling to maintain and potentially increase the number of customers using this billing option. This could in the future reduce the number of bills required to be printed and processed manually. This would free up existing resource to target other critical work.

5.2.1.4 Period Covered by the DSP

E.L.K.'s DSP includes 2017-2020 as the historical period, 2021 is the bridge year and 2022-2026 as the forecast period, with 2022 being the Test Year.

5.2.1.5 Vintage of the Information

The information is current as of December 15, 2021

5.2.1.6 Important Changes to Asset Management Process

Since E.L.K.'s last DSP filing in 2016, E.L.K. has made a number of changes to its asset management process to improve value to its customers. Key changes include:

Improved Asset Condition Data

E.L.K. retained Kinectrics to undertake a full and complete Asset Condition Assessment in 2020 (see Appendix A). The ACA provided Health Index information for E.L.K.'s key asset classes, except poles, and identified a plan of assets expected to require attention over a 10-year period. This in turn has resulted in a better understanding of System Renewal needs and was used to inform E.L.K.'s capital and maintenance plans over the forecast period.

E.L.K. retained EDM International to complete a pole inspection report in 2020 (see Appendix B). The findings of this report helped E.L.K. to better understand System Renewal needs relating to its population of poles and was used to inform E.L.K.'s planned pole replacements over the forecast period. As part of this initiative, EDM also introduced a longer-term pole inspection and treatment plan based on the inspection results and analysis of those results. As part of this new plan, pole inspections and treatments will be conducted annually to capture pole data for different areas (average 500 poles per year), to identify poles which may require replacement under System Renewal, and when possible, to extend the life of poles via different treatment and refurbishment methods.

Improved Maintenance Practices

E.L.K. has plans to improve its vegetation management program by outsourcing tree trimming to a third-party contractor. Presently, tree trimming is conducted on a 4-year cycle by internal resources. However, due to resource constraints, E.L.K. has not been able to meet its planned vegetation management targets in historical years. E.L.K. has decided to outsource tree trimming to a third-party contractor that will have the resources and capabilities to complete tree trimming on a 4-year cycle, which in turn, will help improve system reliability.

Improved Data Collection

E.L.K. is also taking steps to improve the collection, availability, granularity, quality and accuracy of asset data, and is making significant progress in digitizing asset data that is currently in paper form (e.g., field inspection forms). The 2020 ACA report noted several asset classes for which further data quality improvements are recommended to improve the generation and quality of asset Health Indices in future ACAs. E.L.K. plans to begin addressing these gaps over the forecast period(2022-2026) and will review progress annually.

Improved IT Strategy

In addition, E.L.K. has developed an IT Strategy that will allow it to track and monitor its network more efficiently and improve data and data analytics capabilities that will help inform E.L.K.'s asset management processes. E.L.K.'s IT Strategy, which E.L.K. plans to further develop and begin implementing over the forecast period, is planned to include a new GIS system, integration of an Outage Management System (OMS), improvements to E.L.K.'s website, and the generation of Outage Maps for E.L.K. customers. These are considered fundamental systems that are required to track and monitor important information about assets and the overall system. This is also considered good utility practice as demonstrated by the implementation of similar systems by other distribution companies in Ontario and beyond.

E.L.K.'s asset management process is detailed further in Section 5.3.

5.2.1.7 Aspects of DSP Relating to or Contingent upon Ongoing Activities or Future Events (5.2.1(g))

None of the investments proposed in the DSP are contingent upon the outcome of ongoing activities or future events. The level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of customer requests for new services and line relocates, but such deviations are expected to be minor and the overall expenditure level during the next five years is not expected to be significantly different from the previous five years, when adjusted for inflation. Since none of the investments involve addressing constraints in the transmission system or upstream distribution system, regional planning process is expected to have no material impacts on this distribution plan and proposed investments.

5.2.1.8 Grid Modernization, Energy Resource, and Climate Change Adaptation (5.2.1(h))

E.L.K. undertakes ongoing and proposed projects to address grid modernization, energy resources, and climate change adaptation. The following activity is planned to be undertaken by E.L.K.:

Smart Fault Indicator Installation – E.L.K. plans to deploy 60 sets (180 total units) of Hortsmann Smart Navigator fault indicator components to the overhead system across the 2022-2026 period. The utility will initially start installing these in the Kingsville service area before extending to its other service areas. These fault indicators provide real time information to E.L.K. operations on fault detection, voltage interruption, current drop and increases in conductor temperature to inform reliability and restoration activities on E.L.K.'s system. This initiative contributes to the modernization of E.L.K.'s grid by allowing E.L.K. to access and analyze data and use that information to make the right decisions to ensure an efficient and reliable system. This initiative also aligns with the Long-Term Energy Plan (LTEP) goals of "Innovating to meet the Future" and "Improving Value and Performance for Consumers".

5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Summary of Consultation (5.2.2(a))

To meet the OEB's expectations with respect to coordinated planning with third parties, E.L.K. has initiated or participated in a consultation process with major stakeholders. This DSP considers the needs of its customers, the municipalities in the E.L.K. service territory, Hydro One Inc. (HONI), other LDCs within E.L.K.'s planning region, and the IESO. The DSP considers the outcomes of completed consultations, regional reports and plans, and continued coordination on future ongoing developments with third parties. The following sections describe each consultation activity E.L.K. participated in or led that was part of this DSP.

5.2.2.1.1 Customer Engagement

Customer Engagement Survey

E.L.K. is committed to sound financial planning and budgeting practices that balances quality electricity distribution services with affordability for ratepayers while fostering innovation and making investments in energy infrastructure that will benefit the community in the long term. To be able to abide by this commitment, E.L.K. is both proactive and reactive in its customer engagement consultations and engages its customers through multiple ongoing streams which include:

- In-person engagements at E.L.K.'s offices
- Social media platforms such as Twitter to bring attention to ongoing outages, restoration efforts and other topics of interest
- Phone calls through customer service to assist customers in addressing their needs and issues
- Website and email communication on important updates happening at E.L.K.
- Customer satisfaction surveys

Discussions through the consultations provide helpful insight into the day-to-day operations at E.L.K.

Over the historical period from 2016 to 2020, customer satisfaction surveys were completed in 2016, 2018 and 2020 to set benchmark customer satisfaction scores. The most recent customer survey completed in January 2020 was supported by OraclePoll Research Limited, and 400 respondents were involved. All respondents were screened to confirm that they were 18 years of age or older, E.L.K. customers and someone who is responsible for bill payments and making decisions about power bills. Overall satisfaction with E.L.K. as a utility service provider was at 81% good or very good, an improvement from 79% in 2018 and 75% in 2016. When asked to rate the reliability of power supply, 82% of customers rated reliability as good or very good, which is 2% higher compared to the previous poll in 2018 and 4% higher compared to the 2016 results. Communication and consultation with consumers in the 2020 survey were 60% good or very good, an improvement from 55% in 2018 and 49% in 2016. E.L.K. plans to continue maintaining their strong customer satisfaction metrics through similar consultation activities in future years and increasing the frequency of customer satisfaction engagements to occurring annually.

DSP Customer Engagement Survey

As part of this DSP application, E.L.K. has also initiated a separate customer survey, on its DSP, in November 2021 to obtain customer feedback on its forecast capital and operational spend for the forecast DSP period, including evidence of proposed scopes of work for System Renewal, General Plant and O&M. Information obtained from this survey showed support from customers on E.L.K.'s proposed capital and operational budgets plans, and system priorities identified in this DSP. Overall, 290 customers across E.L.K.'s six service areas responded.

Specifically, results showed that overall satisfaction around service provided to customers in the community was moderate, with 44% "very satisfied" or "somewhat satisfied". Specific feedback was targeted towards customers wanting improvements to reliability of service that E.L.K.

provides. Respondents rated “reducing the overall number of outages” as the highest priority with regards to reliability and “ensuring reliable electrical service” as the highest priority for E.L.K.’s ratepayer spending areas. To support the information within this DSP application, the majority of respondents, at 57%, wanted E.L.K. to increase the pace of System Renewal spending such that assets are replaced once in poor condition or past useful life, and 69% wanted E.L.K. to prioritize improvements that helped support system reliability. A detailed analysis of the results of this survey can be found in the E.L.K. Customer DSP Survey Report in Appendix C, which is the primary deliverable from E.L.K.’s customer engagement activities.

Below are the top customer priorities identified through these engagements:

1) Ensure reliable electric service
2) Deliver electricity at reasonable prices
3) Prioritize investments that will help improve system reliability, power quality, utility efficiency and operations.
4) Reduce the overall number of outages

The information and feedback obtained during customer engagements is one of the key inputs into E.L.K.’s asset management and distribution planning processes. E.L.K. plans to continue engaging with customers on an on-going basis over the forecast period and is hoping to improve engagements via a new website, improved outage communications (i.e., outage maps), and by increasing the frequency of its satisfaction surveys.

5.2.2.1.2 Consultation with Regional and Municipal Governments

Consultation and engagement with regional and municipal governments is important for the effective planning and operation of E.L.K.’s distribution system. E.L.K. engages with the municipalities of Lakeshore and Kingsville on an ad hoc basis to discuss ongoing plans, projects and/or engagements with their community members. In October 2021, E.L.K. also participated in engagements with Invest WindsorEssex, a not-for-profit organization supported by the City of Windsor and County of Essex with the goal of advancing the economic development in the region. There are no archived deliverables resulting from these engagements with municipalities or Invest WindsorEssex that are applicable to E.L.K. or this DSP application. These engagements with regional and municipal governments did not affect the drafting of this DSP application or the scope requested within it. E.L.K. intends to continue consulting with regional and municipal governments as required to remain informed on projects and initiatives within E.L.K.’s service area so that it can effectively plan and execute work in order to continue providing value to the communities and help them achieve their goals.

5.2.2.1.3 Regional Planning Process

The Regional Planning Process represents a coordinated, transparent, and cost-effective planning of electrical infrastructure at the regional level which was mandated by the OEB in 2013. To facilitate effective planning, the Province of Ontario is divided into 21 planning regions. As the lead transmitter, HONI conducts a Need Assessment (NA) and develops a Regional Infrastructure Plan (RIP) that involves representatives from the Independent Electricity System Operator (IESO), and Local Distribution Companies (LDCs) of the planning region.

E.L.K. is part of the Windsor-Essex planning region, shown in Figure 5.2-1. This region includes the municipalities of Amhurstburg, Essex, Harrow, Kingsville, Lakeshore, LaSalle, Leamington, Pelee Island, Tecumseh, and Windsor, as well as portions of Chatham-Kent. This planning region includes the following participants:

- Entegrus Powerlines Inc.
- Enwin Utilities
- Essex Powerlines Corporation
- E.L.K. Energy Inc.
- Hydro One Networks Inc. (HONI)
- Independent Electricity System Operator (IESO)

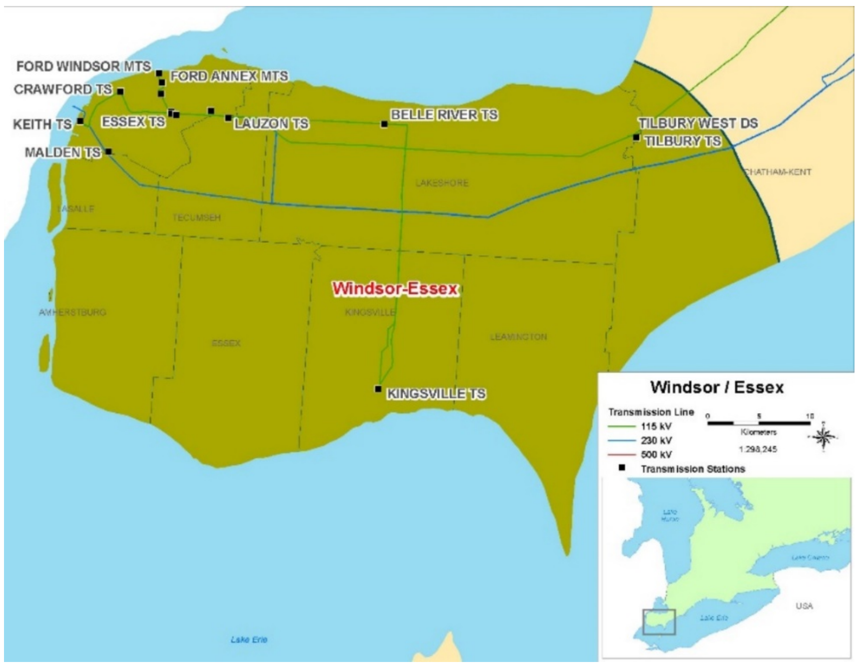


Figure 5.2-1: Windsor-Essex Planning Region[1]

The first regional planning cycle for the region was completed in December 2015 with the publishing of the Regional Infrastructure Plan (RIP), which identified needs and recommendations for the near- and medium-term timeframes.

The second regional planning cycle for the Windsor-Essex region was initiated in June 2017 with a Needs Assessment, which is in accordance with the Regional Planning process – that is the regional planning cycle should be revisited at least every five years. The Windsor-Essex Needs Assessment report was published by HONI in October 2017 (attached in Appendix D). This was followed by the Scoping Assessment in March 2018 (attached in Appendix E), completion of the Windsor-Essex IRRP in September 2019 (attached in Appendix F), and publication of the final RIP in March 2020 (attached in Appendix G).

Through the second regional planning cycle, a number of needs were identified in the Windsor-Essex region including station capacity needs, restoration needs and end-of-life needs. More

[1] Hydro One Networks Inc. Windsor-Essex Regional Planning.
https://www.hydroone.com/about/corporate-information/regional-plans/windsor-essex

specifically, the 2020 RIP provided the following summary of needs and recommended plans for Windsor-Essex region in the near- and mid-term (i.e., over the next 10 years):

- Supply capacity need to Kingsville-Leamington area, with a planned ISD between 2022 – 2025 and a budgetary estimate of $295M
    - Build new switching station at Leamington junction (Lakeshore TS), and new DESN station (South Middle Road TS)
    - Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS.
- Lauzon TS T5/T6 transformers end-of-life and station capacity, with a planned ISD in 2024 and a budgetary estimate of $34M
    - Replace Lauzon TS T5 & T6 transformers with larger 75/125 MVA units
- Belle River TS station capacity, with no planned ISD date or budgetary estimate included in the RIP
    - Monitor load growth and re-evaluate the need in the next regional planning cycle

E.L.K. customers are supplied via three Hydro One owned transformer stations(TS) and one distribution station (DS), including the Lauzon TS and the Belle River TS. Although needs and recommendations have been identified for these two stations, the actions identified do not directly impact E.L.K. and its current DSP.

Throughout the regional planning process E.L.K. provided forecast load data and the results of projects and programs that invest in the distribution system to the other parties engaged with during the regional planning exercise. E.L.K. will continue to actively participate in engagement with all relevant stakeholders for regional planning processes, and share information as required, to ensure it continues to respond appropriately to the needs of its customers and industry partners.

5.2.2.2 IESO Comment Letter on REG Investments **(5.2.2(d))**

The REG Investments Plan for the forecast period was prepared by E.L.K. and submitted to the IESO on 26 October 2021 as a final deliverable to forecast renewable generation connections on E.L.K.'s system. This report is presented in Appendix H, and the IESO Comment Letter is presented in Appendix I.

5.2.3 Performance Measurement for Continuous Improvement (5.2.3)

E.L.K. uses a set of performance measures to continuously monitor and evaluate its achievement with respect to the four performance outcomes established by the OEB particularly in respect of the Electricity Distributers Scorecard (Scorecard). Most of these measurements are required by the OEB for the DSP filing, while some are not. Regardless of requirement, these measurements are recorded as they are considered meaningful in the case of E.L.K.

The performance measures are outlined in Table 5.2-2 below.

Table 5.2-2: DSP Performance Measures for E.L.K. Energy

Performance Outcome	Measure	Motivation	Metric	Target
Customer-oriented performance	Service Quality	Regulatory/ Consumer	New Residential/Small Business Services Connected on Time	> 90%
			Scheduled Appointments Met on Time	> 90%
			Telephone Calls Answered on Time	> 65%
	Customer Satisfaction	Customer	First Contact Resolution	90%
			Billing Accuracy	98%
			Customer Satisfaction Survey	65%
	Customer Bill Impacts	Customer	Percentage Average Total Bill Impact	➢ 90%
			Average Dollar Impact	➢ 90%
	Power Quality	Customer	Power Quality and Electrical Disturbances	>90%
	System Reliability	Regulatory/ Customer	SAIDI	0.99
			SAIFI	0.34
Cost efficiency and effectiveness	Cost Control	Regulatory/ Customer/ Corporate	Efficiency Assessment	Maintain Group 1
			Total Cost per Customer	
			Total Cost per km of Line	
			Total Cost per Peak MW	
			Total CAPEX per Customer	
			Total CAPEX per km of Line	
			Total O&M per Customer	
			Total O&M per km of Line	
			Total O&M per Peak MW	
	Asset Management	Corporate/ Regulatory	DSP Implementation Progress	Completion
Asset/system operations performance	Safety	Regulatory/ Corporate	Level of Public Awareness	65%
			Level of Compliance with Ontario Regulation 22/04	C
			Serious Electrical Incident Index – Number of General Public Incidents	0
	Distribution Losses	Corporate	Line Losses	< 5%

5.2.3.1 Customer Oriented Preference (5.2.3(a))

5.2.3.1.1 Service Quality

5.2.3.1.1 (a) Methods and Measures

E.L.K. measures and reports on an annual basis on each of the service quality requirements set out in the Distribution System Code ("DSC"). Failure to meet minimum service quality targets would result in measures being taken to realign performance with DSC service quality standards. Service Quality measures include the following major measures: New Residential/Small Business Services Connected on Time, Scheduled Appointments Met on Time, and Telephone Calls Answered on Time.

New Residential/Small Business Connected on Time

The utility must connect new service for the customer within five business days 90% of the time unless the customer agrees to a later date. This timeline depends on the customer meeting specific requirements ahead of time (such as no electrical safety concerns in the building, customer's payment information complete, etc.). E.L.K.'s target is >=90%.

Scheduled Appointments Met on Time

For appointments during the utility's regular business hours, the utility must offer a window of time that is not more than four hours long and must arrive within that window 90% of the time. E.L.K.'s target is >=90%.

Telephone Calls Answered on Time

During regular call centre hours, the utility's call centre staff must answer phone calls within 30 seconds of receiving the call directly or of having the call transferred to them 65% of the time. E.L.K.'s target is >=65%.

5.2.3.1.1 (b) Historical Performance

Table 5.2-3 presents the service quality metrics tracked by E.L.K. along with E.L.K.'s historical performance records. E.L.K. has met the performance target for each performance metric during each of the past five years.

Table 5.2-3: Performance Measures – Service Quality

Measure	2016	2017	2018	2019	2020	E.L.K. Target
New Residential /Small Business Services Connected on Time	93.00%	94.44%	99.04%	98.34%	99.50%	90%
Scheduled Appointments Met on Time	98.90%	98.63%	100.00%	100.00%	99.07%	90%
Telephone Calls Answered on Time	97.20%	96.60%	96.25%	97.69%	95.08%	65%

5.2.3.1.1(c) Performance Trend into the DSP

E.L.K. exceeded the targets for each service quality measure. No new investments are proposed in this DSP in response to E.L.K.'s performance on this metric. E.L.K. continues to strive to better serve customers with the highest excellence.

5.2.3.1.2 Customer Satisfaction

5.2.3.1.2(a) Methods and Measures

E.L.K. measures and reports on Customer Satisfaction measures which include: First Contact Resolution, Billing Accuracy and Customer Satisfaction Survey Results. E.L.K. uses the OEB Targets for these measures and relies on its staff to meet these targets.

First Contact Resolution

E.L.K. 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 was not resolved at the first point of contact.

Billing Accuracy

E.L.K. 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 communicated on the customer's bill.

Customer Satisfaction

Customer satisfaction survey results and customer engagements are important to the success of E.L.K.. E.L.K. is proactive and reactive in its customer engagement consultations, the majority of which provide helpful insight into the day-to-day operations of E.L.K. The purpose of the survey is to focus on addressing issues of concern raised directly by customers. The survey asks questions of both residential and general service customers on a wide range of topics including power quality and reliability, price, billing payment, communications, and the customer service experience. The feedback is then incorporated into E.L.K.'s planning process and forms the basis of plans to improve customer satisfaction, meet the needs of customers, and address areas of improvement.

5.2.3.1.2(b) Historical Performance

E.L.K. sets a high standard for performance when it comes to customer care. E.L.K. strives to deliver customer excellence and value through the execution of its investments and operations. E.L.K. believes they have delivered the intended performance for each metric delivering customer satisfaction demonstrating credibility and trust.

Table 5.2-4: Performance Measures – Customer Satisfaction

Measure	2016	2017	2018	2019	2020	E.L.K. Target
First Contact Resolution	Excellent	Excellent	Excellent	Excellent	Excellent	--
Billing Accuracy	99.97%	99.99%	99.96%	99.96%	99.95%	98%
Customer Satisfaction Survey Results	88.00%	90.00%	90.00%	91.00%	91.00%	--

Overall, customer satisfaction increased from 88% in 2016 up to 91% in 2020, which indicates that customers are satisfied with E.L.K.'s service. The scores provide an indication that E.L.K. is actively listening to customer needs and providing service levels that meet their expectations. The results further indicate that E.L.K. is using strong business practices to provide a needed commodity reliably to a community that has an appreciation for the service being provided.

E.L.K.'s billing accuracy from 2016-2020 has been excellent, exceeding the target of 98% billing accuracy every year. This demonstrates that the technology and processes E.L.K. has in place are robust and efficient to enable E.L.K. to deliver accurate bills to its customers. In addition, E.L.K.'s performance related to resolving customers issues on first contact has been maintained at a high standard from 2016-2020 with it consistently being above 99.95%.

5.2.3.1.2(c) Performance Trend into the DSP

E.L.K.'s outstanding performance on the measures indicates no substantial additional material projects are required. E.L.K. continues to strive to better serve the customer with the highest excellence. E.L.K.'s intended action for the measure is to maintain the performance of the historical average. When developing the DSP, E.L.K. always considers its customers priorities and ensures that the investments it proposes will allow E.L.K. to continue to serve its customers as they expect. E.L.K. will continue to invest in its technology and people, as needed, to ensure it continues to provide a high standard of service of resolving customers issues at the first time of asking as well as maintain a high level of billing accuracy. Over the forecast period, E.L.K. is planning to better serve the customer via a new website, improved outage communications (i.e., outage maps), and by increasing the frequency of its satisfaction surveys.

5.2.3.1.3 Customer Bill Impacts

5.2.3.1.3 (a) Methods and Measures

Two measures can be used to quantify the impact of E.L.K.'s rate application on customers electricity bills:

- Percentage Average Total Bill Impact; and
- Average Dollar Impact.

Further information pertaining to the causes of these bill impacts can be found in Exhibit 8.

5.2.3.1.3(b) Historical Performance

In preparing this application, E.L.K. has considered the impacts on its customers, with a goal of minimizing those impacts. Table 1-10 in Exhibit 1 provides a summary of total bill impacts ($ and

%) for typical customers in all rate classes. These impacts reflect E.L.K.'s proposal for a two-year disposition period for deferral and variance accounts.

Table 5.2-5: Total Bill Impacts

Rate Class	Monthly kWh	Monthly kW	$ Change	% Change
Residential	750		-$1.60	-1.4%
General Service < 50 kW	2,000		-$1.91	-0.7%
General Service > 50 kW	75,000	200	-$475.65	-3.9%
Street Lights	15,583	45	$411.90	11.8%
Sentinel Lights	650		-$1.66	-1.9%
Unmetered Scattered Load	700	1.8	-$4.22	-4.3%
Embedded Distributor	1,000,000	2,000	-$1,080.80	-0.9%

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Disposition of deferral and variance accounts:
- Revised Retail Transmission rates;
- Wholesale Market Service rates; and
- Loss Factors.

5.2.3.1.3(c) Performance Trend into the DSP

This information is not a stand-alone metric. While customer bill impacts are important, customer feedback into other metrics and needs are also critical. The nature of customer input is there is some reluctance in accepting certain increases to bills in order to successfully see their energy needs met. Customers have also historically been interested in a well-functioning LDC providing their energy and this is taken into account when considering bill impacts. As much as E.L.K. would like to provide the lowest rates to its customers it also needs to provide safe and reliable service to customers. In the future, E.L.K. will continue to pursue various avenues to incorporate customer bill impacts into its distribution system planning process.

5.2.3.1.4 Power Quality

5.2.3.1.3 (a) Methods and Measures

In response to a customer power quality concern, where the utilization of electricity adversely affects the performance of electrical equipment, E.L.K. will perform an investigative analysis to attempt to identify the underlying cause. Depending on the circumstances, this may include review of relevant power interruption data and/or use of power and power quality measurement tools.

Connection of power measurement tools will be at the demarcation point or nearest safely accessible point of connection. Upon determination by E.L.K. that the power quality concern is deemed to be a system delivery issue where industry standards are not being met, E.L.K. will recommend and/or take appropriate mitigation measures. E.L.K. will use appropriate industry standards (such as International Electrotechnical Commission (IEC), Institute of Electrical and Electronics Engineers (IEEE), or CSA Group (CSA) standards) and good utility practice as a guideline. If the problem lies on the customer side of the system and, provided that the problem does not impact other customers connected to the system, E.L.K. will indicate as such to the customer, but take no further action.

Customers' electrical equipment can produce undesirable system disturbances that have an adverse impact on the distribution system. Customers are required to consult with E.L.K. when planning to install equipment that may cause disturbances. E.L.K.'s limits on voltage distortion are 3% for individual voltage harmonic distortion and 5% for total harmonic distortion. Given the nature of the concern, all power quality requests are investigated immediately and efforts to ameliorate concerns, if any are needed, are taken care of right away. As these issues are resolved on a case-by-case as needed basis, E.L.K. relies only on a record of occurrences. This record is kept by way of work order form. While this is not a formal tracked metric in the same manner of other metrics considered and discussed in this DSP, E.L.K. does keep record of any raised Power Quality occurrences, as well as voltage service orders and electric maintenance service orders.

5.2.3.1.3(b) Historical Performance

Since August 2017, ELK has been tracking power quality momentaries at PME points throughout the system. Table 5.2-6 presents the power quality momentaries (<1min) tracked by E.L.K. along with E.L.K.'s historical performance records at various PME points.

Table 5.2-6: Power Quality Tracking at PME Points

Measure	PME	2017[1]	2018	2019	2020	2021[2]	Total	% Total
Power Quality Momentaries (<1min)	Harrow East	19	23	21	17	8	88	23
	Harrow North	3	12	16	10	7	48	13
	Belle River	0	6	6	9	3	24	6
	Kingsville	10	12	34	21	16	93	24
	Naylor	6	11	8	12	10	47	12
	Hopgood	2	13	12	9	16	52	14
	Comber North	3	3	7	6	3	22	6
	Cottam	1	2	2	3	0	8	2
	Total	44	82	106	87	63	382	100

[1] Data from August – December 2017
[2] Data from January – October 2021

Based on historical records, Kingsville and Harrow receive the most momentaries.

5.2.3.1.3(c) Performance Trend into the DSP

E.L.K. will continue to monitor complaints from customers for Power Quality issues and act to ensure the customer's needs are addressed wherever possible. E.L.K.'s limits on voltage distortion are 3% for individual voltage harmonic distortion and 5% for total harmonic distortion.

5.2.3.1.5 System Reliability

5.2.3.1.3(a) Methods and Measures

E.L.K. measures and monitors the reliability of power supply to its customers with the objective of maintaining reliability levels meeting its customers' needs. E.L.K. has aligned its reliability performance indicators and their measurement metrics with those prescribed by the OEB. Currently, two reliability performance indicators are tracked on the OEB scorecard: System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI).

SAIDI

SAIDI is an indicator of system reliability that expresses the average length of outage customers experience in the year, expressed as hours per customer per year. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the total hours of power interruptions normalized per customer served and is expressed as:

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

E.L.K.'s target value for SAIDI is 0.99. under normal operating conditions.

SAIFI

SAIFI is an indicator of the average numbers of interruptions each customer experiences, expressed as the number of interruptions per year per customer. All planned and unplanned interruptions of one minute or more are used to calculate this index. It is defined as the number of interruptions normalized per customer served and is expressed as:

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

E.L.K.'s target value for SAIFI is 0.34 under normal operating conditions.

CAIDI

The customer average interruption duration index ("CAIDI") is an indication of the speed at which power is restored after an interruption and can be found by dividing the SAIDI value for the given year by the SAIFI value:

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

Loss of Supply (LOS) outages occur due to problems associated with assets owned by another party other than E.L.K. or the bulk electricity supply system. E.L.K. tracks SAIDI and SAIFI including and excluding LOS.

"Major Events" are defined by OEB as the events beyond the control of the distributor and are unforeseeable, unpredictable; unpreventable; or unavoidable. Such events disrupt normal business operation occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers. Major Event Days (MED) are calculated using the IEEE Std 1366-2012 methodology. MEDs are confirmed by assessing whether interruption was beyond the control of E.L.K. (i.e., force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

SAIDI, SAIFI and CAIDI are measured under three scenarios:

1. By including all power interruptions
2. By excluding interruptions due to LOS
3. By excluding interruptions due to LOS and MED

5.2.3.1.3(b) Historical Performance

E.L.K.'s historical performance for SAIDI, SAIFI and CAIDI is visualized in the figures below.

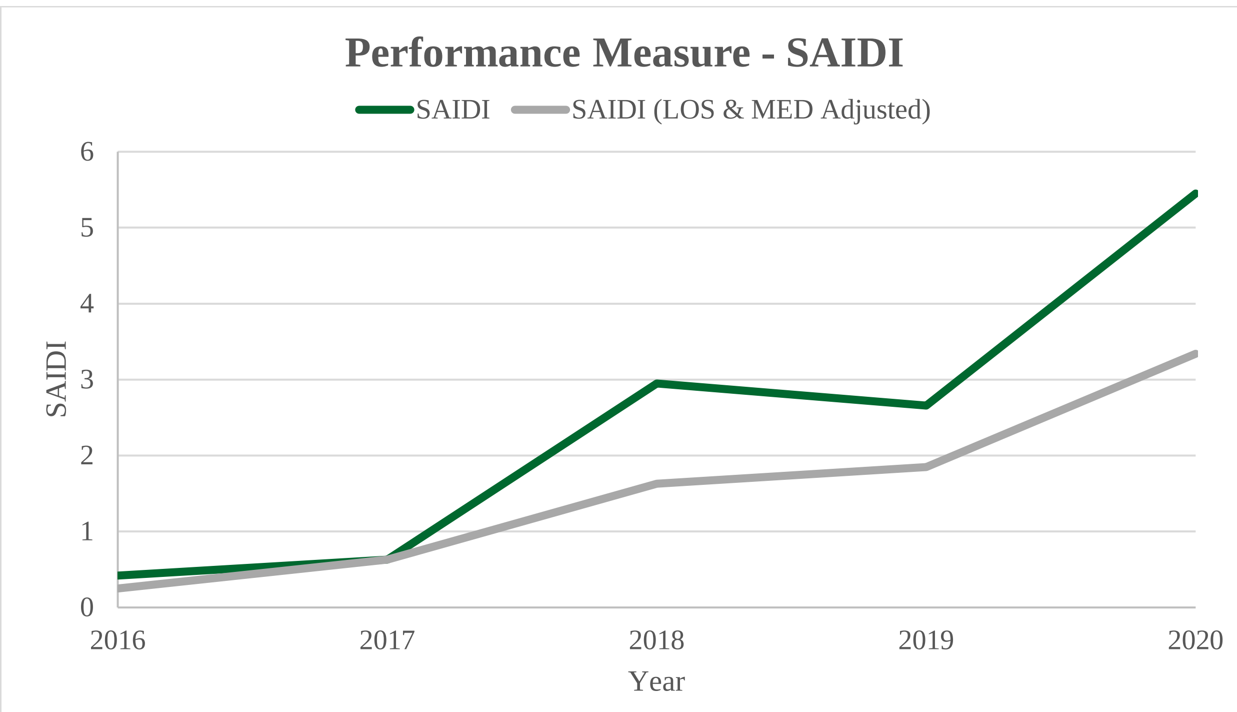


Figure 5.2-2: Performance Measure – SAIDI

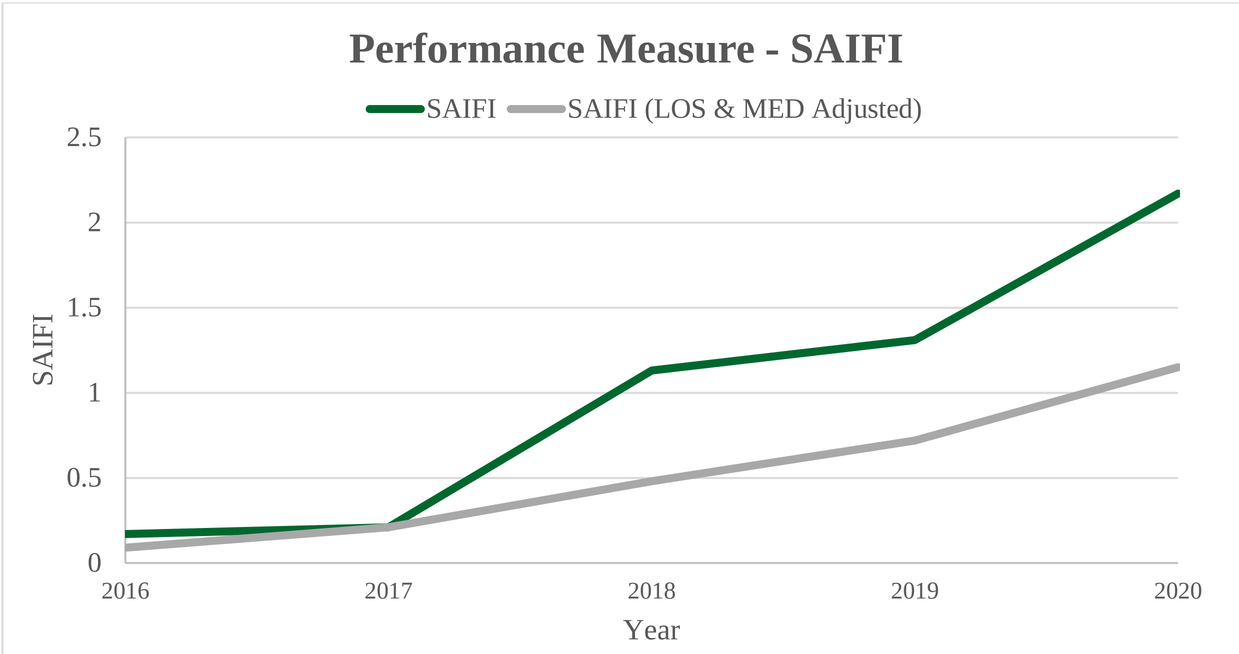


Figure 5.2-3: Performance Measure- SAIFI

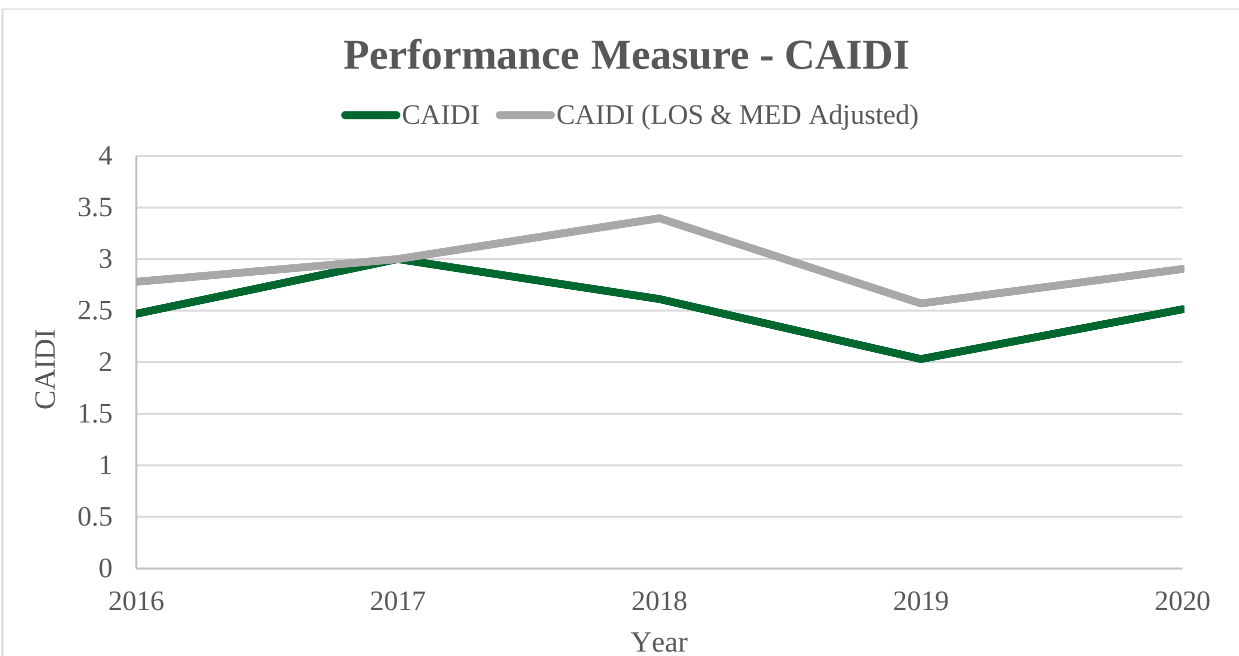


Figure 5.2-4: Performance Measure – CAIDI

E.L.K. has experienced worsening SAIDI and SAIFI trends over the historical period, with the worst performance year occurring in 2020. This is mainly due to storm events and adverse weather:

- In 2020, the targets for both SAIDI and SAIFI were exceeded. This was due to three major events: a large adverse weather event and two lightning storms in June and August of 2020.

- In 2019, the targets for both SAIDI and SAIFI were exceeded. This was due to two major events: a large adverse weather event and animal contact in July and August of 2019.

- In 2018, targets were exceeded as a result of an electricity outage in April due to a storm event.

It is important to note that in any given year, outage hours and frequency will correlate with storm occurrences and severity. E.L.K.'s reliability metric values for the historical period, adjusting for LOS and MEDs, are shown in the tables below.

Table 5.2-7: Historical Reliability Performance Metrics – All Cause Codes

Metric	2016	2017	2018	2019	2020	Average
SAIDI	0.42	0.63	2.95	2.66	5.45	2.42
SAIFI	0.17	0.21	1.13	1.31	2.17	1.00
CAIDI	2.47	3.00	2.61	2.03	2.51	2.52

Table 5.2-8: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2016	2017	2018	2019	2020	Average	E.L.K. Target
Loss of Supply Adjusted							
SAIDI	0.25	0.63	1.63	1.85	3.32	1.54	--
SAIFI	0.09	0.21	0.48	0.72	1.14	0.53	--
CAIDI	2.78	3.00	3.40	2.57	2.91	3.04	--
Loss of Supply and Major Event Days Adjusted							
SAIDI	0.25	0.63	1.63	1.85	3.34	*1.54*	*0.99*
SAIFI	0.09	0.21	0.48	0.72	1.15	*0.53*	*0.34*
CAIDI	2.78	3.00	3.40	2.57	2.90	*2.93*	--

Outage Details for Years 2016-2020

In addition to employing key reliability indicators to monitor its overall system reliability level, E.L.K. also tracks outage statistics including root causes on a regular basis. This data is collected through trouble reports. Together with key reliability indicators, these statistics provide valuable insight to the root causes for system outages and enable E.L.K. to target specific areas in an effort to lower outage frequency and reduce lengths of outages.

<u>Outages Experienced</u>

Table 5.2-7 presents the count of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business

disruption. E.L.K. continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-9: Number of Outages by cause codes - Excluding MEDs

Cause Code	2016	2017	2018	2019	2020	Total Outages	Percent Share
0-Unknown/Other	1	8	6	3	8	26	5.86%
1-Scheduled Outage	9	8	24	8	4	53	11.94%
2-Loss of Supply	1	0	7	7	11	26	5.86%
3-Tree Contacts	2	3	16	12	14	47	10.59%
4-Lightning	5	3	0	3	3	14	3.15%
5-Defective Equipment	27	28	25	43	40	163	36.71%
6-Adverse Weather	1	6	7	4	7	25	5.63%
7-Adverse Environment	1	1	1	2	1	6	1.35%
8-Human Element	1	0	1	0	0	2	0.45%
9-Foreign Interference	13	13	13	19	24	82	18.47%
Total	61	70	100	101	112	444	100%

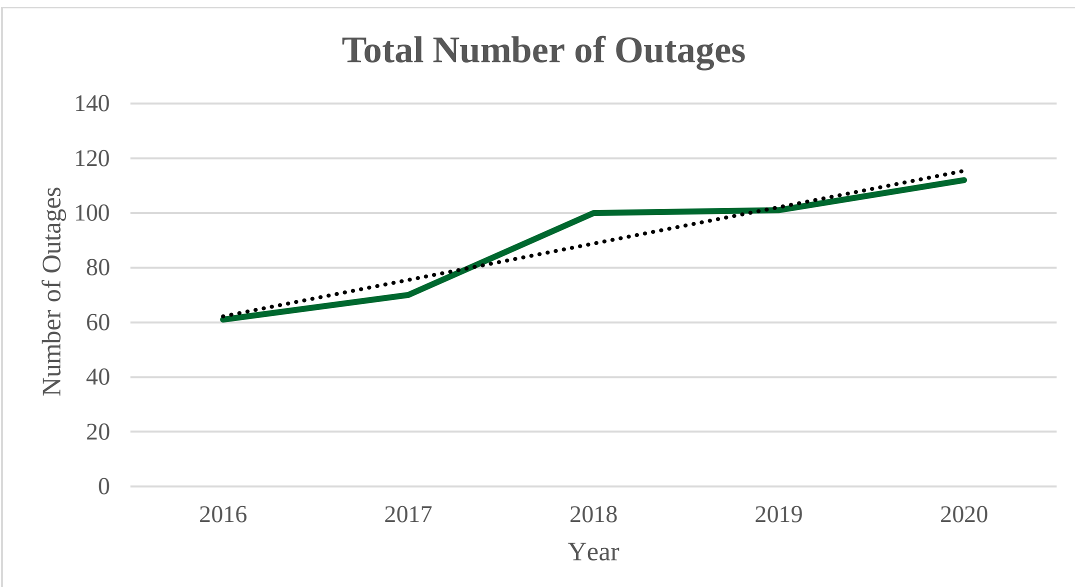


Figure 5.2-5: Total Number of Outages

The total number of interruptions over the historical period varies from a low of 61 to a high of 112, with the overall trend increasing in the period. This represents an average of 0.167 to 0.307 interruptions per day. E.L.K. is responding to customers concerns that have been communicated to them via the customer survey and publications in the media. This has resulted in a trend that indicates that improved System Renewal is required over the forecast period to allow E.L.K. to better manage the number of interruptions it has control of.

A summary of the causes of outages within E.L.K.'s system is presented in the following graph along with the percentage of overall outage incidents attributable to each cause type.

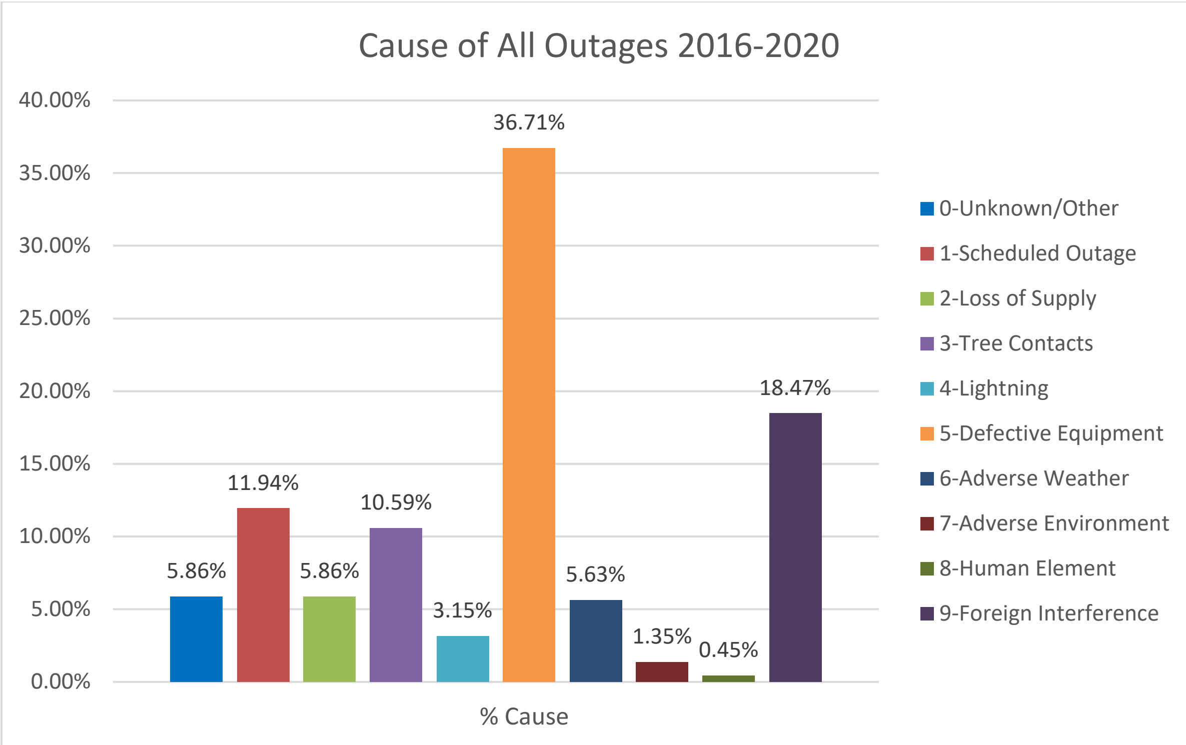


Figure 5.2-6: Cause of All Outages

Defective equipment, foreign interference, scheduled outages and tree contacts causes have been identified to be the four most common causes for outages on E.L.K.'s distribution system in over the last 5 years. Together, these causes contributed to 77.7% of the total number of outages from 2016 to 2020, excluding MEDs. Defective Equipment is the top contributing cause to the total outages experienced by E.L.K. Defective Equipment accounted for nearly 37% of the total outages experienced at E.L.K. over the historical period. These failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. E.L.K. has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. E.L.K. utilizes evaluations such as the Asset Condition Assessment and Pole Inspection Program to assist in prioritizing investments in asset classes.

Foreign Interference outages is the second top contributing cause to the total outages experienced at 18%. The outages contributing to the cause include animal interference, dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized such as educating the public about calling before digging or installing animal guards in areas observed to have a high activity of animals, both of which E.L.K. continues to do. However, other factors such as vehicle collisions can happen at random and depending on the extent and where the collision happens may result in a large impact.

At 12%, Scheduled Outages are another top contributing cause to the total outages experienced by E.L.K. These outages are due to the disconnection of service for E.L.K. to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. E.L.K. aims to plan and execute capital work and maintenance appropriately in times that would affect minimal customers and with short durations.

Tree Contacts was identified as the fourth top contributing cause to the total outages experienced by E.L.K. Over the historical period, it has contributed to nearly 11% of the total number of outages that occurred. E.L.K. is planning to improve its vegetation management program by outsourcing tree trimming to a third-party entity. Tree trimming is planned on a 4-year cycle.

<u>Customers Interrupted ("CI") and Customers Hours Interrupted ("CHI")</u>

The number of Customers Interrupted ("CI") is a measure of the extent of outages. Customer Hours Interrupted ("CHI") is a measure of outage duration and the number of customers impacted. The tables and figures below provide the historical values and trends for both CI and CHI.

Table 5.2-10: Customers Interrupted by cause codes – Excluding MEDS

Cause Code	2016	2017	2018	2019	2020	Total CI	Percent Share
0-Unknown/Other	14	494	339	270	823	1,940	3.11%
1-Scheduled Outage	79	275	383	95	40	872	1.40%
2-Loss of Supply	1,000	0	7,751	7,154	13,503	29,408	47.11%
3-Tree Contacts	16	8	217	154	1,921	2,316	3.71%
4-Lightning	141	103	0	79	2,558	2,881	4.62%
5-Defective Equipment	254	804	199	1,518	1,054	3,829	6.13%
6-Adverse Weather	10	180	538	2,962	4,882	8,572	13.73%
7-Adverse Environment	1	1	3,409	2	20	3,433	5.50%
8-Human Element	100	0	16	0	0	116	0.19%
9-Foreign Interference	403	544	655	3,661	3,794	9,057	14.51%
Total	2,018	2,409	13,507	15,895	28,595	62,424	100.00%

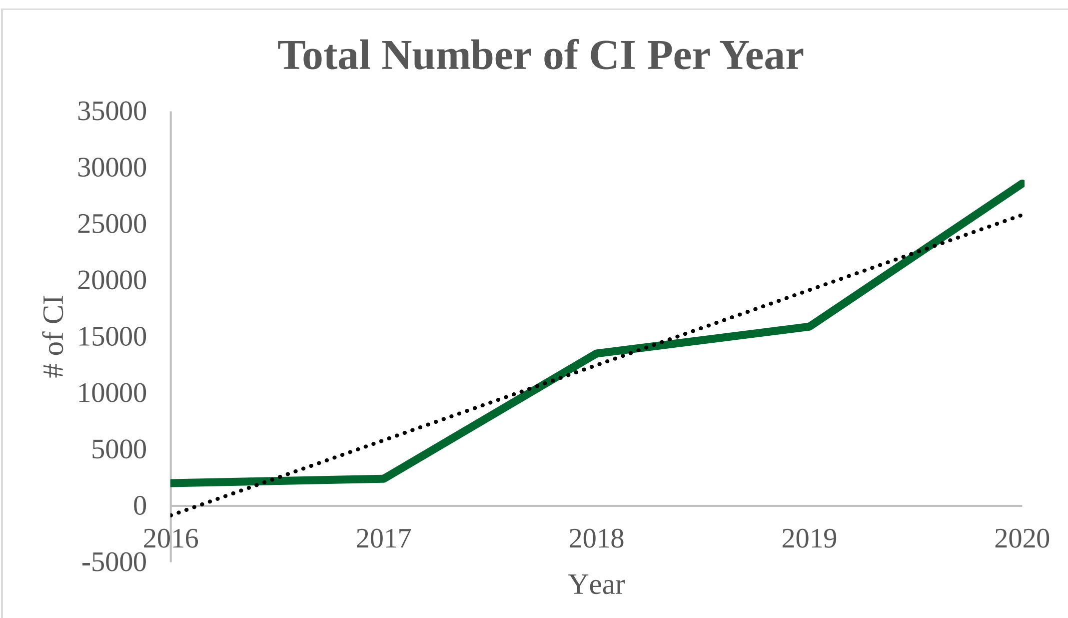


Figure 5.2-7: Total Number of Customers Interrupted by Year

Table 5.2-11: Customer Hours Interrupted by cause codes- Excluding MEDs

Cause Code	2016	2017	2018	2019	2020	Total CHI	Percent Share
0-Unknown/Other	24	832	978	477	1,180	3,491	2.30%
1-Scheduled Outage	308	455	920	161	100	1,944	1.28%
2-Loss of Supply	2,000	0	15,803	9,784	27,720	55,307	36.51%
3-Tree Contacts	17	31	441	474	5,703	6,666	4.40%
4-Lightning	257	146	0	189	7,079	7,671	5.06%
5-Defective Equipment	1,155	1,909	476	4,568	3,902	12,010	7.93%
6-Adverse Weather	13	605	2,609	6,019	18,945	28,191	18.61%
7-Adverse Environment	2	1	11,930	4	82	12,019	7.94%
8-Human Element	465	0	136	0	0	601	0.40%
9-Foreign Interference	677	3,418	1,960	10,477	7,034	23,566	15.56%
Total	4,918	7,397	35,254	32,152	71,744	151,465	100.00%

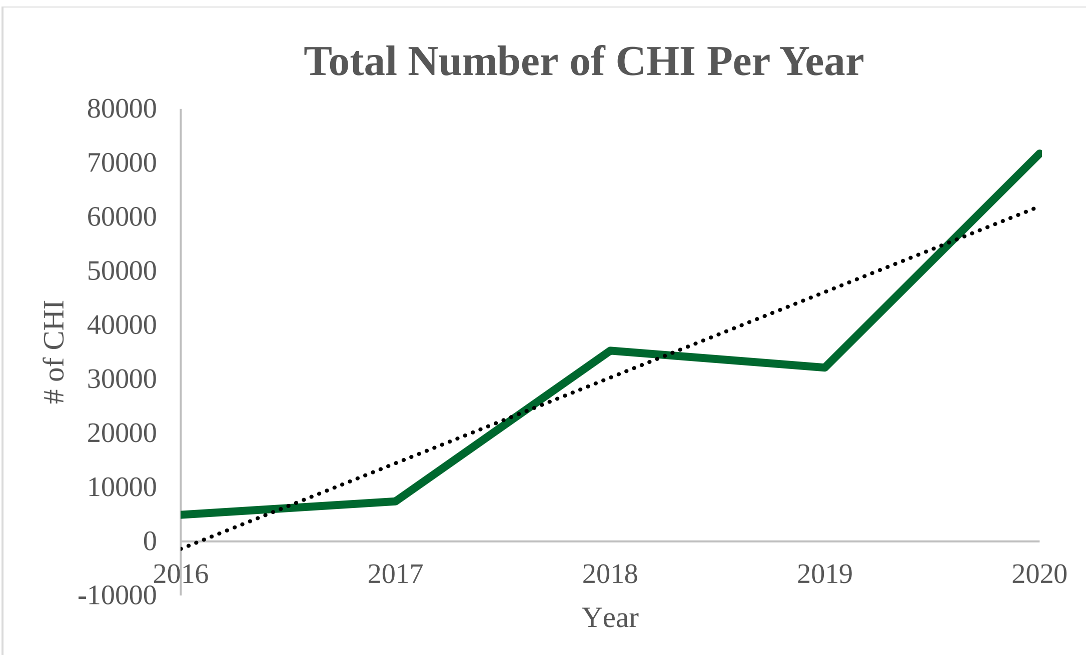


Figure 5.2-8: Total Number of Customer Hours Interrupted by Year

An increasing trend is seen for both the total customers interrupted and customer hours interrupted over the historical period. The significant increase in 2018 can be attributed to adverse weather and the increase in 2020 was significantly contributed by adverse weather and lightning.

As seen in the tables, the top cause code that can be controlled and managed by E.L.K. is *Defective Equipment.* As previously noted, E.L.K. has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage.

5.2.3.1.3(c) Performance Trend into the DSP

E.L.K. uses the SAIDI, SAIFI and CAIDI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. DSP investment priorities are expected to be in alignment with maintaining the historical average reliability performance.

Furthermore, E.L.K. uses several programs to reduce the number of controllable outages. These programs include:

- Planned renewal of end-of-life assets such as poles and transformers.
- Testing and treating of wood poles.
- Proactive vegetation management using a third-party company
- Ongoing inspection & maintenance of assets to identify and mitigate potential problems.

5.2.3.2 Cost Efficiency and Effectiveness

5.2.3.2.1 Cost Control

5.2.3.2.1(a) Methods and Measures

Managing costs is a responsibility taken seriously at E.L.K. The levels of spending are measured and prudently controlled so that customer rates are minimally affected. Total cost per customer is calculated as the sum of E.L.K.'s capital and operating and maintenance (O&M) costs divided by the total number of customers the distributor serves:

$$Total\ Cost\ per\ Customer\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Number\ of\ customer\ served}$$

E.L.K. also collects the trend data on the total cost per kilometre of line. The total cost is calculated as the sum of E.L.K.'s capital and O&M costs divided by the total kilometres of the line in service that the distributor operates to serve its customers:

$$Total\ Cost\ per\ Kilometer\ of\ Line\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Kilometers\ of\ line}$$

E.L.K. also collects the trend data on the total cost per peak system capacity. The total cost is calculated as the sum of E.L.K.'s capital and O&M costs divided by the peak MW that the distributor serves:

$$Total\ Cost\ per\ Peak\ Megawatt\ = \frac{\sum Capital\ \&\ O\&M\ costs}{Peak\ Capacity\ in\ MW}$$

Additionally, E.L.K. tracks the additional metrics introduced in OEB's newest Chapter 5 update: Total O&M per customer, Total O&M per kilometre of line and Total O&M per MW of Peak Capacity. The metrics are calculated with the total O&M costs divided by the respective number for each metric, defined as follows:

$$Total\ O\&M\ \ per\ Customer\ = \frac{\sum O\&M\ Cost}{Number\ of\ customer\ served}$$

$$Total\ O\&M\ per\ Kilometer\ of\ Line\ = \frac{\sum O\&M\ Cost}{Kilometers\ of\ line}$$

$$Total\ O\&M\ \ per\ Peak\ Megawatt\ = \frac{\sum O\&M\ Cost}{Peak\ Capacity\ in\ MW}$$

Similarly, E.L.K. tracks the Total CAPEX per customer and Total CAPEX Cost per kilometre of line. The metrics are calculated with the capital costs divided by the respective number for each metric, defined as follows:

$$Total\ CAPEX\ \ per\ Customer\ = \frac{\sum Capital\ Cost}{Number\ of\ customer\ served}$$

$$Total\ CAPEX\ per\ Kilometer\ of\ Line\ = \frac{\sum Capital\ Cost}{Kilometers\ of\ line}$$

E.L.K. has been working diligently to improve its performances, to reduce the costs, and to be more efficient. E.L.K.'s target is to maintain an Efficiency Assessment ranking of 1.

5.2.3.2.1(b) Historical Performance

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC on behalf of the OEB to produce a single efficiency ranking. The electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual and predicted costs. In 2020, for the ninth year in a row, E.L.K. was placed in Group 1, where a Group 1 distributor is considered most efficient (i.e., costs are 25% or more below predicted costs). E.L.K. was one of seven utilities in Group 1 in 2020.

E.L.K.'s historical cost performance is summarized in Table 5.2-10 and visualized in the figures below.

Table 5.2-12: Performance Measures – Cost Control

Measure	2016	2017	2018	2019	2020
Total Cost per Customer	$416	$394	$402	$418	$380
Total Cost per Kilometer of Line	$31,239	$30,987	$30,795	$31,613	$28,537
Total Cost per Peak MW	$80,486	$85,021	$76,035	$83,024	$74,072
Total O&M per Customer	$79	$74	$78	$87	$68
Total O&M per Kilometer of Line	$5,932	$5,800	$5,985	$6,581	$5,141
Total O&M per Peak MW	$15,284	$15,915	$14,777	$17,283	$13,344
Total CAPEX per Customer	$337	$320	$324	$331	$312
Total CAPEX per Kilometer of Line	$25,307	$25,187	$24,810	$25,032	$23,396

As shown in Figure 5.2-9, the Total Cost per Customer exhibits a relatively flat trend year over year contributed by the capital renewal of the asset base. E.L.K. intends to replace distribution assets proactively in a manner that balances system risks and customer rate impacts. Customer engagement initiatives continue to ensure customers have an opportunity to share their viewpoint on E.L.K.'s capital spending plans.

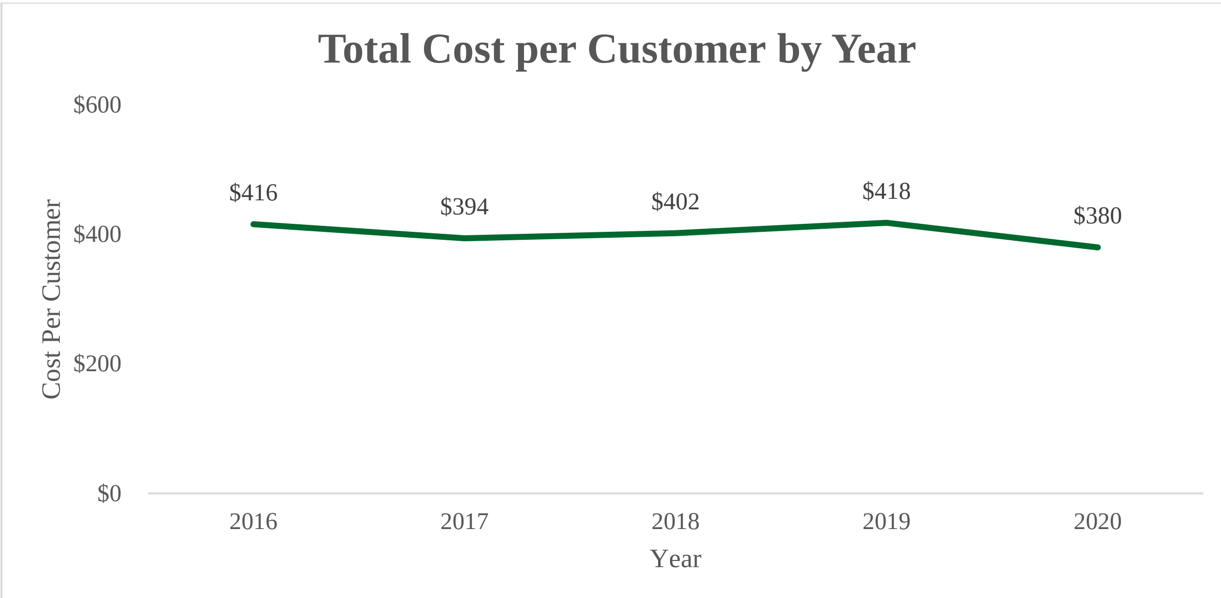


Figure 5.2-9: Performance Measure – Total Cost per Customer

The Total Cost per Kilometer metric also exhibits a fairly flat trend over the historical period. E.L.K. experiences a low level of growth in its total kilometers, and asset renewal is focused on replacing (and in some cases reducing) the same kilometers of line, not increasing the total kilometers. As a result, this trend does not vary significantly from year to year.

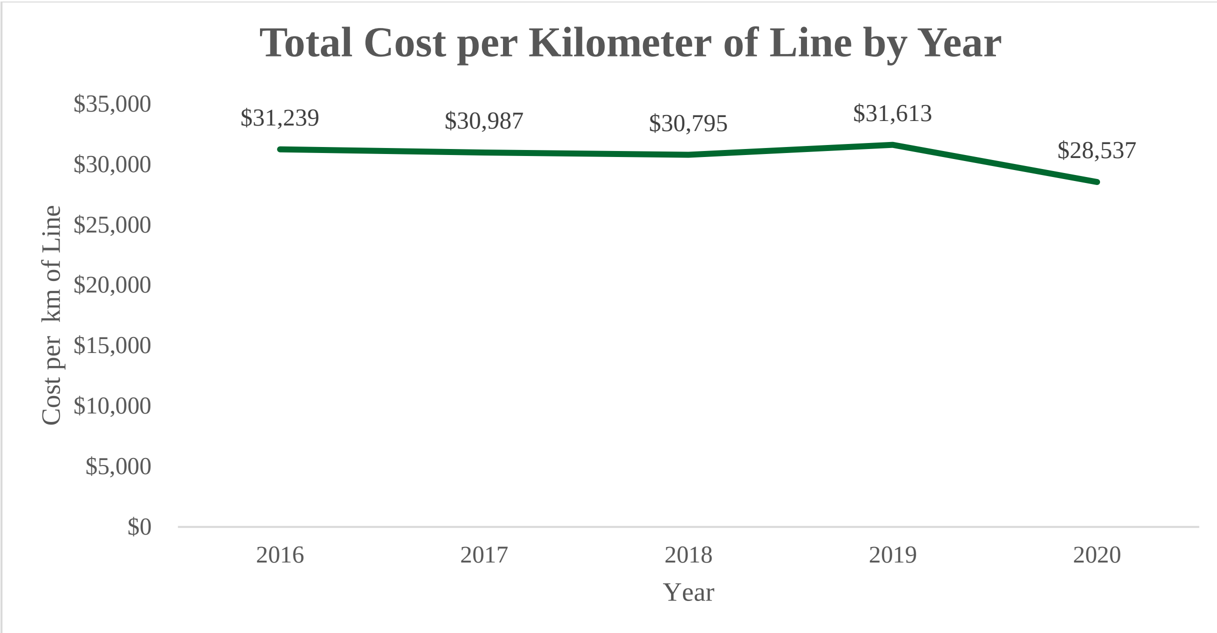


Figure 5.2-10: Performance Measure – Total Cost per Km of Line

The Total Cost per Peak MW metric also exhibits a fairly flat trend over the historical period. E.L.K. experiences a low level of growth in its peak MW capacity, with steady growth each year. As a result, this trend does not vary significantly from year to year.

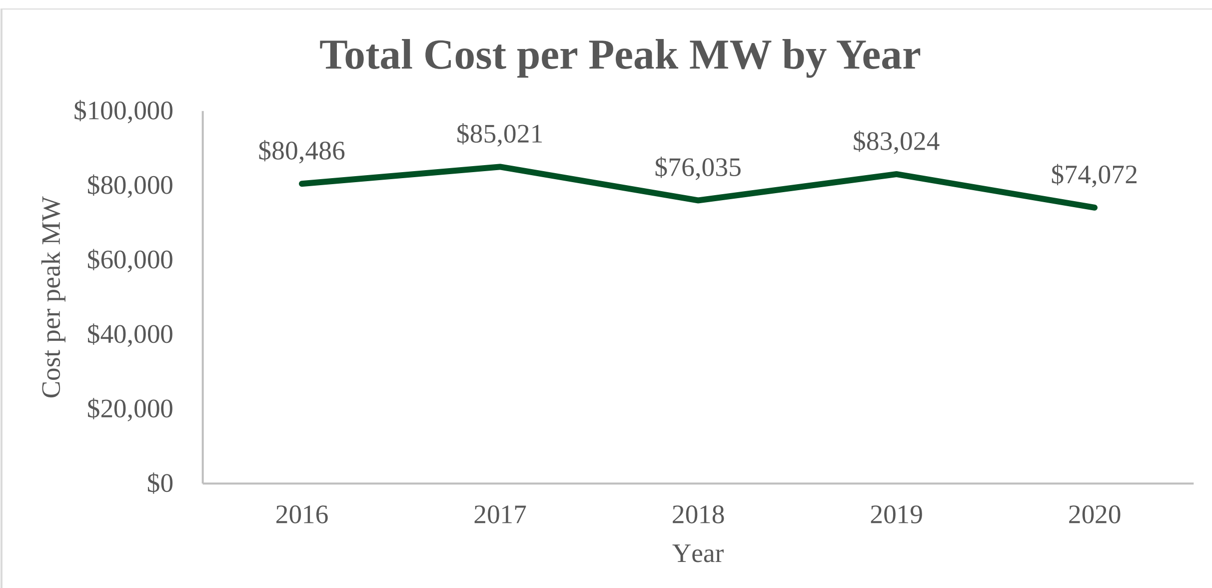


Figure 5.2-11: Total Cost per Peak MW

Operating costs are those associated with the maintenance, inspection, and operation of the system and those associated with metering, billing, and collections. A fairly flat trend can be observed from 2016 to 2018, with a slight increase in 2019 due to increased costs associated with the engagement of third-party professional services relating to its last cost of service filing, asset condition assessment and pole testing. In 2020, E.L.K. had a reduction in its O&M costs.

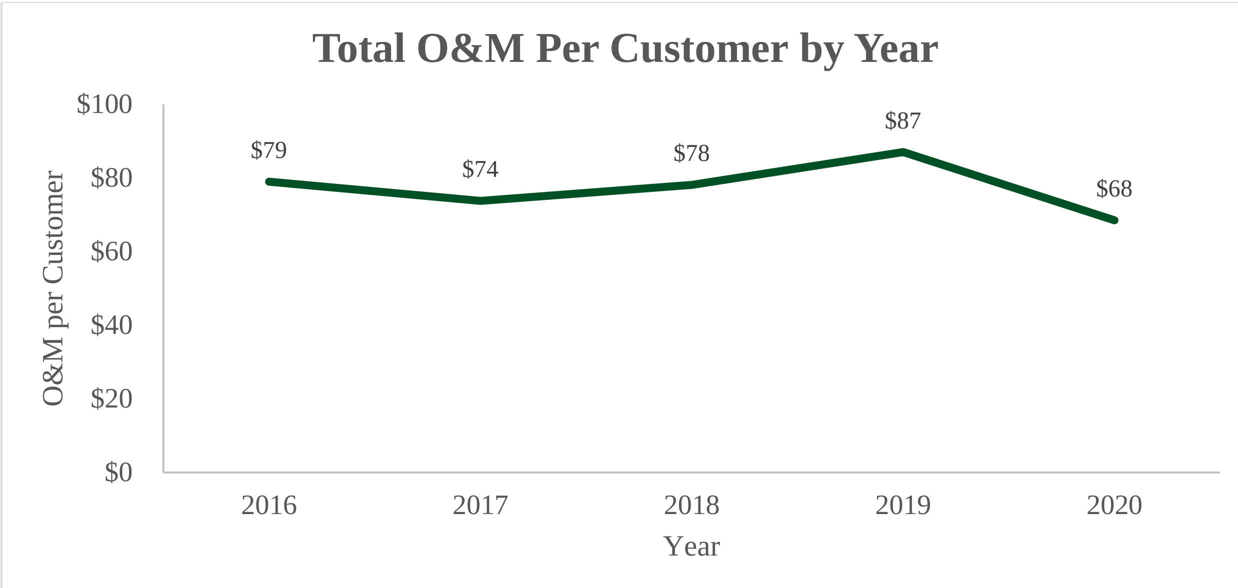


Figure 5.2-12: Performance Measure – Total O&M Per Customer

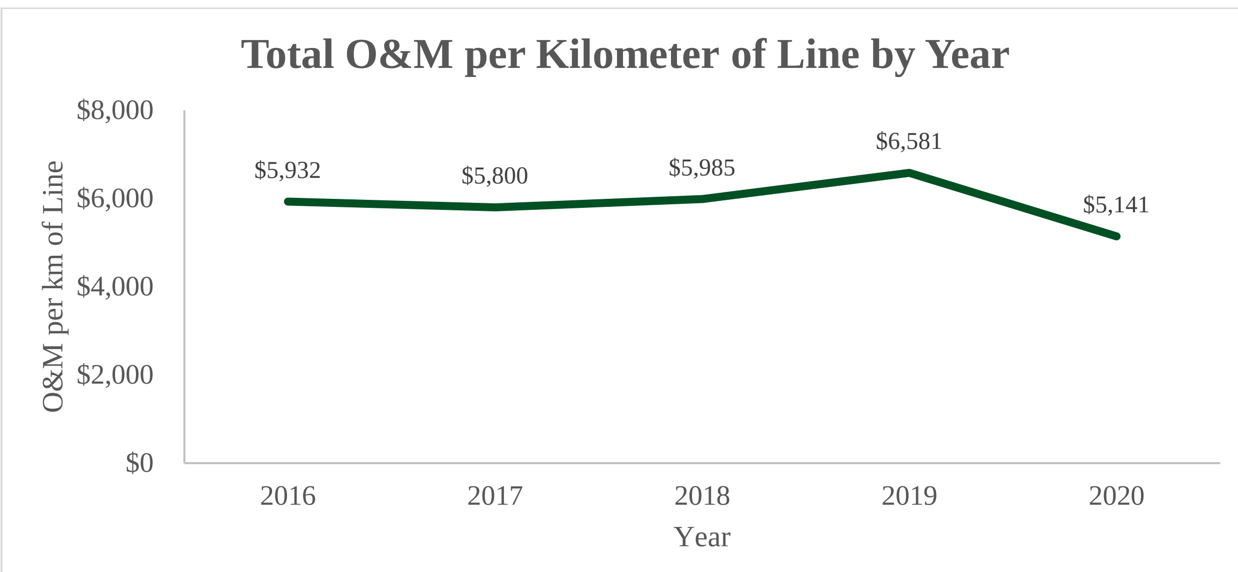


Figure 5.2-13: Total O&M Per Km of Line

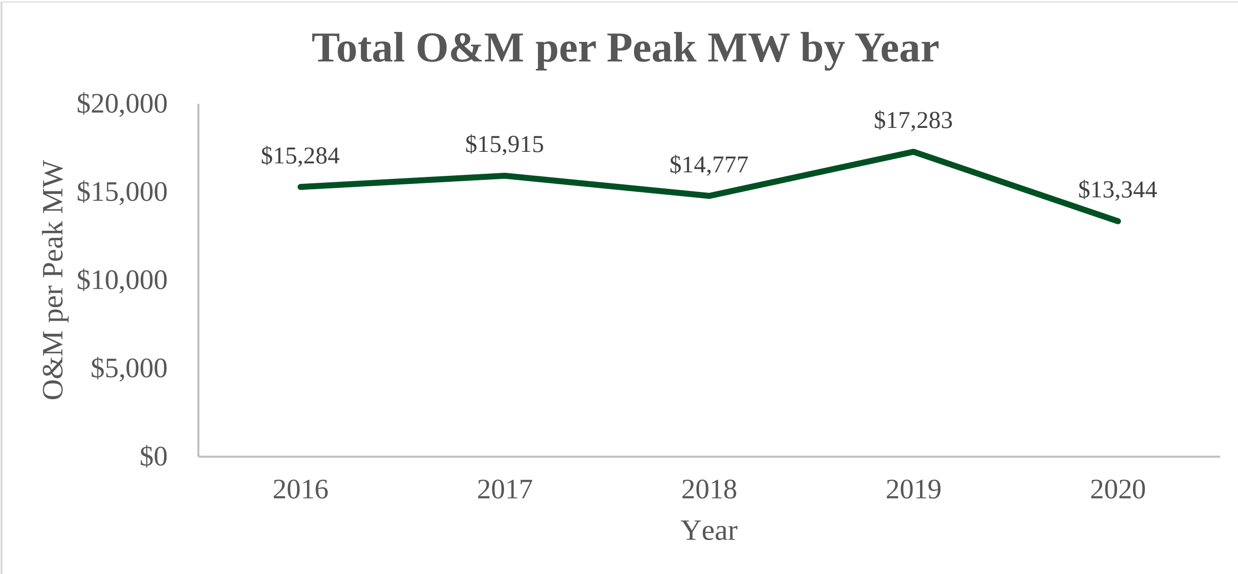


Figure 5.2-14: Total O&M per Peak Capacity

Capex costs are those associated with the capital investments required to ensure the system continues to deliver safe and reliable energy supply to E.L.K.'s customers. A fairly flat trend can be observed from 2016 to 2020. In 2020, E.L.K. had a slight reduction in its CAPEX costs.

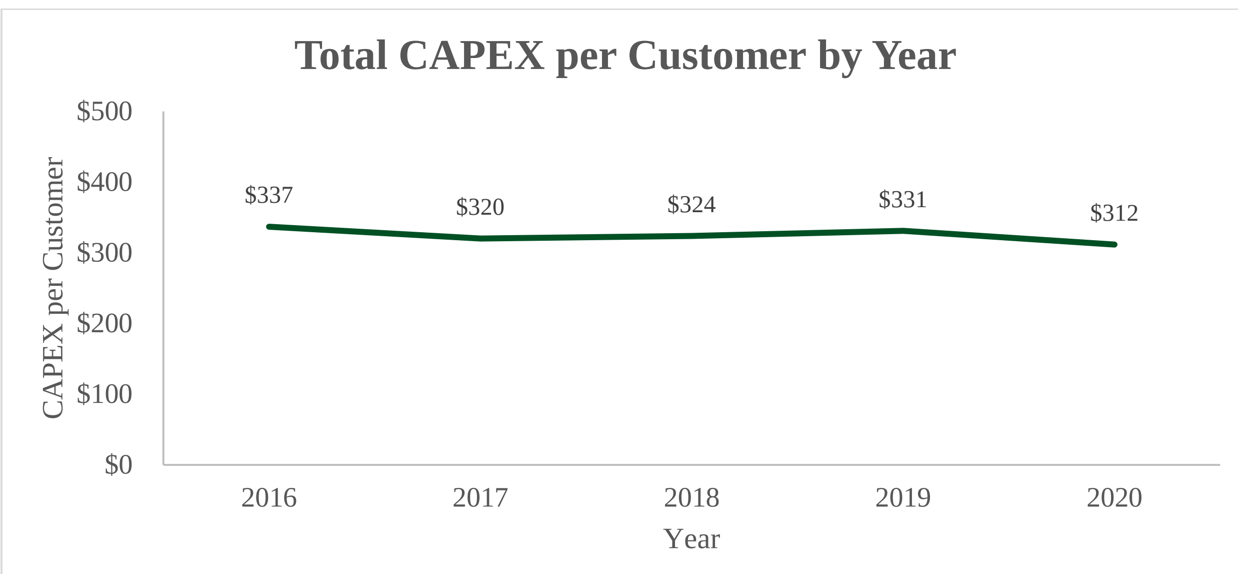


Figure 5.2-15: Total CAPEX per Customer

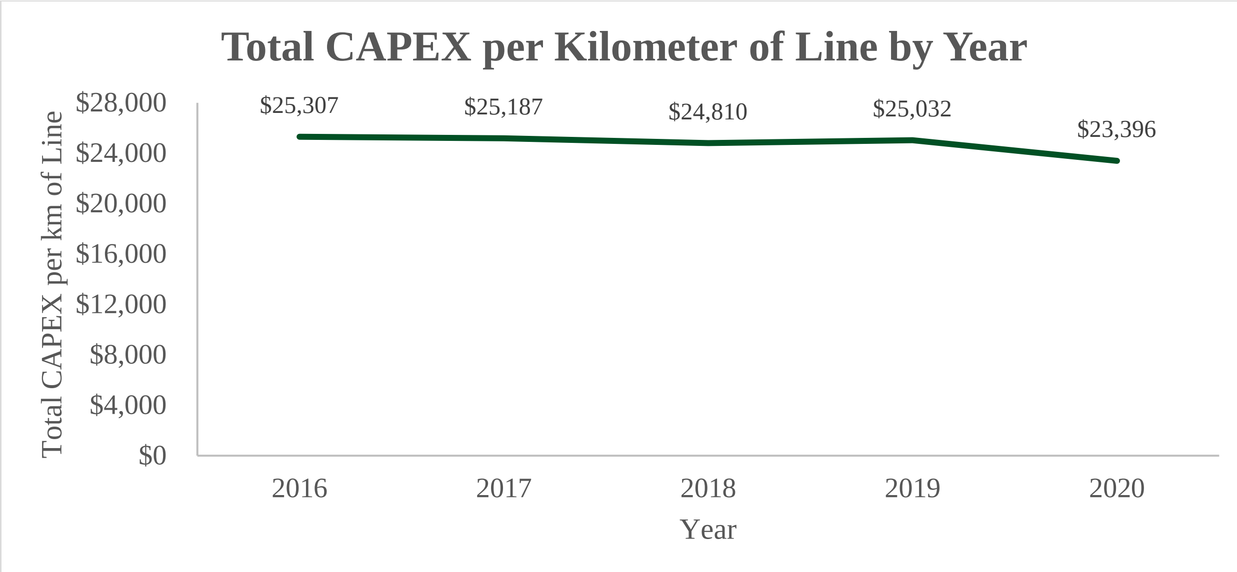


Figure 5.2-16: Total CAPEX per Kilometer of Line

5.2.3.2.1(c) Performance Trend into DSP

E.L.K. continually strives to manage costs without unduly affecting service to customers or creating significant rate increases. E.L.K. understands that the service it provides is an essential part of daily life for customers and increasing bills are a concern for all. E.L.K. will continue to seek cost savings and improve efficiency while maintaining quality customer service and effective AM as detailed in the current rate application that sets out the capital and operating investment needs of the business for the next five years. With limited growth in the E.L.K. service area, the cost metrics are expected to be in alignment with historical values over the DSP period. E.L.K. considers the projects that would have a minimal cost impact on customers but return a benefit to the quality of the service. These trade-offs are considered and communicated with customers to understand their preferences. The projects and programs considered within this DSP period take a proactive approach so that E.L.K. would be able to maintain its distribution system while minimizing the cost per customer as much as possible.

5.2.3.2.2 Asset Management

5.2.3.2.2(a) Methods and Measures

E.L.K. will be developing processes to monitor and report in the following areas:

- Physical project progress vs plan;
- Financial project progress vs. plan; and
- Actual vs. planned cost of work completed.

5.2.3.2.2(b) Historical Performance

E.L.K. has not historically tracked these metrics and will be developing processes to monitor and report in these areas going forward.

5.2.3.2.2(c) Performance Trend into DSP

E.L.K. has not historically tracked these metrics and will be developing processes to monitor and report in these areas going forward.

5.2.3.3 Asset/System Operations Performance

5.2.3.3.1 Safety

5.2.3.3.1(a) Methods and Measures

E.L.K. is committed to protecting its workforce, customers, the public and the environment. The scorecard public safety measure includes three components:

1. Public Awareness of Electrical Safety,
2. Compliance with Ontario Regulation 22/04 (O. Reg. 22/04), and
3. The Serious Electrical Incident Index.

The OEB reviewed the ESA's proposed measure and accepted the ESA's recommendations for the definitions, approach to establishing performance targets, and implementation dates for tracking and reporting related to the public safety measure.

Public Awareness of Electrical Safety

This measure 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.

O. Reg. 22/04

ESA audits of E.L.K. are conducted on an annual basis under Ontario O. Reg. 22/04. The audits are completed by the Quality Systems Assessment Registrar ("QUASAR"). QUASAR is qualified by the ESA to conduct audits under O. Reg. 22/04.

The purpose of the audit is to assess the extent of compliance of the distributor to O. Reg. 22/04, to measure whether the distributor has met the electrical requirements established for the design, construction, and maintenance of electrical distribution systems in O. Reg. 22/04.

The utility can be deemed to be in one of three performance categories:

1. In compliance
2. Needs Improvement
3. Not in compliance

E.L.K. Targets to achieve full compliance of O. Reg. 22/04, meaning zero "Non- compliance" and "Needs improvement" in future ESA audits.

Serious Electrical Incident Index

This component 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 needs for improving public electrical safety on the distribution network.

5.2.3.3.1(b) Historical Performance

E.L.K. continues to strive in maintaining its employee safety, health & wellness, and public safety measures and in compliance with O. Reg 22/04. The table below presents E.L.K.'s historical performance for each of the three components

Table 5.2-13: Performance Measure – Safety

Measure	2016	2017	2018	2019	2020	E.L.K. Target
Level of Public Awareness	78.00%	82.00%	82.00%	83.00%	83.00%	--
Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
Serious Electrical Incident Index	0	0	0	0	0	0

5.2.3.3.1(c) Effects on the DSP

E.L.K. continues to promote continued education, awareness, and application of safe work practices and as such safety continues to play a key role in project prioritization. Additionally, E.L.K. continues to demonstrate prudent compliance with O. Reg. 22/04 and as such ESA compliance continues to play a key role in project prioritization. Ensuring a safe environment for workers and the public as well as ensuring compliance is maintained has been taken into consideration in the development of the DSP and E.L.K.'s asset management and capital expenditure planning process.

5.2.3.3.2 System Losses

5.2.3.3.2(a) Methods and Measures

E.L.K.'s system losses are monitored annually. System design and operation are managed such that system losses are maintained within OEB thresholds, as defined in the OEB Practices Relating to Management of System Losses. Losses are monitored to ensure that the OEB 5% threshold is not exceeded.

$$System\ Losses = \frac{Total\ Distribution\ Losses}{Total\ kWh\ purchased}$$

5.2.3.3.2(b) Historical Performance

E.L.K. system losses over the historical period are shown in Table 5.2-12.

Table 5.2-14: Performance Measure – System Losses

Measure	2016	2017	2018	2019	2020	Target
System Losses	2.6%	5.6%	2.6%	2.3%	5.3%	<5.0%

Losses averaged 3.7% over the historical DSP period, with the recent reporting year being 5.3%. E.L.K. has generally performed well over the historical period with 2016, 2018 and 2019 all being within the OEB target. System losses in 2017 and 2020 exceeded the target primarily as a result of billing adjustments related to a number of Hydro One bills. These adjustments impacted E.L.K.'s accrued revenue and resulted in increased system losses in these years. E.L.K. expects the losses in 2021 and beyond to be more in line with the 2016, 2018 and 2019 numbers.

5.2.3.3.2(c) Effects on the DSP

System losses were exceeded in 2017 and 2020 primarily as a result of billing adjustments. This was mainly due to one customers bill. E.L.K. plans to monitor billing more closely over the forecast period in order to catch and correct any potential billing errors in order to better manage system losses within the OEB target of a maximum allowance of 5% system loss.

5.2.4 Realized Efficiencies due to Smart Metres

E.L.K. implemented its smart meter program back in 2010. E.L.K. will continue to install, reverify, and replace smart meters where appropriate to do so. By installing smart meters this allows for more accurate, and real-time data to be used. The data from these meters also minimizes the cost to E.L.K. of needing to send out personnel to manually read meters, and in turn also means customer bills will have less errors.

5.3 Asset Management Process

This section provides an overview of E.L.K.'s asset management process, a description of assets managed by E.L.K, and a presentation of E.L.K.'s asset lifecycle optimization policies and practices.

5.3.1 Asset Management Process Overview

Since issuing the 2016 DSP, E.L.K. has had a significant change in personnel and has undertaken a fundamental review and update of its asset management (AM) process. The updated AM process clearly identifies the inputs that are used at various process points. The updated AM process takes account of E.L.K.'s updated Corporate Goals. It also includes clear decision points when programs, projects, capital and operational budgets are reviewed and approved. In addition, E.L.K.'s process now includes a clear indication that the process is iterative, with latest information on asset condition, inspection and maintenance data, information from completed capital projects, and updates from third-party engagements are regularly update and inputted into the process. In addition to developing its five-year expenditure plan for this DSP, E.L.K. uses this same process to optimize and update its budget and plans each year for the following year.

Key elements of E.L.K.'s updated AM process are highlighted in the following sections along with E.L.K.'s asset management philosophy. The components of the asset management process that E.L.K. has used to prepare its capital expenditure plan are identified, including objectives, data inputs, preliminary process steps and outputs. The information generally used throughout the DSP is based on available information established at the given moment

5.3.1(a) Asset Management Objectives

One of E.L.K.'s primary goals is to provide the highest quality service to our customers by ensuring that the electrical system is designed, constructed and maintained to ensure its reliability, safety and affordability while increasing shareholder value. E.L.K. identified the following corporate goals within its 2021 Board approved Business Plan:

- Provide a safe and reliable electricity distribution system with the capacity to meet the expectations of our customers and support local economic growth.
- Promote and practise excellence in safety.
- Provide quality customer support and encourage customer feedback in order to improve customer satisfaction.
- Establish the lowest retail rates possible without compromising the financial integrity of the Corporation in compliance to our Shareholder's direction and Corporate Strategic Plan.

E.L.K.'s asset management objectives, which are aligned with E.L.K.'s corporate goals and the performance outcomes identified in the OEB's Renewed Regulatory Framework for Electricity ("RRFE"), form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain E.L.K.'s electrical distribution system. The objectives guide E.L.K. to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in and help to encourage the process of continuous improvement. The asset management objectives have been qualitatively integrated into E.L.K.'s capital investment process to prioritize investments for several years including the Test Year. Table 5.3-2 provides a ranking of prioritization of E.L.K's asset management investments.

Table 5.3-1: RRFE Outcomes - Corporate Objectives - Asset Management Linkage

RRFE Outcomes	Corporate Goals	Asset Management Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Safety	Public Safety – Minimize impacts to public safety through the consideration of the physical and geographical aspects of the project area and the assets involved. Employee Safety – Minimize impacts to employee safety through the consideration of geographical congestion, the proximity to energized equipment, the safety levels of equipment design and the complexity of the physical arrangement of assets in the project.	1. Lost/non-lost time 2. ESA Non-Compliance	1. WSIB rate class 10-year benchmarks 2. Zero (Max 1 NI)
	Reliability	Reliability and Power Quality – Minimize impacts to reliability and power quality through the analysis of the number, duration and cause of events responsible for power interruptions and maximize opportunities to reduce or eliminate future issues through design and construction practices. Operational Efficiency – Minimize factors that negatively affect operational efficiency.	1. SAIDI 2. SAIFI	1. SAIDI within range of past 5-year performance 2. SAIFI within range of past 5-year performance
Customer Focus	Customer Focus	Value for Ratepayers – Optimize asset lifecycle costs and replacement decisions to minimize the overall cost to ratepayers while maximizing benefits. Customer expectations – Ensure capital and maintenance plans align with customer service expectations.	1. Customer Survey	Customer survey results => previous year results
Financial Performance	Financial Performance	Controlling Costs - Actively manage investment planning to mitigate rate impacts while maintaining corporate financial stability and long-term sustainable performance	1. Investment Spending 2. Investment Scheduling	1. Group 1 (25% or more below predicted costs) 2. >90% annual projects completed on time
Public Policy Responsiveness	Public Policy Responsiveness	Environmental – Minimize environmental risks. Smart Grid & Renewable Generation – Facilitate smart grid development and new renewable connections.	1. Facilitation of smart grid and REG connections	1. 100% compliance when a request is made by a customer

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investments not made on time when warranted by system needs raise the risk of performance targets not being achieved and contribute to sub-optimal operation. Optimal operation of the distribution system is achieved when “right sized” investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a “just-in-time” approach. In summary, the overarching objective of the Asset Management Strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

5.3.1(b) Components of the Asset Management Process

E.L.K.’s AM process in Figure 5.3-1 demonstrates on a high-level its asset management direction, principles, and mandatory requirements. Arrows show the flow of the process and the interconnections between the various processes, inputs and outputs. The AM process interprets the company’s vision, mission, and values and serves as the connection between the top-level corporate and strategic goals and objectives through to the bottom-level asset management practices.

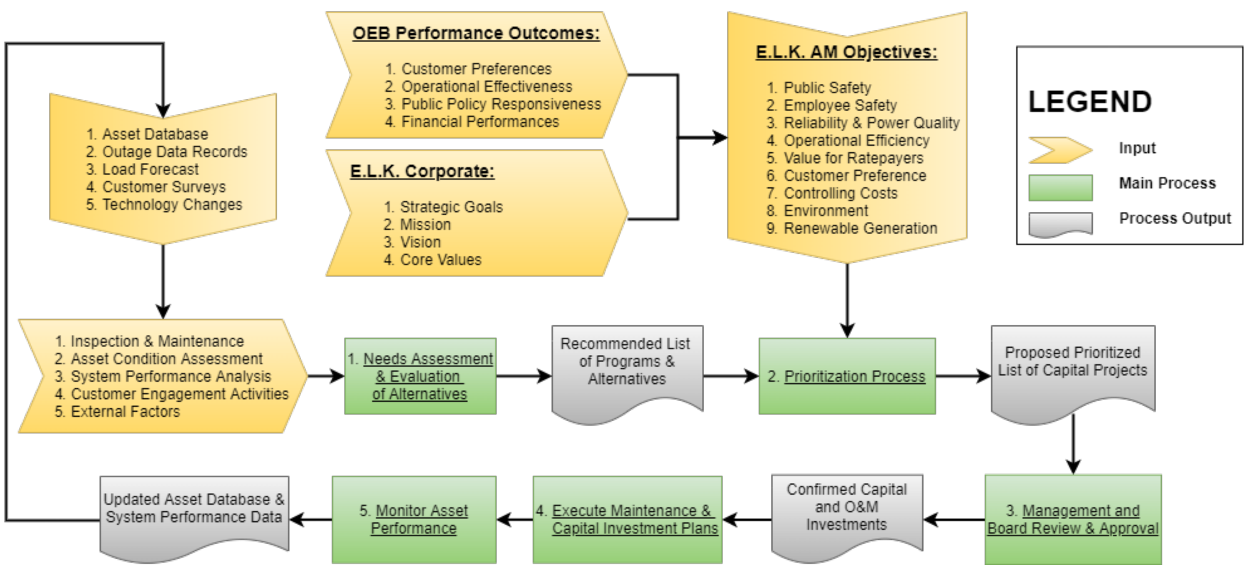


Figure 5.3-1: E.L.K. Asset Management Process

E.L.K.’s AM process is established in a way to coordinate activities to ensure the assets are optimally achieving the company’s corporate and asset management objectives. Conceptually, the process includes items such as setting out the criteria for optimizing and prioritizing asset management objectives, lifecycle management requirements of the assets, stating the approach and methods by which the assets are managed, including performance, condition and criticality assessment, the approach to the management of risk, and identifying continuous improvement initiatives. E.L.K.’s AM process is an iterative process that is regularly updated with the latest set of data and information to ensure that E.L.K. are initiating the capital projects at the right time. As well as using this process to develop its original five-year DSP capital plan, E.L.K. also use it annually to update its budget and plan for the following year.

The main components of E.L.K.'s AM process are detailed further in the following sections

5.3.1.1 Inputs

E.L.K. uses several datasets and inputs to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. This ranges from asset condition analysis, customer engagement, and inspection and maintenance results to what its AM objectives are and how they link to the OEB's performance outcomes and any external factors. Some of the key elements are explained in further detail below.

Customer Engagement

Customer requirements are reflected in the setting of performance targets, such as response times for outages and notification times for planned outages. Customer expectations are gathered via surveys and routine customer contact. E.L.K. is aware of what customers prefer through their engagement in a comprehensive customer survey.

Inspection & Maintenance

E.L.K. undertakes maintenance and inspection practices on a regular basis to maintain customer reliability and power requirements in the system. This includes inspecting assets as part of service work orders and conducting a pole maintenance and inspection program on a 3-year cycle across its 6 service territories. Inspection, maintenance, and operational data are collected and stored which is used to support E.L.K.'s operating and capital expenditure plans.

Completion of the inspection and maintenance programs is not only a matter of compliance but the results from the inspection and maintenance programs allow a continual update of the asset database. The programs allow for assets to be inspected and assessed for any necessary actions that need to be taken promptly in a proactive approach. E.L.K.'s inspection and maintenance programs are audited every year as required by Ontario Regulation 22/04.

Additional information on E.L.K.'s inspection and maintenance programs can be found in Section 5.3.3 of the DSP.

Asset Condition Assessment

An ACA and Pole Inspection Report were undertaken in 2020 to assess the condition of the system and to have empirical data on which to base the revised project prioritization. The ACA and Pole Inspection reports involves the interpretation of condition and performance data of key assets to assess the overall condition of the asset. This includes identification of assets that are in Very Poor and Poor condition, which are more closely inspected to determine the level of current risk to E.L.K. These reports are key supporting tools for developing an optimized lifecycle plan for asset sustainability. The results from these reports were incorporated into a formalized capital plan and have resulted in the revision of project prioritization within the service area for the forecast period.

E.L.K. intends to continue using the information from its ongoing proactive inspection and maintenance programs to optimize spending, with priorities considered in the scheduling. Under the proposed capital planning model, decisions to repair, refurbish or replace existing assets continues to be based on experienced judgment and knowledge of staff augmented with improved access to electronic records and structured evaluation processes.

<u>Load Growth</u>

Load forecasting and capital growth planning are key supporting tools for developing an optimized plan for meeting the expected system requirements and demand.

Given the current and forecasted load growth over the five-year planning horizon E.L.K. expects that its electrical infrastructure will continue to be able to accommodate this load growth. However, there is always the possibility of large developments, which may trigger upgrades to existing equipment or expansions to the distribution system.

<u>System Performance Analysis</u>

E.L.K. places a high level of importance on ensuring distribution system reliability meets the expectations of its customers. E.L.K. strives to continually improve its processes for collecting, measuring, analyzing, and utilizing outage information within its asset management process to effectively manage distribution system reliability in its service territories.

Outage causes are tracked and analyzed by outage cause codes. This allows E.L.K. to identify trends in causes of outages and allows for this information to feed into its prioritization and evaluation process when developing its capital investment plans. The analysis is ultimately used to inform E.L.K.'s asset management process in developing the O&M programs and capital expenditure plan for each year.

<u>External Drivers</u>

External drivers may sometimes influence E.L.K.'s decision-making in determining the optimal plans for their system. External drivers include:

- **Political** – governments have their directions and strategies that E.L.K. needs to be mindful of and to be in alignment with their plans.
- **Economic** – economic growth and decline within E.L.K.'s service area as well as the shift of business operations within residential units.
- **Social** – changes in the environment that illustrate customer needs and wants.
- **Technological** – innovation and development within the electrical/utility sector which includes automation, technology awareness, electric vehicle penetration, battery storage and new services.
- **Environmental** – ecological and environmental aspects that can affect E.L.K.'s operations or demand which includes renewable resources, weather or climate changes, and utility responsibility initiatives.
- **Regulatory/Legal** – legal allowances and/or changing requirements from the OEB as well as additional legal operations such as health and safety requirements, labour laws, and consumer protection laws.

E.L.K. continues to remain cognizant of these external drivers when developing its capital and maintenance plans.

5.3.1.2 Main Process and Process Outputs

E.L.K. uses the input data and information to enable it to determine its operating and capital expenditure plans. As illustrated in Figure 5.3-1, this is done in a multistage process with various outputs at each stage.

Firstly, using input data such as asset condition analysis, system performance, customer engagement results, a need assessment is performed. This allows E.L.K. to identify some high-level programs that E.L.K. could undertake to address the needs. As part of this, an evaluation of the different options to address the need is also performed. This includes looking at options of full replacement, refurbishments or do nothing. This allows E.L.K. to streamline the programs it will undertake with a recommended list of programs and alternatives.

Following the identification of recommended programs and alternatives to address the identified needs, a prioritization process is undertaken. At this stage, further inputs are considered, such as E.L.K.'s corporate goals, AM objectives, and the OEB performance outcomes. This information along with the programs identified are used to identify specific projects within the programs and identify a prioritized list of projects. In developing and implementing the asset management plan E.L.K.'s overarching objective is to distribute electricity safely and reliably with highest operating efficiency to maintain low distribution rates and provide the shareholders the full regulated return on equity.

The key objectives on which the asset management plan is based complete with their ranking on a scale of 5 to 1 (5 being the highest) in prioritizing investments is indicated in Table 5.3-2 below. Additional information on E.L.K.'s project prioritization process is found in Section 5.4.1.

Table 5.3-2: Prioritization Rankings

E.L.K. AM Objectives	Ranking
Public Safety	5
Employee Safety	5
Reliability & Power Quality	5
Operational Efficiency	4
Value for Ratepayers	5
Customer Preference	5
Controlling Costs	4
Environment	4
Smart Grid & Renewable Generation	3

These rankings are used to help inform a list of prioritized projects, which are then reviewed and approved by the E.L.K. management and Board. Once the projects and associated operating and capital spend has been approved, the projects are monitored from initiation to execution. Once the projects are complete the asset are monitored on their performance and updated information is fed back into the asset database.

5.3.2 Overview of Assets Managed

5.3.2(a) Description of the Service Area

E.L.K. is a local distribution company serving more than 12,611 customers in the Towns of Essex, Lakeshore and Kingsville. Within these towns, which cover a large geographic area in Southwestern Ontario, E.L.K. has six non-contiguous service areas, serving the communities of Belle River, Comber, Cottam, Essex, Harrow and Kingsville. These customers are supplied by four (4) Hydro One owned transformer stations. E.L.K.'s urban service area has a steady economic growth and covers 23 square kilometers. The service territory is shown in below:

Figure 5.3-2: E.L.K.'s Service Area

The Towns of Essex, Lakeshore and Kingsville are in southwestern Ontario, in the Essex County. The average temperature in Essex County is 9.5 °C and ranges between -28°C and 40°C. About 978 mm of precipitation falls annually with a monthly average of 78mm.

Delivery involves reducing the voltage of bulk power supply to the levels used in end-use electrical equipment. Delivery is achieved via conductors held above or below ground. E.L.K. assets include poles, overhead conductors, line transformers, switches, conduits, underground cables, IT systems, transportation equipment and office buildings. E.L.K. has seen continued growth in the number of customers in its areas, with this expected to continue for the forecast period.

5.3.2(b) Summary of System Configuration

Within the towns E.L.K. serves, which cover a large geographic area in Southwestern Ontario, E.L.K. has six non-contiguous service areas, serving the communities of Belle River, Comber, Cottam, Essex, Harrow and Kingsville. E.L.K. owns, maintains, and operates approximately 89 km of overhead primary distribution feeders and 79 km of underground primary distribution circuits including seven 27.6 kV feeders and one 8.32kV feeders. These customers are supplied by four (4) Hydro One owned transformer stations. In 2020, E.L.K. delivered approximately 128,000,000 kWh of total billed energy. Responsibility for maintaining circuits lies with the respective owners of the equipment.

The basic configuration is shown in Figure 5.3-3 below.

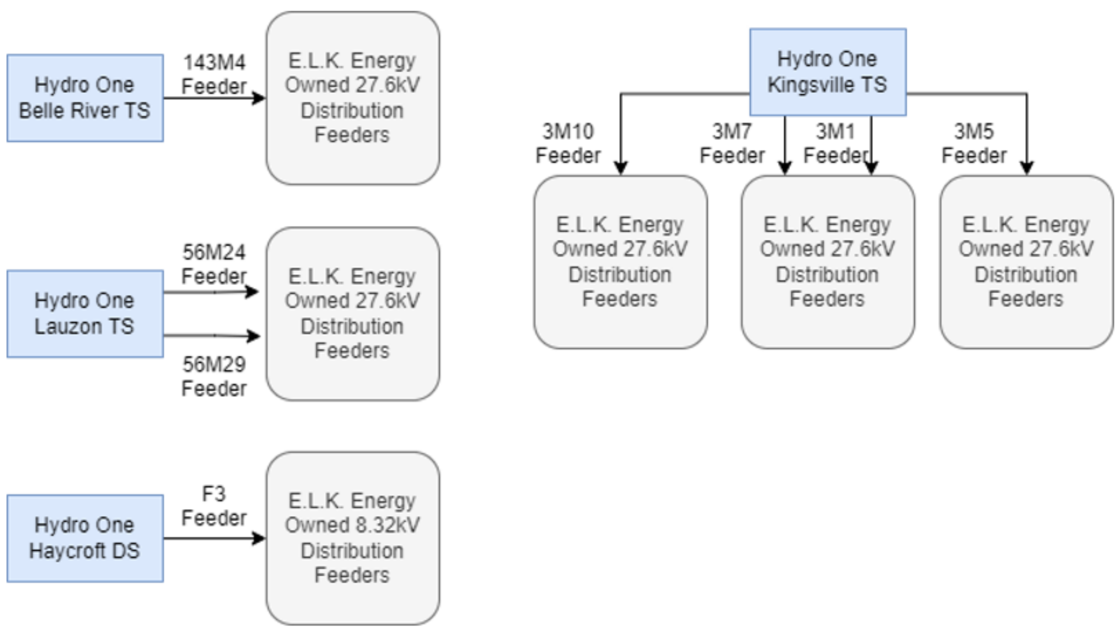


Figure 5.3-3: E.L.K.'s System Configuration

Table 5.3-3 below shows the Hydro One Stations that supply E.L.K.'s feeders, the voltage, capacity and the peak load.

Table 5.3-3: Hydro One Stations

Station	Feeder	Voltage (kV)	Peak Load (kW)	Generation Capacity (kW)
Belle River TS	M4	27.6	8624	8376
Haycroft DS	F3	8.13	1779	1101
Kingsville TS	M1	27.6	15354	1646
Kingsville TS	M5	27.6	16768	232
Kingsville TS	M7	27.6	10201	6799
Kingsville TS	M10	27.6	8902	8098
Lauzon TS	M24	27.6	16541	459
Lauzon TS	M29	27.6	13401	3599

5.3.2(c) Results of Asset Condition Assessment

E.L.K. engaged Kinectrics Inc (Kinectrics) in 2020 to perform an Asset Condition Assessment (ACA) on selected distribution assets. An assessment produces a quantifiable evaluation of asset condition and also aids in prioritizing and allocating sustainment investments. This undertaking, if done continuously over time, allows utilities to monitor trends in the condition of its assets and to continuously improve its assessment process and asset management practices. This assessment covered ’s asset population as of December 2019.

The categories and sub-categories of assets considered in the ACA study are as follows:

- Pole Mounted Transformers
- Pad Mounted Transformers
- Overhead Switches
- Pad Mounted Switchgear
- Underground Cables

For each asset category, available data were assessed, and a Health Index distribution was determined. A summary of the Health Index evaluation results is shown in

Table 5.3-4: Health Index Evaluation Summary

Asset Category		Population	Sample Size	Average Health Index	Health Index Distribution					Average Age	Average DAI	Age Availability
					Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)			
Pole Mounted Transformers		851	628	87%	6	19	37	120	446	33	Age Only	74%
Pad Mounted Transformers		818	668	85%	40	54	55	45	474	25	Age Only	82%
Overhead Switches		11	11	98%	0	0	0	0	11	29	Age Only	100%
Pad Mounted Switchgear		2	2	77%	0	0	1	0	1	19	Age Only	100%
Underground Cables (km)		124.4	113.1	99.6%	0.0	0.0	0.0	1.4	111.7	19	Age Only	91%

0% 100%

Age Only No information other than age

For each asset category the population, sample size (number of assets with age available), average age, age availability and average DAI are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure 5.3-4. Note that the Health Index distribution percentages are extrapolated from the asset group's sample size.

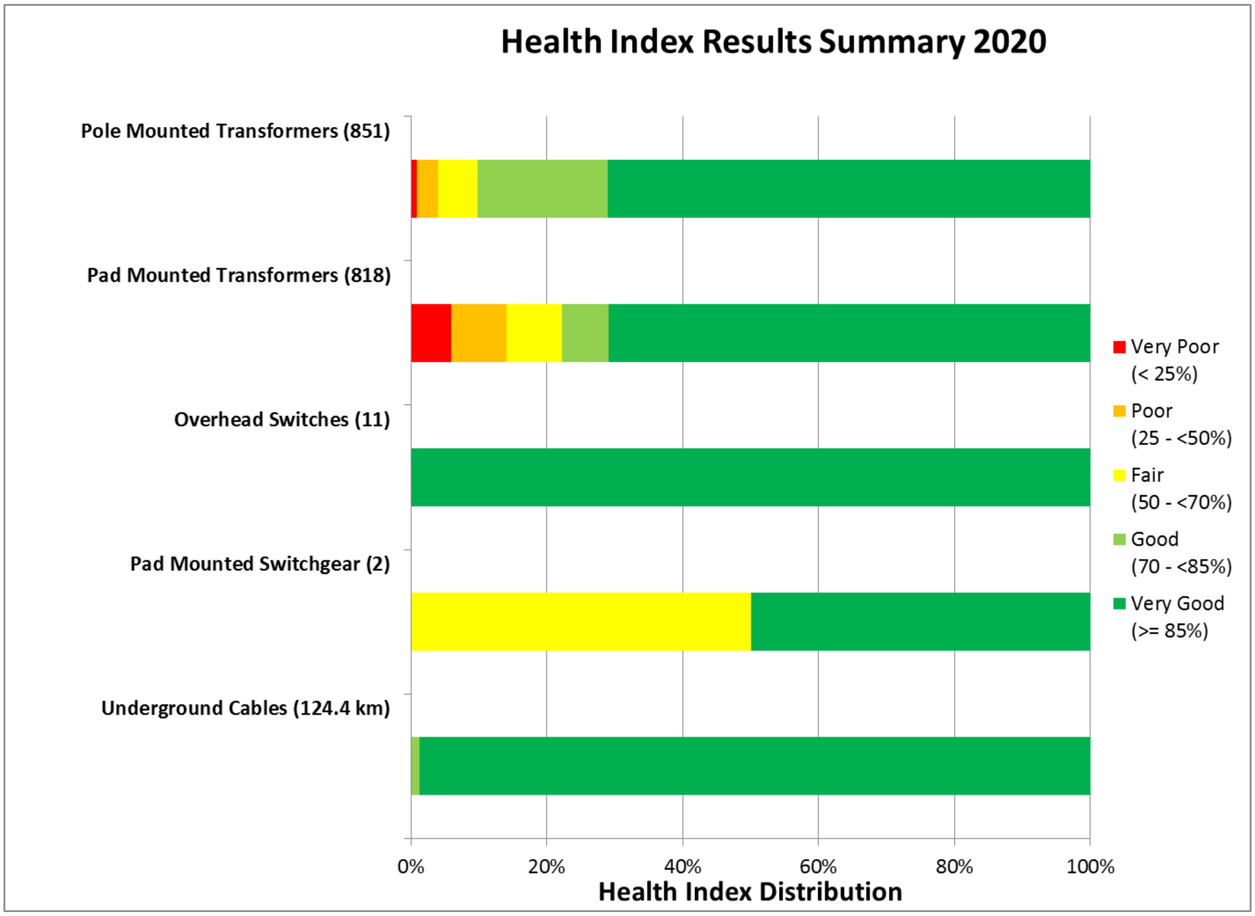


Figure 5.3-4: 2020 Health Index Results

It can be observed that out of the 5 categories, 3 of them had over 80% of their units classified as "good" or "very good", and all these 3 groups had an average Health Index score of greater than 80%. The ACA report is found in Appendix A which contains detailed results for each asset class.

Pole Mounted Transformers

E.L.K. owns 851 pole mounted transformers within its service territory. The installation date is known for 628 of the 851 pole mounted transformers. The average age of the units was 33 years. The distribution for age of pole mounted transformers can be seen in Figure 5.3-5.

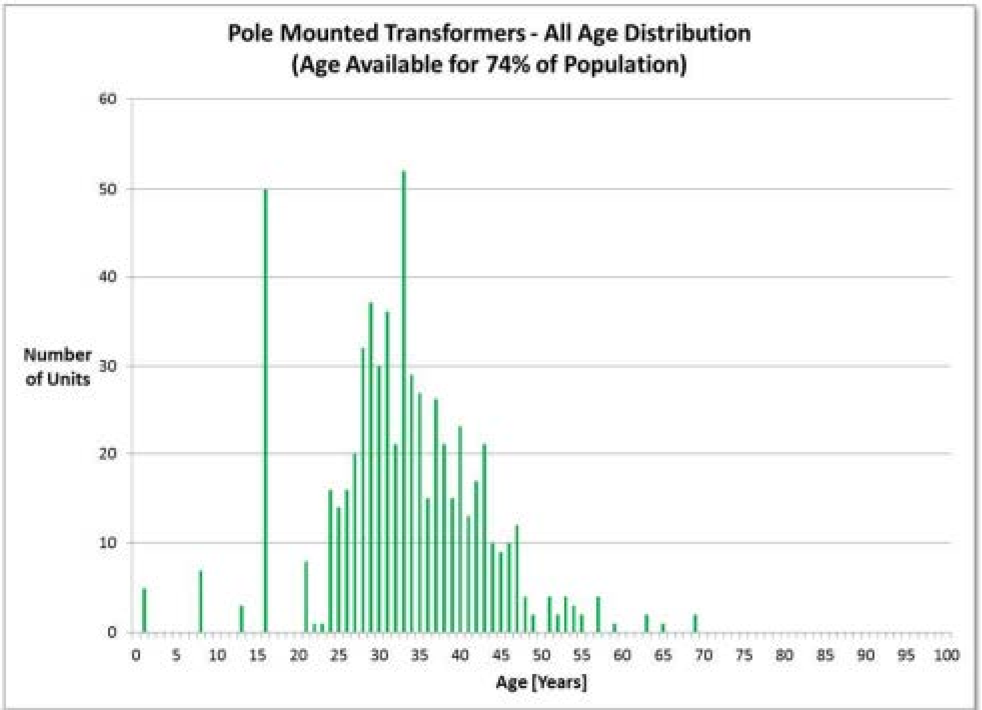


Figure 5.3-5: Pole Mounted Transformer Age Demographic

E.L.K.'s installation date and the cumulative likelihood of survival at a given age for pole mounted transformers was used to calculate the HI. The overall extrapolated HI distribution for pole mounted transformers is presented in Figure 5.3-6. Most of the pole mounted transformers are either in Very Good or Good condition with around 10% of the population being in either Fair, Poor, or Very Poor condition. The average Health Index score was 87% for pole mounted transformers.

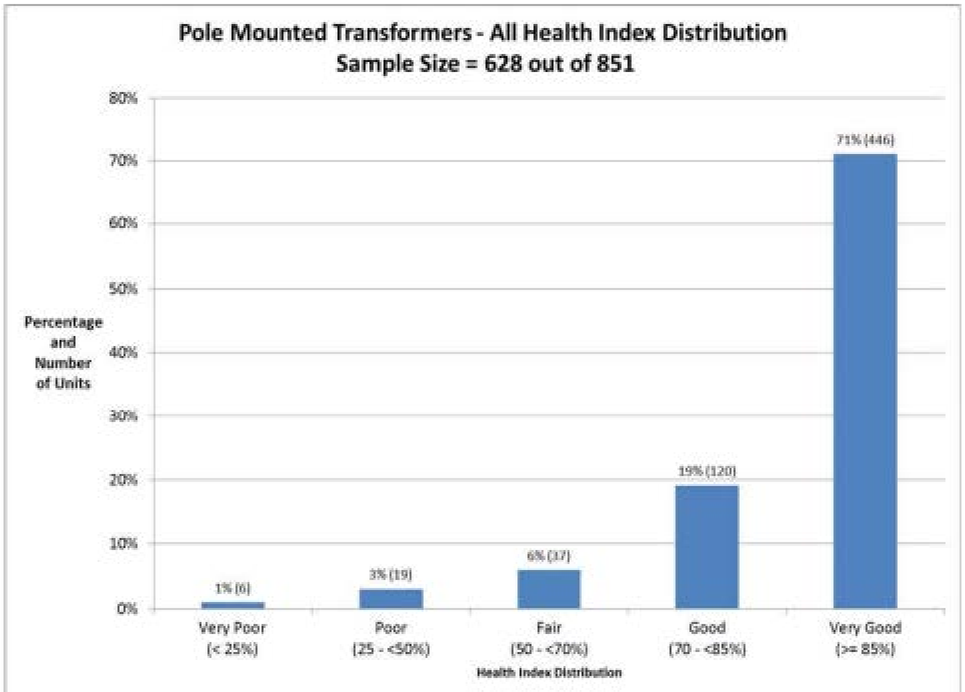


Figure 5.3-6: Pole Mounted Transformer HI Results

Pad Mounted Transformers

E.L.K. owns 818 pole mounted transformers within its service territory. The installation date is known for 668 of the 818 pad mounted transformers. The average age of the units was 25 years. The distribution for age of pad mounted transformers can be seen in Figure 5.3-7.

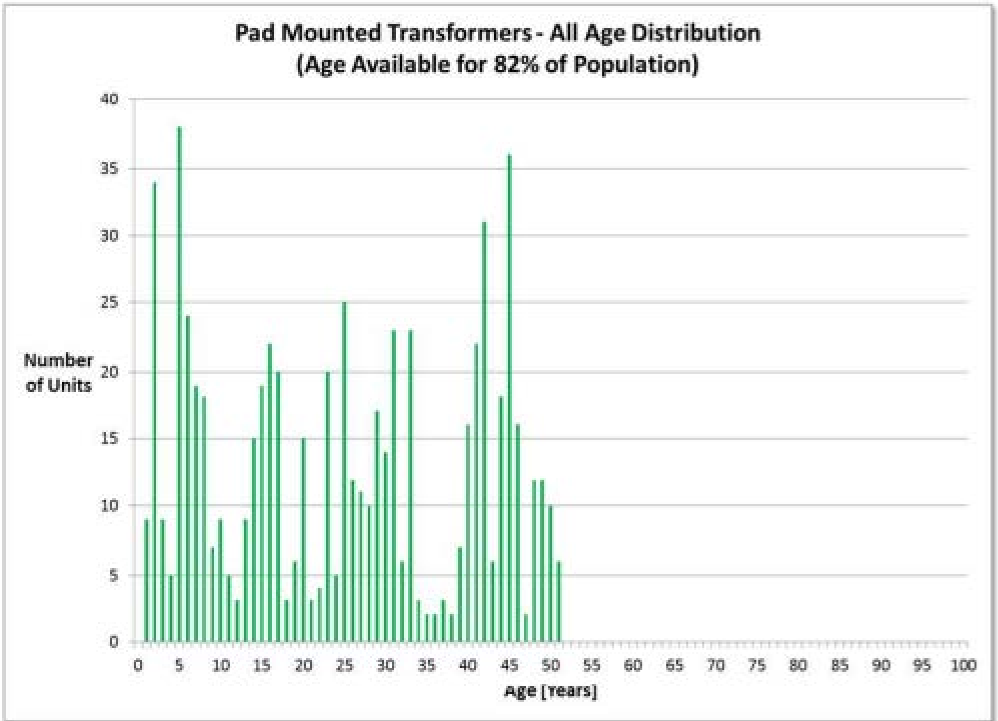


Figure 5.3-7: Pad Mounted Transformer Age Demographic

E.L.K.'s installation date and the cumulative likelihood of survival at a given age for pad mounted transformers was used to calculate the HI. The overall extrapolated HI distribution for pad mounted transformers is presented in Figure 5.3-8. Most of the pad mounted transformers are in Very Good with around 29% of the population being in either Good, Fair, Poor, or Very Poor condition. The average Health Index score for this asset group was 85% for pad mounted transformers.

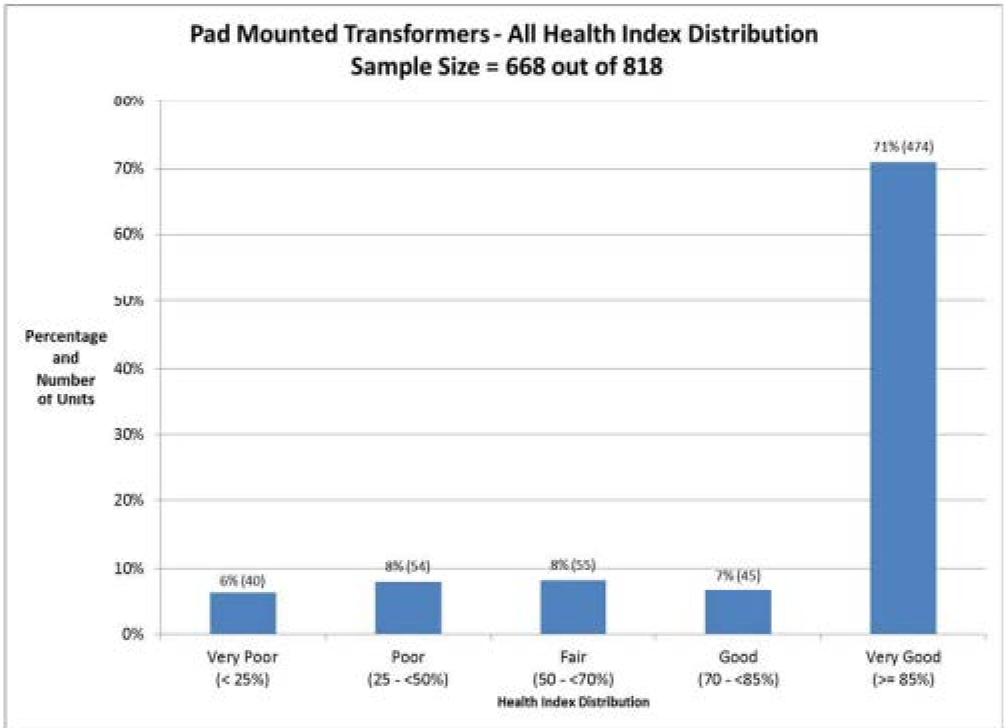


Figure 5.3-8: Pad Mount Transformer HI Results

Overhead Line Switches

E.L.K. owns 11 overhead line switches within its service territory. The installation date is known for 11 of the 11 overhead line switches. The average age of the units was 29 years. The distribution for age of overhead line switches can be seen in Figure 5.3-9.

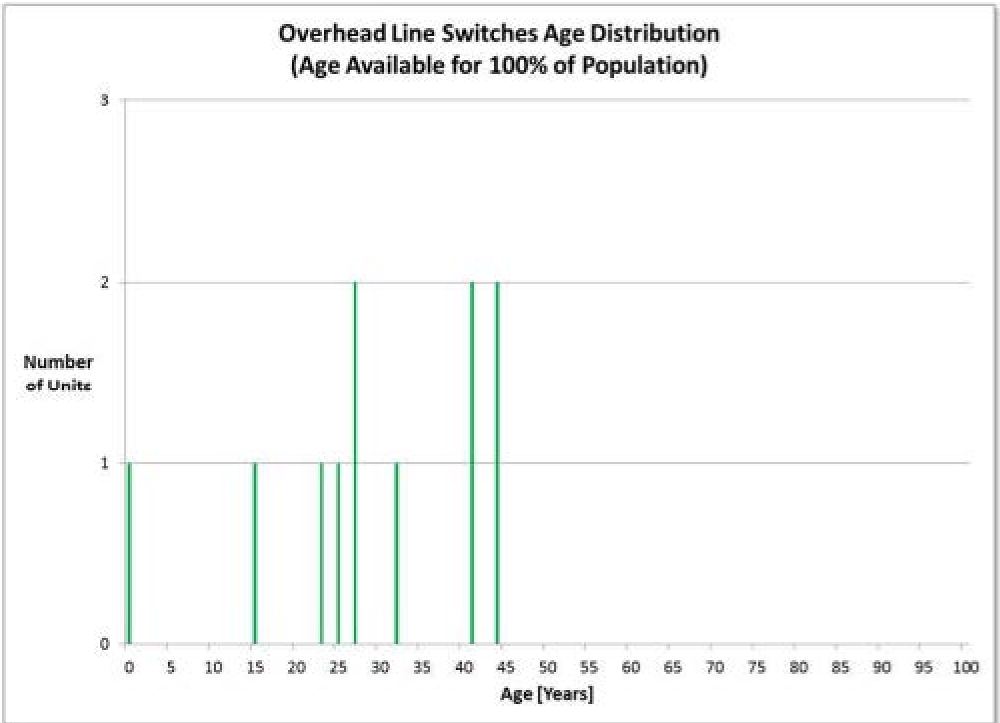


Figure 5.3-9: Overhead Line Age Demographic

E.L.K.'s installation date and the cumulative likelihood of survival at a given age for overhead line switches was used to calculate the HI. The overall extrapolated HI distribution for overhead line switches is presented in Figure 5.3-10. All the overhead line switches are in Very Good condition. The average Health Index score for this asset group was 100% for overhead line switches.

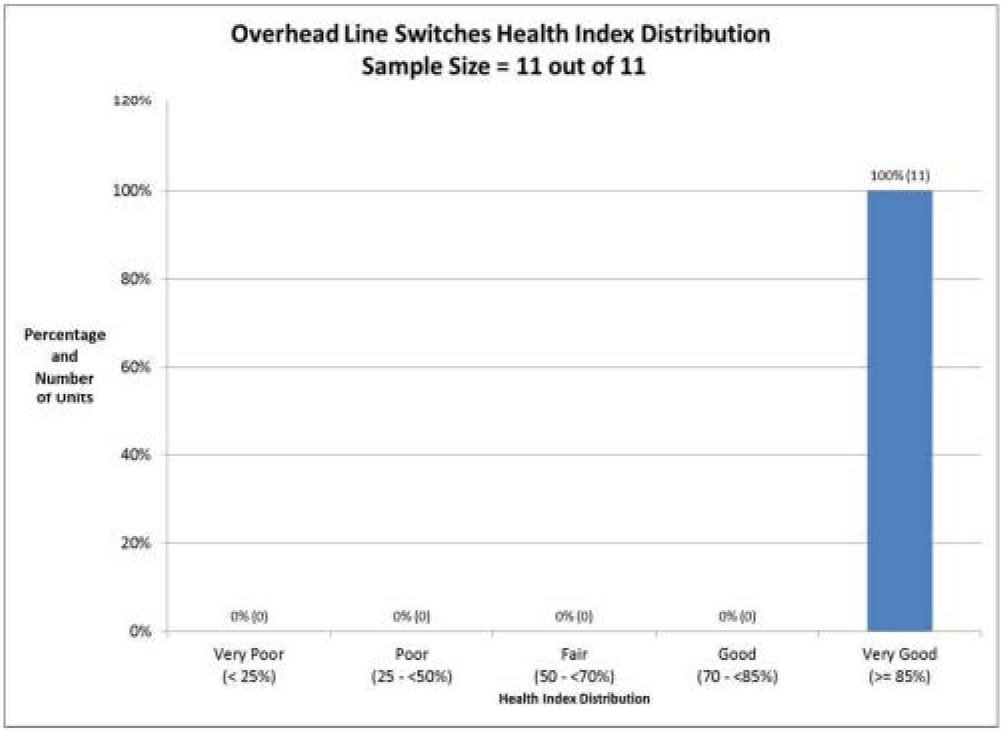


Figure 5.3-10: Overhead Line HI Results

Pad Mounted Switchgears

E.L.K. owns 2 pad mounted switchgears within its service territory. The installation date is known for 2 of the 2 pad mounted switchgears. The average age of the units was 19 years. The distribution for age of pad mounted switchgears can be seen in Figure 5.3-11.

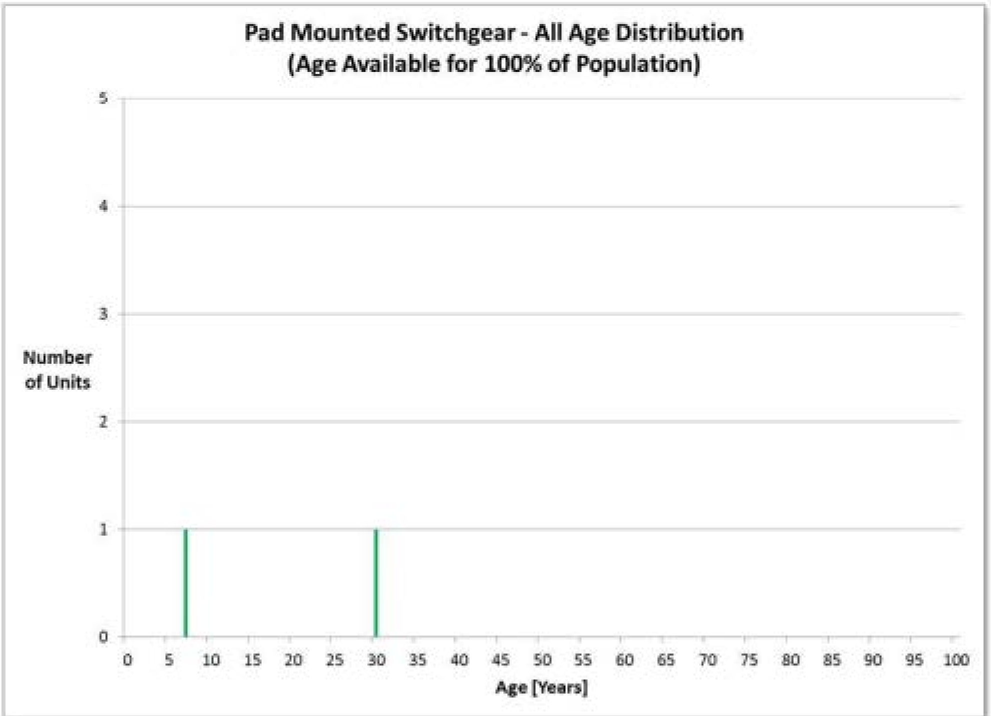


Figure 5.3-11: Pad Mounted Switchgear Age Demographic

E.L.K.'s installation date and the cumulative likelihood of survival at a given age for pad mounted switchgears was used to calculate the HI. The overall extrapolated HI distribution for pad mounted switchgears is presented in Figure 5.3-12. All of the pad mounted switchgears are either in Very Good or Fair condition. The average Health Index score for this asset group was 77% for pad mounted switchgear.

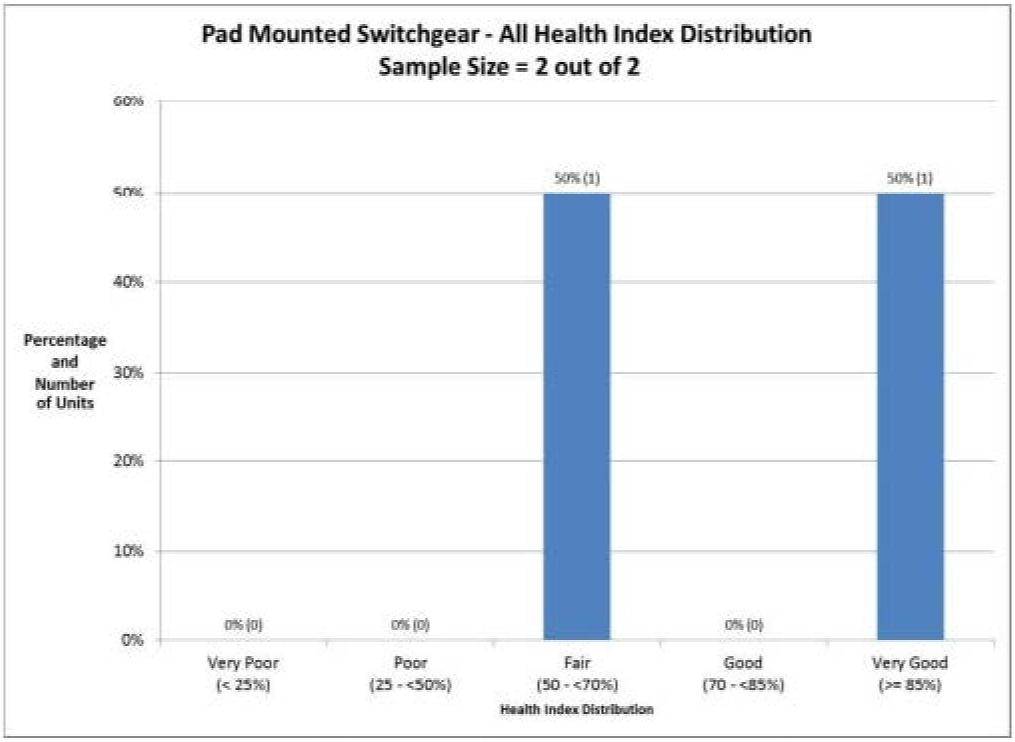


Figure 5.3-12: Pad Mounted Switchgear HI Results

Underground Cables

E.L.K. owns 124.4 conductor-km of underground cables within its service territory. The installation date is known for 113.1 conductor-km of 124.4 conductor-km underground cables. The average age of the units was 19 years. The distribution for age of underground cables can be seen in Figure 5.3-13.

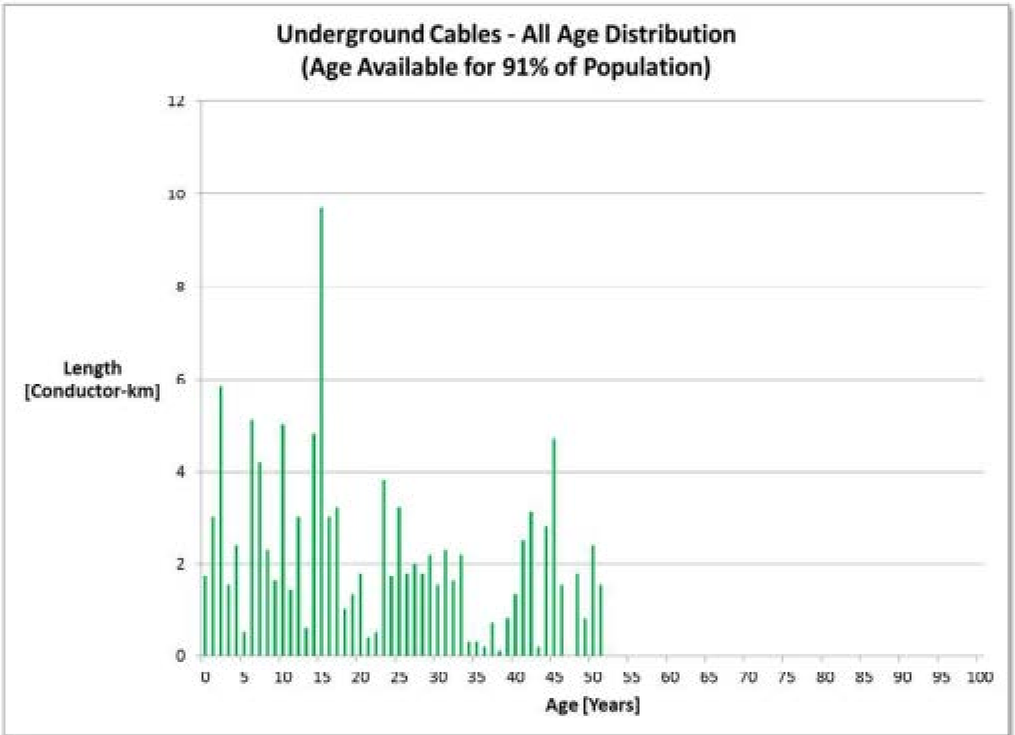


Figure 5.3-13: Underground Cable Age Demographic

E.L.K.'s installation date and the cumulative likelihood of survival at a given age for underground cables was used to calculate the HI. The overall extrapolated HI distribution for underground cables is presented in Figure 5.3-14. Majority of the underground cables are in Very Good with 1% in Good condition. The average Health Index score for this asset group was 99.6% for underground cables.

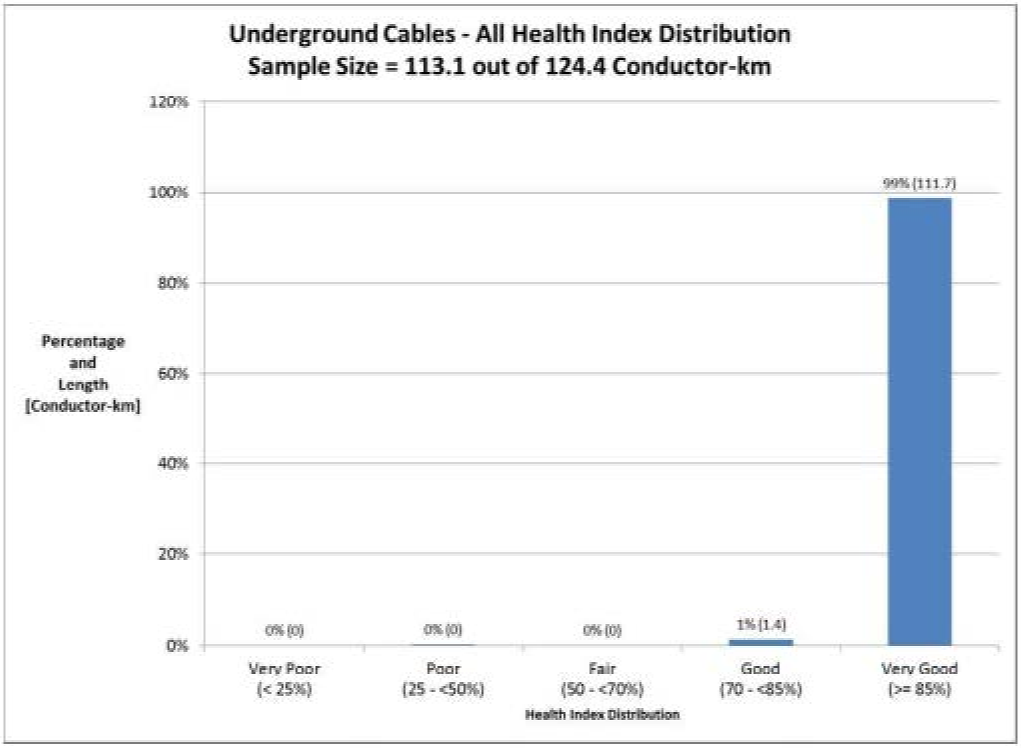


Figure 5.3-14: Underground Cable HI Results

Along with the ACA, E.L.K. is developing a condition-based flagged for action plan for each of its asset groups. The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 10 years. The numbers of units are estimated using either a proactive or reactive approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year. Both approaches consider asset removal rate and probability of failure. Table 5.3-5 shows the Year 0 (year 2021) and 10 Year cumulative Flagged for Action Plan. Table 5.3-6 shows the 10 Year Flagged for Action Plan annually.

Table 5.3-5: Overall Asset Replacement Action Plan

Asset Category		1st Year Action		10 Year Action in Total		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
Pole Mounted Transformers		16	1.9%	194	22.8%	Reactive
Pad Mounted Transformers		48	5.9%	269	32.9%	Reactive
Overhead Switches		0	0.0%	0	0.0%	Reactive
Pad Mounted Switchgear		0	0.0%	0	0.0%	Reactive
Underground Cables (km) (km)		0	0.0%	2.1	1.7%	Reactive

100% 0%

Table 5.3-6: Annual Asset Replacement Action Plan

Asset Category		Flagged for Action Plan by Year										
		0	1	2	3	4	5	6	7	8	9	10
Pole Mounted Transformers		16	16	18	18	20	20	20	21	22	23	23
Pad Mounted Transformers		48	42	36	30	26	22	20	17	15	13	12
Overhead Switches		0	0	0	0	0	0	0	0	0	0	0
Pad Mounted Switchgear		0	0	0	0	0	0	0	0	0	0	0
Underground Cables (km) (km)		0	0.1	0.2	0.2	0.2	0.2	0.1	0.2	0.4	0.5	0.7

It is evident from Table 5.3-6 that in general, all the asset groups except for pad mounted transformers had fairly level flagged for action plans, indicating small variations in terms of yearly flagged for action numbers.

Pole Inspection

In addition to the ACA, E.L.K. engaged EDM International, Inc. (EDM) to assist with the condition of its pole population. EDM has completed an initial inspection and analysis of 294 E.L.K. poles. The results were used to identify poles for replacement, poles that have defects but not requiring replacement at this time, and poles with no defects. There were 13 poles (4%) identified for Urgent replacement and 14 poles (5%) for medium priority mitigate or replacement. EDM has developed a longer-term plan for pole inspections based on the inspection results and analysis of those results.

E.L.K. Energy (E.L.K.)E.L.K. operates and maintains more than 3,200 wood poles within the Ontario communities of Belle River, Comber, Cottam, Essex, Harrow, and Kingsville. For the 294 poles assessed as part of this ACA, Table 5.3-7 indicate the number of poles per service area:

Table 5.3-7: Pole Service Area Demographic

Area	Quantity
Belle River	50
Comber	33
Essex	51
Harrow	85
Kingsville	75
Total	294

The age distribution of the inspected poles can be seen in Table 5.3-8. Most of these poles were installed before 2000. The oldest pole in the sample was 58 years old.

Table 5.3-8: Pole Age Distribution

Decade	Quantity
1960s	2
1970s	5
1980s	86
1990s	189
2000s	8
2010s	4
Total	**294**

The poles are of different species and treatments which vary based on availability and changes in the industry. The species of poles undergoing inspection are presented in Table 5.3-9.

Table 5.3-9: Pole Species Demographic

Species	Quantity
Jack pine	14
Lodgepole pine	93
Ponderosa pine	2
Red pine	86
Southern pine	64
Unknown	5
Western cedar	30

The performance of different species of wood is dependent on the environmental conditions, manufacturing processes, original treatment, and the individual characteristic of each pole. Individual poles may be damaged when hit by vehicles, snow removal equipment and other equipment.

The priority areas to be inspected in 2020 were determined based on research and information provided by E.L.K.. The groupings were based on operations input, pole age, treatment, size, class, and environmental area. The physical location of poles was also used as a factor. This included whether the poles were set in soil, asphalt or cement and proximity to water. Selections were refined to ensure inspections take place in all areas.

One hundred fifty-seven poles were selected using the methods noted above. The inspectors were provided with criteria to select the remaining poles. This included inspection types, pole age, pole species, and treatments. A total of 294 poles were inspected.

The information gathered from the on-site testing task was used to calculate remaining strength of each pole using D-Calc™. Poles that do not meet the Canadian Standards Association, CSA C22.3 No. 1, "Overhead Systems" clause 8.3.1.3 stating, "When the strength of a structure has deteriorated to 60 percent of the required capacity, the structure shall be reinforced or replaced," were identified for replacement/ mitigation.

Remaining strength calculations and inspector observations were used to determine recommended actions. Table 5.3-10 shows the results of that work.

Table 5.3-10: Remaining Strength Demographic

Recommended Action	Quantity
Less than 25% urgent replacement	13
25-50% Mitigate/replace	14
50-70% Non-restorable	18
50-70% Restorable	23
Greater than 70% maintain	45
Pass	181
Grand Total	**294**

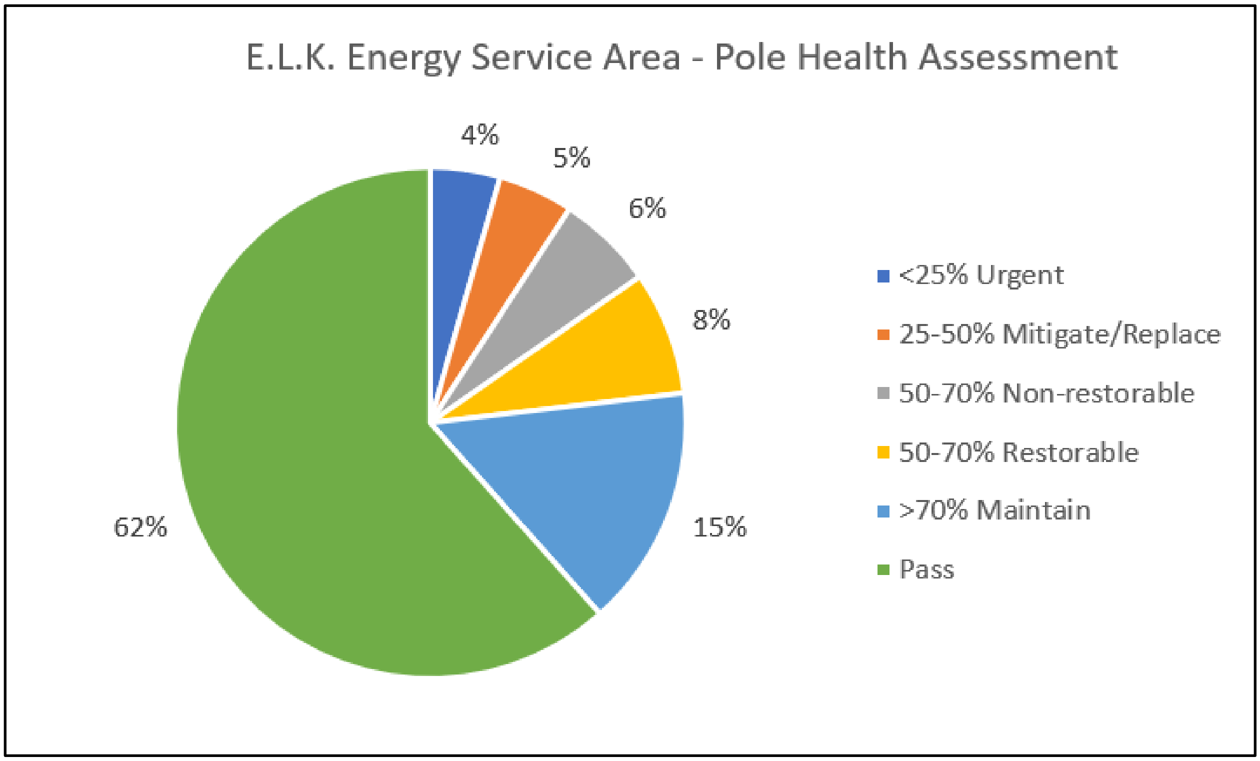


Figure 5.3-15: Pole Replacement Distribution

A comparison of poles requiring replacement/ mitigation as a percentage compared to number inspected is an initial indicator of which community has experienced more degradation of wood poles. The charts below show that Belle River has the highest number of degraded wood poles at 18%, followed by Comber at 15% and Essex at 14%. The sample size is small, making trend analysis difficult. A possible indicator is that older Lodgepole Pine and Red Pine poles are requiring replacement/ mitigation sooner than other species. These species make up 51% of pre-2000 poles inspected but make up 70% of pre-2000 poles requiring replacement or mitigation. Another possible indicator is pole proximity to water. Poles located closer to water are showing more defects.

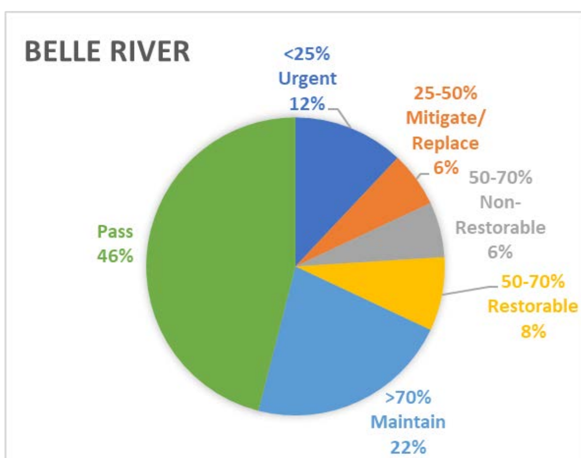


Figure 5.3-16: Belle River Pole Replacement Demographic

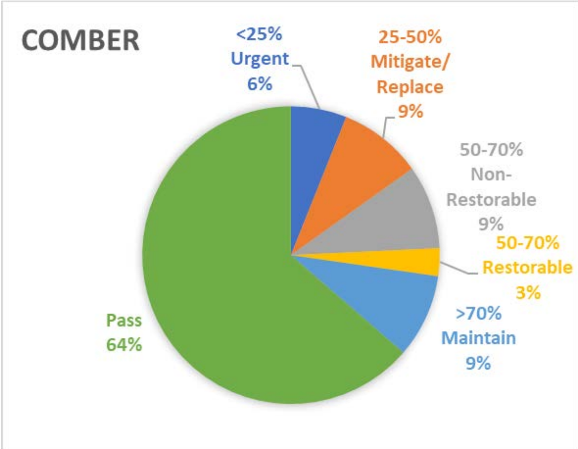


Figure 5.3-17: Pole Replacement Demographic

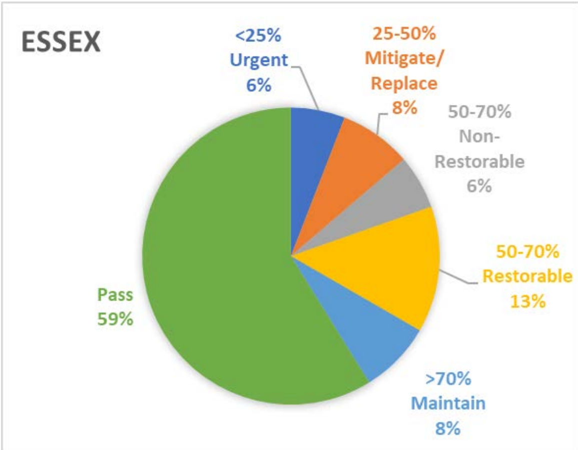


Figure 5.3-18: Pole Replacement Demographic

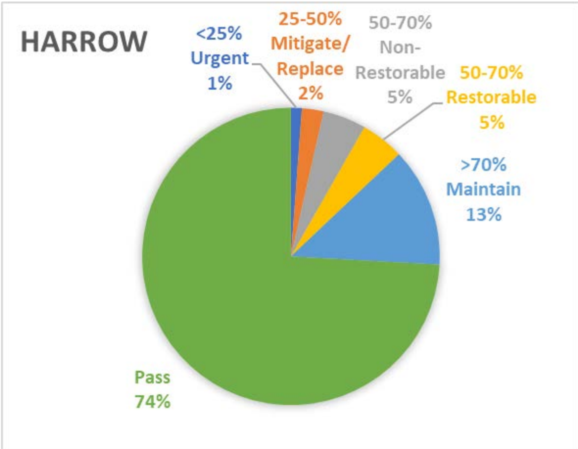


Figure 5.3-19: Pole Replacement Demographic

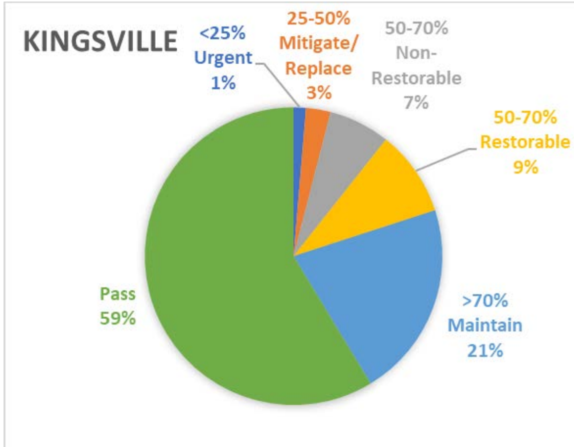


Figure 5.3-20: Pole Replacement Demographic

Overall, the trend shows 9% of the poles inspected will require mitigation or replacement. If the trend continues, just under half of those poles that require replacement will require *urgent* replacement. This high percentage will reduce in future inspections, as the bulk of the defective poles will already be replaced.

5.3.2(d) System Utilization

Apart from the sustainment of existing assets in the distribution system, E.L.K. has considered the needs of potential demand expenditures. They are required to supply the needs of a new customer, or to enhance reliability in an area where system capacity is constrained. E.L.K. has reviewed System Capacity and has also considered population growth, the economy and effectiveness of conservation programs. Within E.L.K.'s distribution system there are no current or foreseen capacity constraints. E.L.K. does not own any substations and is supplied directly by Hydro One, with station capacity managed by Hydro One. As E.L.K.'s service area is comprised of 6 non-contiguous service areas completely embedded in Hydro One, feeder capacity is managed by Hydro One. E.L.K. can connect up to 500kW of new or incremental load without notifying Hydro One. For loads greater than 500 kW E.L.K. must submit a New Customer Connection Information package to Hydro One requesting the capacity be allocated. If or when the capacity is allocated there will be a 1-2 year window to utilize the capacity.

In order to determine how growth might affect the distribution system, a number of areas need to be analyzed. These include population forecasts, the number of new connections, the type of connections, and historical demand. Current steady population growth will not significantly affect the distribution assets within the planning horizon of 5 years.

The Peak Load and Available Generation Capacity are noted in Table 5.3-11 below:

Table 5.3-11: Station Loading and Available Generation Capacity

Station	Feeder	Voltage (kV)	Peak Load (kW)	Capacity Allowance (%)	Generation Capacity (kW)	Existing Generation (kW)	Available Generation Capacity (kW)
Belle River TS	M4	27.6	8624	10	8376	641.66	7734.34
Haycroft DS	F3	8.13	1779	7	1101	95	1006
Kingsville TS	M1	27.6	15354	10	1646	77.41	1568.59
Kingsville TS	M5	27.6	16768	10	232	218.03	13.97
Kingsville TS	M7	27.6	10201	10	6799	10	6789
Kingsville TS	M10	27.6	8902	10	8098	247	7851
Lauzon TS	M24	27.6	16541	10	459	47.58	411.42
Lauzon TS	M29	27.6	13401	10	3599	73.33	3525.67

5.3.3 Asset Lifecycle Optimization Policies and Practices

E.L.K. owns and operates assets within its six service areas and is responsible for the management of all its distribution assets. E.L.K. maintains the efficiency and reliability of its system through an active inspection, maintenance, and asset management process. The objective of E.L.K.'s asset lifecycle optimization policies and practices are to provide the highest quality of service to its customers by ensuring the electrical system it operates is designed, constructed and maintained to ensure its reliability, safety and affordability. The specific description of policies and practices below demonstrates how E.L.K. is able to meet its asset lifecycle objectives.

5.3.3(a) Description of Asset Lifecycle Optimization Policies and Practices

This section describes how E.L.K. assets are managed over their entire lifecycle, from conception to retirement. E.L.K. newly implemented Asset Management Process has informed longer-term planning and predictable investment levels that optimize operational and financial risks. E.L.K.'s approach in Asset Lifecycle Management and planning is holistic in nature and takes into consideration the combined implications of managing all types of physical, financial, and human capital assets.

In identifying policies and practices for lifecycle optimization, along with E.L.K.'s Asset Management Process highlighted in Section 5.3, E.L.K. uses the following assumptions for this DSP:

- Electricity growth rates will continue to be met by the electrical infrastructure that is currently owned and operated by E.L.K., along with proposed enhancements through the System Renewal programs identified in this DSP.
- Recognition that the economy of the Towns of Essex, Kingsville and Lakeshore depends on a secure and reliable supply of electricity.

- The majority of smart meters were installed in 2010. Investments to harness the data produced by the meters will need to be made to promote the "Smart Grid".
- Present service levels will continue to be maintained and will remain a balance between customer needs, price-quality trade-offs, and industry best practice(s). However, there is a certain degree of uncertainty associated with large developments or economic drivers that could trigger unplanned adjustments in the maintenance and inspection of E.L.K.s assets.
- E.L.K.'s asset management systems will continue to evolve, in order to process performance information to meet demand, capacity, security, and reliability levels in a timely manner.
- Compliance with relevant regulatory requirements, as they pertain to electricity rates, filing requirements, health & safety, and environmental protection, will be maintained.
- Asset management planning involves forecasts based on information collected from many sources. Distribution system development for the next five (5) years has been projected and information will become more accurate as work progresses through the five-year plan, allowing E.L.K. to adapt and adjust their plans accordingly.

5.3.3(a).1 Asset Replacement and Refurbishment

E.L.K. considers a wide range of factors when deciding whether to refurbish or replace distribution assets, including but not limited to public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition and life expectancy. All these factors are considered when determining the prudency of any asset replacement or refurbishment.

To optimize equipment value and minimize replacement costs, E.L.K. considers reusing equipment from the field when it is safe to reuse. To ensure that equipment is safe for reuse, E.L.K. complies with *Ontario Regulation 22/04 (Reg. 22/04), Section 6(1)(b) – Approval of Electrical Equipment*. All equipment that has been proposed for reuse must meet certain condition and safety criteria for use by a qualified person within E.L.K..

If it is determined that the equipment cannot be reused, E.L.K. will conduct a repair estimate assessment which identifies the cost of refurbishing the equipment and an estimate of expected remaining useful life. If the cost of repair plus Net Book Value is less than the replacement cost, then the asset is repaired. If the repair costs are greater than the replacement costs the asset is replaced and disposed of appropriately. Where appropriate removed and repaired assets, that are still in good working order, are kept as spares.

5.3.3(a).2 Description of Maintenance and Inspection Practices

Table 5.3-12: Frequency of Maintenance and Inspection Activities

E.L.K. Maintenance/Inspection Activities	Frequency
Visual Inspections	Ad hoc
Planned Inspections	Annually
Infrared Scans	Every two years
Tree Trimming	Annually
Pole Testing	Annually
Vegetation Management	Ad hoc

Condition-based Maintenance	Ad hoc

This section outlines the current maintenance practices undertaken by E.L.K. to maintain customer reliability and power requirements in the system. Some E.L.K. assets require frequent maintenance, some require infrequent maintenance, and some are nearly maintenance free. For most E.L.K. assets, maintenance programs are established for consistency and all maintenance work meets the requirements of *Reg. 22/04* is completed by qualified E.L.K. staff.

Specifically, E.L.K. conducts three types of maintenance programs:

- Predictive Maintenance
    - Visual and Detailed Inspections: this maintenance activity actively assesses the condition of E.L.K. assets at scheduled or ad hoc intervals. Inspection work is primarily completed by E.L.K. employees but is occasionally completed by third party vendors completing field work on E.L.K. assets.
    - Thermographic Infrared (IR) Scans: infrared thermography is completed to allow E.L.K. to identify hard to detect problems or risks within the fleet of assets. E.L.K. conducts IR scans every other year across all service areas.
- Preventative Maintenance
    - Tree Trimming & Vegetation Management: these activities are undertaken by E.L.K. to extend the trouble-free operation of the assets to ensure continual reliability. Tree trimming activities are undertaken on an annual basis, and each service area will have comprehensive vegetation management activities completed on four-year cycles.
- Condition-Based/Reactive Maintenance
    - This is work undertaken by E.L.K. when assets are identified to be out of specifications, malfunctioning or do not meet the requirements of the DSC. The need for these types of maintenance activities to be completed is informed during predictive maintenance activities.

5.3.3.2.1 – Predictive Maintenance Activities

Inspections

Currently, distribution assets are inspected as part of active service work orders that send workers to the field. Inspection of assets during active service work orders results in the creation of databases or workorders and population of an inventory of notifications created during the visual inspections.

In addition to inspections conducted during active service work orders, E.L.K. commissioned the completion of a Pole Inspection Report in October 2020 (Appendix B). Within the findings of the inspection report were recommendations to develop a pole management program and complete future inspection in areas within the E.L.K. system that warranted specific focus, which were those areas with “poor” or “very poor” pole quality. It was also recommended that E.L.K. continue to analyze and gather pole data as more inspections were completed. E.L.K. has included operating expenses into this DSP application to address annual pole inspections, along with towers and fixtures, and the prioritization of these inspections in the first year of the DSP will be determined within the pole management program that is under development.

All of the distribution assets are inspected on a regular basis as prescribed in the DSC. Adherence to the DSC requirements means that E.L.K. will be completed by a third-party vendor on a four-year cycle. All service areas that E.L.K. operates assets within will have detailed inspections completed within the four-year period. While a third-party vendor will be completing the inspections, the documentation and database of service orders and any maintenance required is forwarded to an E.L.K. supervisor for assessment and or to be immediately addressed.

Thermographic Infrared Inspection

E.L.K. undertakes system-wide infrared (IR) thermography of overhead and underground distribution assets. IR thermography is a low-cost method to identify hard to detect problems and risks within the asset fleet. E.L.K. plans to schedule the IR thermography scans every two years, beginning in 2023 for this DSP scope period, and will continue this practice and frequency of predictive maintenance going forward.

5.3.3.2.2 – Preventative Maintenance Activities

Line Clearing and Tree Trimming

E.L.K. has given more attention towards its vegetation management program/tree trimming and is continuing to catch up to incomplete vegetation management from previous years. E.L.K.'s previous approach was that its overhead system gets cleared every four years, with each area gets cleared once a year and the cycle continuing as needed. Going forward, due to the ongoing resource constraints, E.L.K. will employ a third-part contractor to undertake tree-trimming annually starting in 2022. E.L.K. will focus tree trimming activities on a four-year cycle, until the service area has completed a vegetation management cycle. E.L.K. plans to begin in 2022 in the Kingsville service territory.

If growth conditions change or customer requests come in, to trim or remove trees, E.L.K. will utilize third-party vendor services to execute adjustments to the planned vegetation management and tree trimming schedule.

5.3.3.2.3 – Condition Based Maintenance

E.L.K. distribution assets that are identified as requiring attention in the inspection or IR programs will have a service order completed. Service orders are prioritized based on safety and risk when scheduling repair, refurbishment, or replacement. All repairs are tracked and are completed by qualified E.L.K. personnel.

5.3.3(a) Lifecycle Optimization through Maintenance Planning

E.L.K. manages assets with the intent of providing a safe, efficient, reliable, and cost-effective electricity distribution system.

E.L.K. has recently developed an Asset Management Process, described within this DSP, which outlines how data is used within the Asset Management process to help determine what levels of investment is required for maintenance activities and supporting capital expenditures. Going forward, E.L.K. intends to revise its maintenance and inspection practices to a 4-year cycle that will result in inspection of all E.L.K. assets in the 6 service territories over that period. Specifically, E.L.K. plans to execute asset inspections in Kingsville in 2022, Essex in 2023, Harrow and Cottam in 2024, and Belle River and Comber in 2025. E.L.K. may also utilize third-party resources to complete inspections and ensure that all assets are probably investigated in the timelines identified in E.L.K.'s developing maintenance and inspection practices. Third-party inspection support will commence in 2022 within this DSP application.

5.3.3(b) Asset Lifecycle Risk Management Policies and Practices

E.L.K.'s lifecycle risk management strategy is aimed at protecting the public from physical, electrical, and environmental hazards, by maintaining a schedule of regular asset inspections and maintenance activities. The objectives of E.L.K.'s maintenance activities are outlined in the Asset Management Process. Specifically, E.L.K. prioritizes maintenance work that could have physical, electrical and environmental safety implications for follow-up repairs or assessment. If assets cannot be repaired, refurbished or replaced immediately then the information is fed into E.L.K.'s asset database and incorporated into capital plan for future scopes of work to be completed under the approved investment plan. Further details of its maintenance policies and practices can be found in section 5.3.3(a).

Ontario Regulation 22/04 - Electrical Distribution Safety is a key regulation which requires E.L.K., and all other LDCs, to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. The Electrical Safety Authority (ESA) is responsible for enforcing the regulation through a system of annual audits and regular field inspections.

E.L.K. promotes excellence in health and safety management in order to prevent losses to people, assets, environment, and reputation. Key to this H&S Management system are the evaluation of risk for all workplace hazards, regular H&S meetings with staff, and feedback on losses or near losses occurring in the workplace.

5.3.4 System Capability Assessment for REG

5.3.4(a) Applications for REG Connections Greater than 10kW

As of November 30, 2021, there are no current applications from renewable generators over 10kW for connection in the E.L.K.'s service area.

5.3.4(b) Forecast of REG Connections

There are a total of 168 renewable energy generation installations presently connected to E.L.K.'s distribution system under the province's Feed-in-Tariff ("FIT") and micro-FIT programs. In summary E.L.K. has:

- 8 FIT installations with generating capacity of 2.44 MW, listed in Table 5.3-5
- 155 micro-FIT installations with 1.37 MW installed capacity, as shown in Table 5.3-6

- 5 solar net-metering installations with 45 kW installed capacity.

In addition to the above, there are 2 Net Metering projects in the Applications progress but have not yet proceeded to the development stage. There are currently no other applications in queue waiting for connections.

E.L.K. continues to perform connection impact assessments for Net Metering application. However, there are currently no additional applications in the queue. E.L.K. expects an equal or a smaller number of REG applications over the rate filing period to what has been connected to date due to the reduced incentives and the limited participation to date. E.L.K. does not currently anticipate any other renewable generation connections over the forecast period.

5.3.4(c) Capacity Available

E.L.K. has system capacity and will be able to accommodate the REG connections within the five-year planning period. However, there may be limitations with respect to the transmission and distribution stations owned by Hydro One. E.L.K. Energy will continue to offer microFIT connections until formally notified otherwise by Hydro One. FIT connections are subject to impact assessments which will identify any issues prior to an offer to connect. E.L.K. Energy Inc. has established limits for the amount of generation on each of its seven 27.6kV M class feeders and two 8.13kV F class feeders. These capacities are based on 10% and 7% respectively of the feeders peak load. The Peak Load and Available Generation Capacity are noted in Table 5.3-11.

5.3.4(d) REG Constraints

Currently E.L.K. is not aware of any constraints for renewable generation connections within its distribution system. There may, however, be limitations with respect to the transmission and distribution stations owned by Hydro One. E.L.K. Energy Inc. has established limits for the amount of generation on each of its seven 27.6kV M class feeders and two 8.13kV F class feeders. These capacities are based on 10% and 7% respectively of the feeders peak load. The Peak Load and Available Generation Capacity are noted in Table 5.3-11.

5.3.4(e) Embedded Distributor Constraints

E.L.K. has no embedded distributors.

5.4 CAPITAL EXPENDITURE PLAN

5.4.0.1 Capital Expenditure over the Forecast Period

Table 5.4-1: Gross Planned Capital Expenditures by Investment Category ($ ‘000)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Access	867	942	1,108	1,144	1,183	**1,049**
System Renewal	307	370	452	494	539	**432**
System Service	42	42	42	42	83	**50**
General Plant	419	609	244	227	56	***311***
Total Expenditure	**1,634**	**1,963**	**1,845**	**1,906**	**1,862**	***1,842***

5.4.0.2 Capital Planning for 2022-2026

5.4.0.2.1 System Access

Expenditures within the System Access category are driven by external requirements such as servicing new customer loads and relocating distribution assets to suit road or municipal authorities. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. Most of the forecasted investments in this category are based on historical averages, while being supported by information from external agencies and municipalities in the E.L.K. service territory.

Table 5.4-2: Forecasted System Access Investments ($'000)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Access	867	920	1,108	1,144	1,183	**1,049**

There are two main categories that E.L.K. anticipates System Access investments to fall into: Subdivision development and rebuilds. Subdivision developments including new electrical supply and materials to residential and commercial developments where no current supply exists. System Access rebuilds include the relocation or enhancement of assets because of infrastructure development driven outside of an E.L.K. need, such as road rebuilds.

5.4.0.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. E.L.K. conducted both an asset condition assessment and pole health assessment to inform decisions for System Renewal within this DSP. The output of these assessments and processes led to targeted programs for capital expenditure and prioritization of System Renewal.

Table 5.4-3: Forecasted System Renewal Investments ($'000)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Renewal	307	370	452	494	539	**432**

There are two major focus areas for E.L.K.'s System Renewal activities: transformer replacements and upgrade, and pole replacement and treatment. As part of these asset renewal projects, E.L.K. intends to replace on average 18 poles per year that are in "very poor" or "poor" health condition as well as undertake treatment activities on other at-risk poles in the service territory. Additionally, for the transformer replacement project, E.L.K. intends to identify and replace degraded or end of useful life transformers within the system. These investments are aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers.

5.4.0.2.3 System Service

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet its operational objectives, while being able to anticipate future customer electricity requirements. Investments in System Service are captured in the table below.

Table 5.4-4: Forecasted System Service Investments ($'000)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
System Service	42	42	42	42	83	**50**

The main investment activity comprising System Service for E.L.K. within this DSP is the installation and deployment of fault circuit indicators onto the distribution lines in E.L.K. service territories. E.L.K. forecasts deploying ten sets of fault circuit indicators per year starting with a test year in Kingsville service territory, with 20 sets being installed across two service areas in 2026. These fault indicators will allow for more accurate visibility on faults within the distribution system to identify targeted areas for power service restoration and monitoring.

5.4.0.2.4 General Plant

Expenditures in the General Plant category are driven by the need to modify, replace or add to assets that are not part of the distribution system but support E.L.K.'s daily operations. The items within this category are important and contribute to the safe and reliable operation of a distribution system. If General Plant investments are ignored or deprioritized this could lead to future operational risks or increased investments in future years. E.L.K.'s planned capital investments in General Plant are highlighted in the table below.

Table 5.4-5: Forecasted General Plant Investments ($'000)

Category	2022($)	2023($)	2024($)	2025($)	2026($)	Avg. ($)
General Plant	419	609	244	227	56	***311***

The main investment activity with the General Plant category will be the procurement of two large new fleet vehicles for the E.L.K. fleet. Previous units have reached end of useful life and need to be replaced, which leads to the large capital investments in 2022 and 2023. Procurement of the chassis for both vehicles is expected in 2022, with the balance of the costs and delivery of the units anticipated in 2023. The delivery of these fleet vehicles will allow E.L.K. to safely operate and maintain the distribution system across its service territories. In addition, supported by feedback from customers, E.L.K. will be undertaking a comprehensive review and upgrade of various IT systems during 2022. The IT strategy is planned to include a new GIS system, integration of an Outage Management System (OMS), improvements to E.L.K.'s website, and the generation of Outage Maps for E.L.K. customers. These are considered fundamental systems that are required to track and monitor important information about assets and the overall system. This is also considered good utility practice as demonstrated by the implementation of similar systems by other distribution companies in Ontario and beyond. The new website design, mobile app and green button project are beginning in late 2021 and continuing into 2022.

5.4(a) Customer Preferences

5.4(a).1 Customer Engagement

E.L.K. regularly seeks to obtain customer feedback to help inform the direction and prioritization of future capital investments in the E.L.K. system. The objective for E.L.K. is to facilitate access so that customers can easily contact and communicate with the utility, and E.L.K. does through customer-facing representation and a culture of leadership that delivers distribution service excellence to both customers and employees.

As discussed in section 5.2.2.1.1 Customer Engagement, E.L.K. maintains multiple communication channels to engage with its customers, including a recent open-door policy to the head offices to allow physical interaction with E.L.K. staff and serviced customers. Along with customer satisfaction and safety surveys that are completed on a yearly basis, E.L.K. is continued to expand the communication channels to its customers.

Specifically for this DSP, E.L.K. completed a customer survey to outline the proposed capital investments associated with this DSP and to solicit feedback for general satisfaction of service and reliability of E.L.K. customers.

5.4(a).2 Customer Preference

The customer engagement process has yielded results consistent with what E.L.K. anticipated and has heard through face to face and interactions on social media. There are a few key learnings that have emerged from these engagements:

- E.L.K. has room for improvement with regards to customer satisfaction, with a particular focus on reliability. Customer engagement validated this learning and specific feedback stated that reliability, particularly in the Kingsville and Essex service territories, was poorer than in previous years and the outage and restoration times had also grown. Furthermore, consumers felt they did not receive adequate communication for outages that were planned, let along the restoration activities associated with unplanned outages.

- The majority of E.L.K. customers support the capital investments in areas of System Renewal and General Plant, but priority had to be focused on the impacts and improvements those investments would have on service reliability and availability of power.

The feedback from customers and capital investment plans identified in this DSP are consistent, and E.L.K. believes these investments would deliver upon the priorities of their customers. The priorities identified from the customer engagement are:

1) Ensure reliable electric service
2) Deliver electricity at reasonable prices
3) Prioritize investments that will help improve system reliability, power quality, utility efficiency and operations.
4) Reduce the overall number of outages

5.4(a).3 Project in Response to Customer Preferences, Technology and Innovation

In direct response to customer preferences identified in the customer survey, E.L.K is not introducing any additional projects or modifications to existing projects. The results of the surveys supported the direction that E.L.K is taking for projects identified within this DSP but did not lead to the creation or identification of new scopes of work to meet customer demand.

5.4(b) System Development over the Forecast Period

5.4(b).1 Ability to Connect New Load/Generation

Across all stations, E.L.K. has available capacity for new load and generation connections. The available feeder capacity for generation is summarized in Table 5.3-11

5.4(b).2 Load and Customer Growth

E.L.K undertakes load studies, which allow E.L.K. to identify areas that may require investments to accommodate required capacity. E.L.K. has experienced a significant level of customer connections over the last five years. Based on the information E.L.K. has received from developers and town councils, it is expected that this increase in number of customers, development of subdivisions will continue to grow over the 2022-2026 forecast period. The number of subdivisions and average number of connections are detailed in the System Access Material Narratives. E.L.K. will continue to evaluate the growth and expected load growth, identifying any projects required to increase capacity. Engagement with Hydro One will continue as E.L.K. are embedded within Hydro One and do not have control of the capacity of the four stations that supply bulk power, and therefore any station capacity increase needs to be undertaken by Hydro One.

5.4(b).3 Grid Modernization

E.L.K. is undertaking one grid modernization project included within this DSP application. This project will deploy fault circuit indicators onto the conductors of some E.L.K. distribution lines throughout the service territory. These fault circuit indicators will allow for real time monitoring of current on the conductor and identification of any faults that may occur on the system in real time. The fault indicators include a lighting system that will assist field crews in quickly identifying the location of faults or areas that require addressing. E.L.K. anticipates using the Kingsville region as a pilot area for deployment of the first set of fault indicators, due to known reliability concerns in the area. It will then roll out deployment across its other five regions.

5.4(b).4 REG Accommodation

E.L.K. is supplied by four HONI owned TS. HONI maintains their TS's, and as of the last discussions with Hydro One, have no plans to further modify the stations specifically for renewable generation capacity. However, approximately one new net-metering services has been installed each historical year. Hence, E.L.K. projects to connect similar to historical levels of new net-metering service a year over the 2022-2026 forecast period.

5.4(b).5 Climate Change Adaption

Currently, E.L.K. does not expect to make any investment relating to climate change adaptation. E.L.K. will continue to assess and review best practices and look to implement changes that are deemed a benefit and can hep address any issues due to the effects of climate change.

5.4.1 Capital Expenditure Planning Process Overview

5.4.1(a) Analytical Tools and Methods Used for Risk Management

The following information provides an overview of E.L.K.'s capital expenditure planning process which includes details on planning objectives, planning criteria and assumptions used in the development of the capital expenditure plan. The asset management process is the foundation to the DSP and the capital expenditure plan, which helps align each to overall corporate objectives. By following a strategic approach to the capital expenditure planning process E.L.K. achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers and providing the highest level of shareholder and customer value.

In the development of the capital expenditure plan, a number of objectives and planning processes are observed and adhered to in order to align the plan with the goals and overall strategic direction of the company. E.L.K.'s planning objectives that have informed the DSP and capital expenditure plan include:

- Ensure allocation of investments to meet regulatory obligations of the System Access such as metering, system relocations for municipal road work, and future system requirements for residential, commercial and industrial customers.

- Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system.

- Ensure proper allocation of investments in General Plant assets to support investment initiatives.

- Undertake a fault indicator program to ensure it can monitor and manage unplanned outages more effectively; and

- Review overall expenditures and determine impacts to financials and adjust spending as required to ensure impact on customer rates are minimized where possible.

The level of investments required for System Access projects is determined through consultations with the municipal government and based on the number of anticipated development and building permits for residential and commercial construction. The System Renewal investments are determined through asset condition assessments and the identification of economically efficient investments. The level of investments required for General Plant are determined through the assessment of its E.L.K.'s fleet, facilities and IT systems, reviewing the age, obsoleteness and industry best practices for these areas.

E.L.K. will undertake the deployment of fault circuit indicators onto the distribution lines in its service territories. These fault indicators will allow for more accurate visibility on faults within the distribution system to identify targeted areas for power service restoration and monitoring.

E.L.K. engages with customers to ensure that planning processes for capital and maintenance work is in line with customer expectations and to understand the risks that need to be addressed. These engagements include meetings with municipal teams, information sessions, open houses, customer class specific meetings and the bi-annual customer satisfaction survey. E.L.K. also conducts informal engagements such as front-line staff and management listening to customers at the front desk and operations staff working with customers and contractors on day-to-day projects. The continued message from customers is for E.L.K. to continue providing safe and reliable service, improve reliability in service areas where reliability has been affected in the past, and to mitigate rate increases where possible. Some customers, however, have accepted that rates may go up as long as the reliability in their service areas is improved to the level they expect. E.L.K. undertook a DSP customer survey in 2021 to identify customer priorities for the 2022-2026 period. Below are the top customer priorities identified that E.L.K. has used in the development and prioritization of its investment plan for the 2022-2026 period.

1) Ensure reliable electric service
2) Deliver electricity at reasonable prices
3) Prioritize investments that will help improve system reliability, power quality, utility efficiency and operations.
4) Reduce the overall number of outages

E.L.K. works closely with the Municipality and other utilities as demonstrated in section 2.3 Coordinated Planning with Third Parties within the DSP. When rebuilding infrastructure placing assets underground is must for projects such as road relocations. E.L.K.'s policy is to install underground services up to the lot line.

5.4.1(b) Processes, Tools & Methods

With E.L.K.'s Mission being *"to provide the highest quality service to our customers by ensuring that the electrical system is designed, constructed and maintained to ensure its reliability, safety and affordability while increasing shareholder value",* E.L.K. has developed a prudent capital budget process and system of prioritization. This process considers E.L.K.'s long-term investment strategy, recognizes shorter-term requirements, and enables E.L.K. to address changes in external and internal priorities. This process also takes into consideration the priorities of a wide range of stakeholders, E.L.K.'s corporate strategies as well as legislative and regulatory requirements. *Figure 5.4-1* illustrates E.L.K.'s Capital Expenditure Process at a high level.

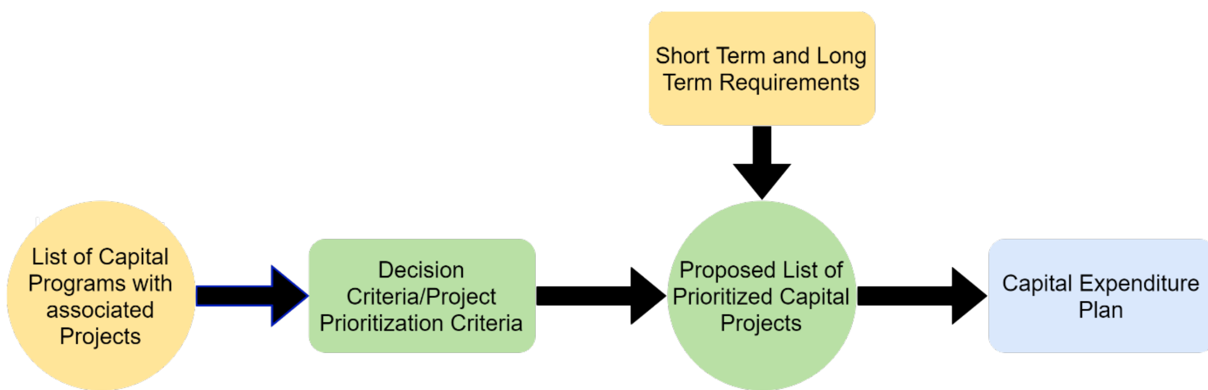


Figure 5.4-1: E.L.K. Capital Expenditure Process

E.L.K. projects can either be categorized as non-discretionary or discretionary. Non-discretionary projects are automatically selected and prioritized based on externally driven schedules and needs. System Access projects fall into this category and may involve multi-year investments to meet customer or developer requirements. Projects that reside in System Renewal, System Service, and General Plant are typically categorised as discretionary. These projects are prioritized based on risk associated with not undertaking each project, and the resource and budget available to deliver those projects. Where appropriate, E.L.K. looks to group projects into programs, mainly within its System Renewal category. For example, each year E.L.K. needs to replace a number of poles that have reached end of life and/or in poor and very poor condition. These investments fall within E.L.K.'s Pole Replacement Program.

The identification, selection and prioritization processes completed within each of the OEB investment categories are briefly described in the following sub-sections.

5.4.1(b).1 System Access

System Access projects are non-discretionary in nature and are therefore a high priority for E.L.K.. Projects are identified through contact with customers wishing to connect new services or through requests from municipal landowners to relocate assets to accommodate road construction projects. Within this category, project prioritization is based on the expected date when all service requirements will be fulfilled by the customer, as identified through regular contact between parties. Projects are paced to ensure that low voltage connections are completed within five days of the fulfillment of all service conditions and high voltage services are connected within ten days of the fulfillment of all service conditions. E.L.K. works closely with the municipal planning departments to ensure that adequate budgeting, planning and resourcing is in place to accommodate System Access projects.

5.4.1(b).2 System Renewal

E.L.K. identifies System Renewal requirements through its asset database, outage information, useful life of assets, and asset condition assessment for key distribution system assets. Projects are identified, selected, prioritized, and paced by considering the following:

- System Reliability Impact
- Safety Impact
- Asset Condition and End of Life (EOL) categorization

E.L.K.'s decisions on asset replacement and refurbishment are based on asset conditions, age and outage statistics. Therefore, System Renewal investments proposed in this DSP include proactive replacements to address targeted assets identified in the review. System Renewal investments involve replacement and refurbishment of system assets to maintain the system's ability to provide safe and reliable electricity services to customers. As assets become aged and reach EOL, these investments are necessary to rectify and maintain the overall asset health condition at an acceptable level to prevent decline in system reliability performance and mitigate safety risks to E.L.K. employees and the public.

System Renewal projects are typically the highest priority for E.L.K. after System Access projects.

5.4.1(b).3 System Service

Due to the nature of E.L.K.'s current distribution system, E.L.K. does not typically undertake any System Service projects. E.L.K. has not undertaken any System Service projects historically. However, E.L.K. has identified a need to undertake a System Service project during the 2022-2026 period. E.L.K. has used customer feedback, data on its system reliability, and the number of outages it has experienced to identify the need to undertake a project that will enable it to better manage outages and help identify areas where investment is required to improve reliability.

5.4.1(b).4 General Plant

General Plant projects are identified and assessed using a combination of inspections, policies, industry best practice, and expert knowledge. Projects included in this category include investments related to E.L.K.'s vehicle fleet, operational tools, facilities, and IT equipment and software.

Fleet

E.L.K. manages a fleet of vehicles that are essential to the efficient and effective day-to-day operation of the utility. This fleet includes bucket trucks, a radial boom derrick (RBD), underground service truck, dump truck, various trailers, small pickup trucks and SUV's. It is crucial that all fleet vehicles are maintained properly and replaced in a timely manner. This requires balancing new vehicle purchase costs against excessive repair bills and operational downtime that occur when vehicles are out of service for too long. E.L.K.'s fleet vehicle replacement determination considers the following factors:

- Age of the vehicle,
- Odometer reading,
- Maintenance costs,
- Annual vehicle test results, including stress/electrical testing,
- Practicality of existing vehicle including new technology available,
- Changing emissions, weight, and road safety regulations obsoleting some existing units, and
- Crew/Crew/another department needs.

When the age of the vehicle approaches its end of life, a case-by-case evaluation is done to determine whether or not replacement is an option ahead of or later than the vehicles normal life expectancy.

In addition, odometer readings are considered when contemplating vehicle replacement. Generally, when a vehicle reaches 100,000 km, a vehicle's residual value drops significantly, and maintenance costs will begin to increase.

Vehicle testing includes bucket trucks and RBD's that are tested annually for insulation resistance – the main electrical property of the boom assembly and structural stability. If significant work is required to maintain the unit within specifications, this could drastically impact planned vehicle replacement timelines. In addition, changes to provincial vehicle regulations can impact residual values through changes in planned or existing use limitations for large fleet vehicles.

Operational Tools

This category is used for the purchase of tools and equipment where the cost generally exceeds $1,000. E.L.K. continually looks at upgrading outdated tools and equipment and looks for newer more effective technology that will result in more efficient work practices, combined with the most ergonomic way of accomplishing a task. Decisions requiring the selection and prioritization of these investments are made using expert knowledge and observing changes to industry best practices, as well as balancing the costs of the purchases with the anticipated reduction in work effort. An example of an operational tool is an infrared camera that can be used as part of the inspection regime.

Facilities

Investments in this category are identified through inspections carried out on the building assets, expert opinion and through observing, noting and repairing issues throughout the building. Investment levels for maintenance items are based on typical and historical expenditures and include items such as interior and exterior lighting, asphalt, doors and fixtures, HVAC maintenance, yard maintenance, parking lot repair, security system maintenance and building mechanical systems. Investments are also planned based on utilization of the existing building and fixtures. For example, expansion of the building may be required if personnel and equipment needs are forecasted to increase beyond what can be reasonably accommodated by the existing assets.

IT Equipment and Software

Projects are grouped into Hardware and Software. Annual IT capital projects are based on identified need in the organization, best practices in network and security systems, expert knowledge and feedback received from employees. Projects are selected and prioritized in order to maintain effective and efficient business processes, ensure support for disaster and business continuity and to maintain integrated and reliable enterprise solutions. Planning of IT capital expenditures is based on estimated life cycle of both hardware and software as well as the expertise of IT professionals.

5.4.1(b).5 Senior Management Review

Following the identification, selection & prioritization processes under each investment category, the final decision on prioritizing projects and programs resides with E.L.K.'s senior management team. Senior representatives from both the operations and finance teams use a scoring guide to help with investment prioritization across the company as a whole. In all cases, non-discretionary projects and projects relating to safety and/or regulatory compliance have the highest priority. E.L.K. aligns its scoring/priority rankings with its AM objectives, which are described in more detail in Section 5.3 and shown in Table 5.3-2.

5.4.1(c) REG Investment Prioritization Method & Criteria

E.L.K. does not use a separate prioritization for REG investments. In addition, E.L.K. assesses that the distribution system has sufficient capacity to accommodate foreseeable renewable generation connections within the period covered by the DSP. E.L.K.'s planning objective concerning renewable generation is to continue to facilitate the connection of renewable generation promptly consistent with the provisions of the DSC.

5.4.1(d) Alternatives for System Capacity Planning and Operational Constraints

E.L.K. considers all viable alternatives for resolving system capacity issues or operational constraints. For all identified issues and constraints, a "do-nothing" alternative is considered, in order to determine whether the risks associated with the issue/constraint merit any significant investment. Once a capacity issue or operational constraint has been identified for which "do-nothing" is not an acceptable approach, E.L.K. considers all reasonable alternatives to resolve the issue. E.L.K. does not expect any capacity related issues within the distribution system over the 5-year planning horizon. The Regional Planning Process has played a role in assessing alternatives and resulted in a more formal approach for upstream transmission system capacity constraints.

5.4.1(e) System Modernization

E.L.K. plans to modernize its grid by replacing assets that no longer meet E.L.K.'s design standards with assets that meet the latest standards. E.L.K. assess the use of new technologies on a project-by-project basis to determine if it is value for money. As E.L.K. is a small utility, there are some solutions that other utilities use, such as automated switching, that are not appropriate for E.L.K. to use. E.L.K. continues to assess these types of options, but system modernization depends on multiple factors and limits and is evaluated on a project-by-project basis.

One project that will significantly enhance E.L.K.'s ability to respond effectively and efficiently to customer outages is the deployment of fault indicators within the service territories. E.L.K. forecasts deploying ten sets of fault circuit indicators per year starting in 2022 in the Kingsville service territory, with 20 sets covering two service areas being completed in 2026. These fault indicators will allow for more accurate visibility on faults within the distribution system to identify targeted areas for power service restoration and monitoring.

E.L.K. will support improved safety, reliability and operational effectiveness by proactively replacing assets that are at increased risk of failure, including poles, transformers and fleet vehicles. E.L.K. will also be undertaking a comprehensive review and upgrade of various IT systems over the forecast period in order to improve communications, outage notifications and overall customer satisfaction. The IT strategy is planned to include a new GIS system, integration of an Outage Management System, improvements to E.L.K.'s website, and the generation of Outage Maps for E.L.K. customers.

5.4.1(f) Conservation and Demand Management ("CDM") Programs

This program has now finished. E.L.K. has a couple of outstanding programs that are near completion.

5.4.1.1 Rate-Funded Activities to Defer Distribution Infrastructure

E.L.K. does not currently have any example of any programs or activities that it will be undertaking in its forecast period. E.L.K. will continue to assess and monitor this.

5.4.2. Capital Expenditure Summary

5.4.2.1 Plan vs Actual Variances for the Historical Period

Table 5.4-6: Historical and forecast capital expenditures and system O&M

Category	Historical														
	2017			2018			2019			2020			2021		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.*	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access (gross)	560	614	10%	677	558	-18%	694	875	26%	711	726	2%	729	659	-10%
System Renewal (gross)	262	174	-34%	295	513	74%	459	45	-90%	476	492	3%	301	152	-49%
System Service (gross)	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%
General Plant (gross)	492	28	-94%	457	34	-92%	457	174	-62%	177	539	205%	337	474	41%
Total Gross Expenditure	1,314	815	-38%	1,429	1,105	-23%	1610	1094	-32%	1,365	1,757	29%	1,367	1,286	-6%
Total Net Expenditure	699	573	-61%	872	932	7%	735	393	-47%	283	1,227	333%	395	818	107%
Contributed Capital	(614)	(242)	-61%	(557)	(172)	-69%	(875)	(701)	-20%	(1081)	(530)	-51%	(972)	(468)	-52%
System O&M	1542	911	-41%	1413	969	-31%	1478	1086	-27%	1455	864	-41%	1462	925	-37%

** Estimated actuals up to December 10, 2021.*

Table 5.4-7: Forecast capital expenditures and system O&M

Category	Forecast				
	2022	2023	2024	2025	2026
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access (*gross*)	867	943	1,108	1,144	1,183
System Renewal (*net*)	307	370	452	494	539
System Service (*net*)	42	42	42	42	83
General Plant (*net*)	419	609	244	227	56
Contributed Capital	(468)	(477)	(487)	(497)	(507)
Total Gross Expenditure	1,634	1,963	1,845	1,907	1,862
Total Net Expenditure	1,166	1,486	1,358	1,410	1,355
System O&M	1,447	1,476	1,505	1,535	1,566

5.4.2.2 Variances in Capital Expenditure

Assessing and understanding the variances is an important step for E.L.K. to promote continuous improvements in its estimation and budgeting process. Excluding projects identified as mandatory, E.L.K. creates each project budget based on preliminary designs and historical costs for planning its programs annually. Once detailed designs are complete and ready to be issued for construction, the project estimate is revised to reflect any changes in the design. The revised estimate is used to track against the actual costs, which are currently reviewed quarterly. E.L.K. will move towards monthly tracking and monitoring in the future if it is deemed beneficial. Customer demand projects are budgeted using averages from previous years. These projects are mostly unplanned and tracked in real-time to balance the total annual budget with other discretionary projects, meaning that E.L.K. may take action to reduce System Renewal projects to ensure the total annual actual expenditures remain in line with the total annual proposed budget. Likewise, if the actual System Access budget is less than the forecast budget in a given year, E.L.K. may decide to reallocate the remaining budget to other System Access planning years or to other investment categories where appropriate to maintain the overall annual expenditures within the OEB approved amounts while continuing to meet system needs.

In the following sub-sections, variance breakdowns between forecast and actual costs over the historical period are provided for each investment category by year. Variances that exceed +/- 10% in a given year are explained and are in reference to Table 5.4-6.Although some variances appear significant under certain categories, the overall actual spending in each year is less than the forecast amount. This means that E.L.K. was able to control cost and minimize customer bill impacts while addressing the system needs and intended performance. Year-over-year variance explanations can be found in Exhibit 2.

It should be noted that E.L.K.'s previous DSP forecast was not approved by the OEB since E.L.K. agreed to withdraw their COS application and to instead use an Annual IR Index methodology to set base rates. However, in accordance with the Chapter 5 filing requirements, E.L.K. has provided a variance analysis for the last five years (2017-2021) based on the forecast numbers that were submitted as part of the last DSP filing. Analysis of the 2012-2016 variance was previously submitted as part of the last COS filing.[2]

System Access

System Access projects are customer-driven and are typically not planned. They are budgeted based on a rolling five-year historical average. System Access expenditures can be categorized into smaller categories such as road relocations, subdivision connections and service requests. No sub-category can be planned for with a high degree of accuracy. However, E.L.K. attempts to minimize the variances with proactive engagements with developers, city departments and customers. E.L.K. is often aware of future proposed subdivisions and road relation projects, but development can often be slow, and projects may remain in the preliminary stages for many years before implementation which is beyond E.L.K.'s control. Over the five years, E.L.K. has overspent (2%) against the original DSP forecast expenditure.

[2] This approach was approved by the OEB in a letter dated April 12, 2021 regarding E.L.K.'s 2022 Cost of Service Application. OEB Response Letter

System Renewal

Overall, across the 2017-2021 period, E.L.K. has managed its System Renewal expenditure to ensure it stays within its overall budget allocations. E.L.K. assesses its overall budget each year to ensure that any changes in spend due to System Renewal projects did not impact the overall forecast expenditure target. This has ensured that bill impacts have been minimized and E.L.K. has managed its budget prudently. Across the five years, E.L.K.'s actual spend is around 23% underspent when compared to the original DSP five-year forecast expenditure.

2017 Budget Variances (-34%)

E.L.K. underspent on its system renewal program in 2017, mainly due to a slight increase in the number of system access projects required to be delivered. System Access projects are prioritized by E.L.K. as these are non-discretionary, mandatory projects. In addition to these projects, this meant that E.L.K. did not have enough resources to deliver all the planned projects for 2017.

2018 Budget Variances (74%)

E.L.K. identified a number of projects, originally scheduled for 2019, that required to be brought forward into 2018. This was mainly due to two reasons: to enable efficiencies by undertaking work in the same area on multiple projects rather than return the following year, and the identification of assets that were at risk of immediate or near-term failure. E.L.K. identified planned investments due to be completed in 2019 and prioritized the highest risk projects for completing in 2018. This mainly related to an increased number of Pole and transformer replacements.

2019 Budget Variances (-90%)

Due to the increase in System Renewal expenditure in 2018 from advancing the 2019 projects forward by a year, E.L.K.'s actual System Renewal expenditures in 2019 were lower than originally forecast. This approach has allowed E.L.K. to stay within its overall five-year System Renewal budget. In addition, there was a slight increase in System Access projects required to be undertaken that E.L.K. prioritizes over all other investments.

2021 Budget Variances (-49%)

Due the ongoing COVID-19 pandemic, this has impacted supply chains significantly, with the material that E.L.K. require to complete its planned system renewal projects having long lead times. This has resulted in E.L.K. needing to defer certain projects until the material arrives. E.L.K. has prioritized projects that have the highest criticality where possible. E.L.K. will continue to manage these supply chain issues, and put in places mitigation where possible, including reprioritizing projects depending on their criticality and the material available.

System Service

E.L.K. has not undertaken any System Service projects in during the historical period.

General Plant

2017 Budget Variances (-94%)

The reason for the General Plant underspend in 2017 is that the planned replacement of the boom truck and SUV was delayed until 2019, mainly due to the long-lead time for the complete delivery of both vehicles.

2018 Budget Variances (-93%)

A number of other General Plant projects, including an IT replacement and other facility upgrades, were delayed. This reason for reduction, was to allow for an increase in critical System Renewal projects that were required to be carried out in 2018.

2019 Budget Variances (-62%)

The reason for the General Plant underspend in 2019 is that the planned replacement of a bucket truck was delayed until 2020. This was mainly due to a delay in the order of the vehicle, and the long lead times quoted by the provider.

2020 Budget Variances (205%)

The delayed bucket truck that was initially due for replacement in 2019, was replaced in 2020. In addition, a dump truck was also replaced in 2020 resulting in a significant General Plant overspend in 2020.

2021 Budget Variances (41%)

Based on current actuals to the end of August 2021, E.L.K. has overspent against the original forecast. This is due to the replacement of a double bucket truck, a SUV pickup, and a new dump truck.

5.4.3 Justifying Capital Expenditures

5.4.3.1 Overall Plan

The make-up of E.L.K. ‘s overall capital plan consists of many converging inputs that drive and influence the direction of the capital expenditures. E.L.K.’s objective with regards to capital expenditures is to meet all regulated requirements while managing the assets in a manner that minimizes the costs to E.L.K. customers and ratepayers.

5.4.3.1.1 Comparative Expenditures by Category Over the Historical Period

System Access

The historical trend with System Access is variable year over year due to the unpredictability of customer connection service requests, externally initiated relocation projects, and metering upgrades. As shown in Figure 5.4-2, the forecast average for E.L.K. System Access is 50% greater than the historical average. This is due to some known customer growth areas in E.L.K.’s service territory as well as allowing E.L.K. to allocate adequate resources and funds to accommodate potential future unknown connections. However, these projects are difficult to forecast and may still change as these are dependent on customer and external drivers.

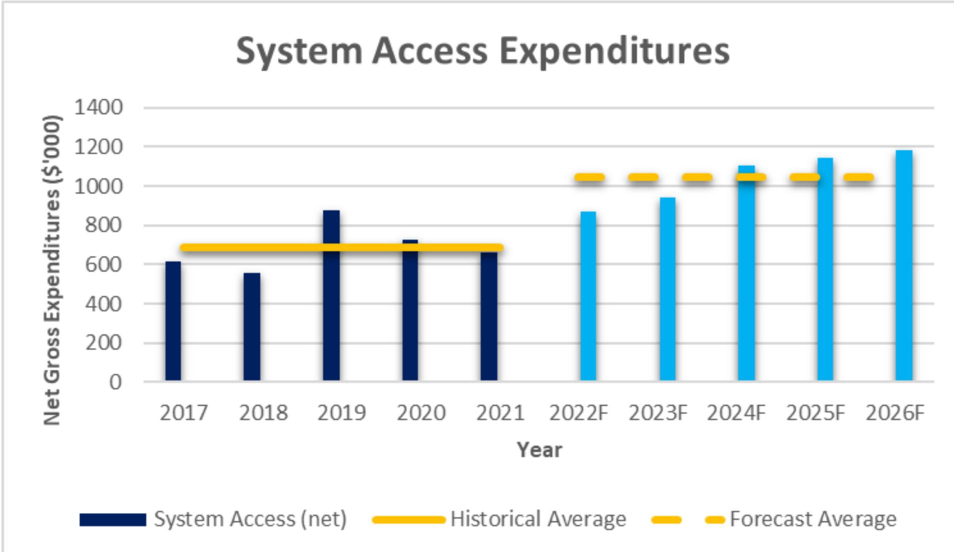


Figure 5.4-2: System Access Comparative Expenditures

<u>System Renewal</u>

Expenses in System Renewal are impacted by planned capital investments and the objective to address any condition-based maintenance activities within the asset system to meet customer's expected performance and reliability. As shown in Figure 5.4-3, the forecast average for System Renewal is 57% greater than the historical average. E.L.K. intends to have a more consistent spend within System Renewal activities, as evidenced in Figure 5.4-3, which will allow E.L.K. to manage the system's health and performance more effectively.

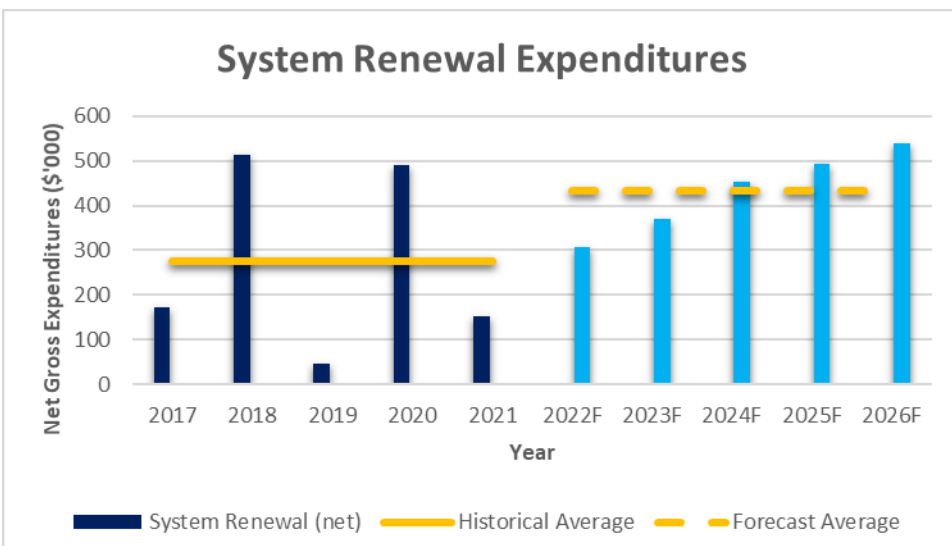


Figure 5.4-3: System Renewal Comparative Expenditures

\

System Service

E.L.K. has not conducted System Service previously under a capital program and has historically not requested System Service within their previous DSP applications. However, enhancements to the fault indicator detection capabilities on E.L.K. lines have been included in the scope of this COS from 2022 to 2026 and E.L.K. anticipates its first spend for a System Service program. The fault circuit indicators will be piloted in the Kingsville area in 2022, with plans for deployment of 10 set per year in each year of the COS application.

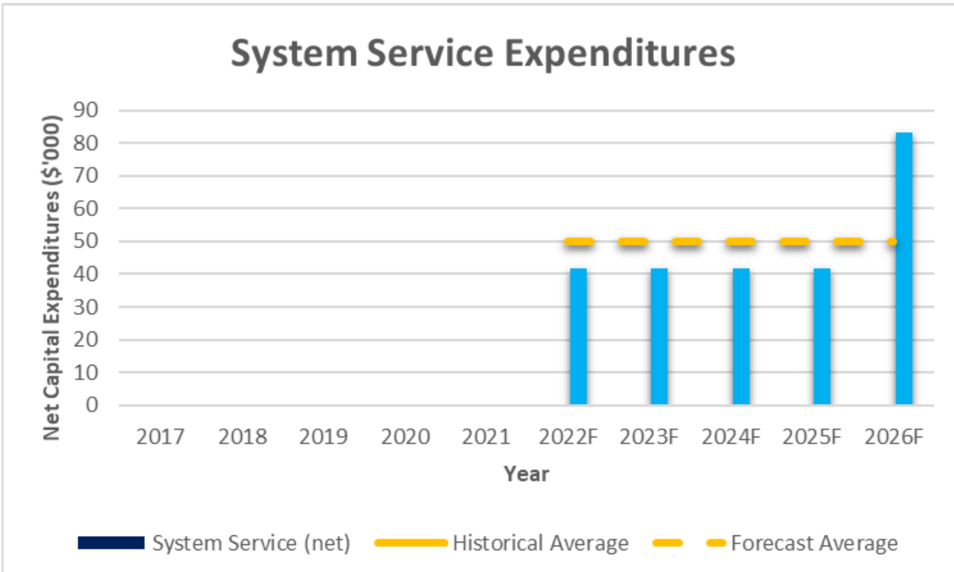


Figure 5.4-4: System Service Comparative Expenditures

General Plant

E.L.K. continues to use its framework to address critical issues needed within the General Plant program, including existing facilities, fleet, and IT assets. As shown in Figure 5.4-5, the forecast average is 24% greater than the historical period. In the historical period there were a significant number of vehicle and fleet renewals that occurred during failures within the fleet. This has resulted in General Plant capital expenditures being higher in the first two years of this COS. The increase in 2022 and 2023 is for the purchase of two large fleet vehicles to replace end of life fleet assets. The General Plant expenditures are then forecast to drop below historical levels from 2024-2026 after the purchase of the new vehicles. The justification for which is expanded upon further in Appendix X ("Fleet Vehicle Material Narrative").

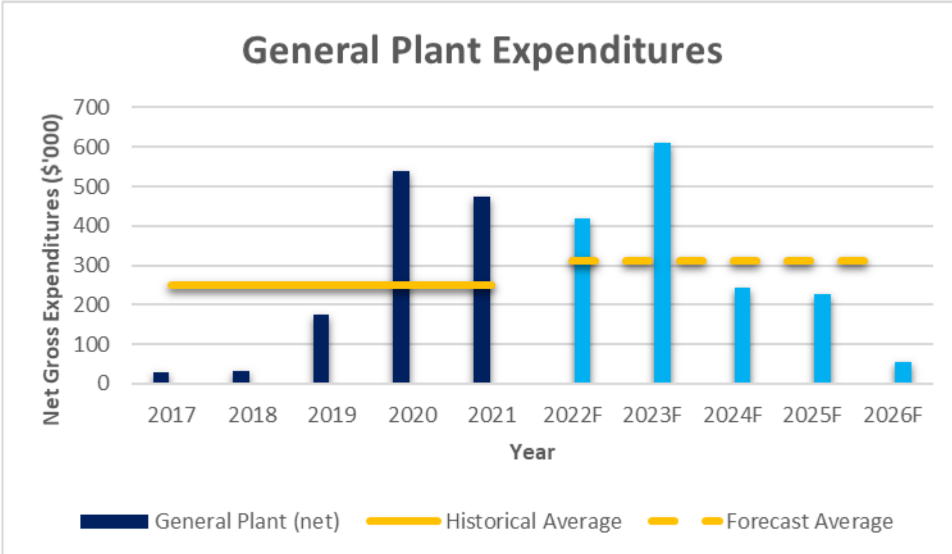


Figure 5.4-5: General Plant Comparative Expenditures

5.4.3.1.2 Forecast Impact of System Investment on System O&M Costs

While it is difficult to quantify specific system investments that directly impact system O&M costs, E.L.K. recognizes the importance and impact of prudent asset management and capital expenditure planning for the long-term ability to manage O&M costs. In particular, the new investments made in System Service for increased visibility on fault indicators can reduce restoration timelines and unnecessary field expenditures contributing to higher O&M. The General Plant investments in the GIS system and outage map will be supported by the fault indicators located in the field resulting in more efficient management of outage restoration activities. With these investments in mind, E.L.K. intends to minimize year-over-year changes to O&M costs.

A list of examples is provided below to help demonstrate commitment and consideration taken on the reduction of O&M related costs during the asset management and capital expenditure planning process.

- Proactive pole replacement as identified in the pole assessment plan and treatment prior to failure of the in-service pole or associated components will reduce costs associated with outage response and reactive replacement.
- The replacement programs allow for replacement of legacy units that can no longer be economically maintained, specifically for transformers in “poor” or “very poor” condition that were identified in the asset condition assessment.
- Investments made in new fleet vehicles will ensure long life span and are anticipated to reduce fleet maintenance costs once in service.
- Devices such as portable computing devices and the use of web-based applications to replace paper-based data collection and processes will improve operational efficiency,

reduce the possibility of data translation errors, and provide cost savings at the time of collection, and the time of data entry. Improved data is used to optimize the planning process for future projects.

5.4.3.1.3 Drivers of Investments by Category

E.L.K. has defined investment drivers for each category applicable to this DSP application.

System Access

System Access investments include the following drivers:

- Customer service requests - include developments driven by customer need or activities in the six service areas that E.L.K. operates, including new customer connections for site redevelopment, subdivisions, retail and commercial space.

System Renewal

System Renewal investments include the following drivers:

- Asset Failure Risk – through asset condition assessment, E.L.K. takes an analytical approach to identify weak spots and areas within the E.L.K. system that could be identified as in “poor” or “very poor” condition. As E.L.K.’s infrastructure continues to age the forecast trend in failure risk through asset condition assessments is anticipated to increase
- Emergency Needs – emergency reactive replacement or maintenance acts a key driver for distribution system assets requiring System Renewal.

System Service

System Service investments could include the following drivers:

- System operational objectives – real time data collection and system monitoring capabilities and investments to maintain system reliability.

General Plant

General Plant investments include the following drivers:

- System Maintenance Support – this driver includes the tools, equipment and fleet units that support maintenance activities undertaken for System Renewal. Replacement of fleet units tends to high an infrequent but high capital cost compared to the replacement of smaller support tools and equipment
- Business Operations efficiency – this driver includes efforts to streamline operations, including IT software, computer upgrades, GIS and reliability systems, and collection of data to better inform capital investment decision.

5.4.3.1.4 Information Related to the Distributor's System Capability Assessment

As outlined in Sections 5.4.3 and 5.4.1.1, E.L.K.'s distribution system is capable of meeting future demands with respect to load and generation needs. E.L.K. has not included any investments for the accommodation of REG type projects in the DSP.

5.4.3.2 Material Investments

The focus of this section is on projects/activities that meet the materiality threshold set out in Chapter 2 of the Filing Requirements.

Table 5.4-8: Project Costs

Category	Project Name	2022 Test Year Net Costs ($ '000)
System Access	SA-1: Subdivisions	$183
	SA-2: Road Relocations	$138
System Renewal	SR-1: Pole Replacement Program	$103
	SR-2: Transformer Replacement Program	$95
General Plant	GP-1: Fleet Replacement Program	$370
Total		**$889**

APPENDIX A – 2020 ASSET CONDITION ASSESSMENT

E. L. K. Energy Inc
2020 Asset Condition Assessment

Kinectrics Report: K-814217-RA-0001-R00

October 21, 2020

Kinectrics Inc.
800 Kipling Avenue
Toronto, ON
M8Z 6C4 Canada
www.kinectrics.com

DISCLAIMER

KINECTRICS INC., FOR ITSELF, ITS SUBSIDIARY CORPORATIONS, AND ANY PERSON ACTING ON BEHALF OF THEM, DISCLAIMS ANY WARRANTY OR REPRESENTATION WHATSOEVER IN CONNECTION WITH THIS REPORT OR THE INFORMATION CONTAINED THEREIN, WHETHER EXPRESS, IMPLIED, STATUTORY OR OTHERWISE, INCLUDING WITHOUT LIMITATION ANY WARRANTY OF MERCHANTABILITY OR FITNESS FOR A PARTICULAR PURPOSE, AND DISCLAIMS ASSUMPTION OF ANY LEGAL LIABILITY WHATSOEVER (INCLUDING ANY CONSEQUENTIAL DAMAGES) RESULTING FROM THE SELECTION, USE, OR THE RESULTS OF SUCH USE OF THIS REPORT BY ANY THIRD PARTY OTHER THAN THE PARTY FOR WHOM THIS REPORT WAS PREPARED AND TO WHOM IT IS ADDRESSED.

E. L. K. ENERGY INC
2020 ASSET CONDITION ASSESSMENT

Kinectrics Report: K-814217-RA-0001-R00

October 21, 2020

Prepared by:

Fan Wang
2020.10.21
12:51:51 -04'00'

Fan Wang Ph. D. P. Eng.
Senior Engineer/Scientist

Reviewed and Approved by:

Digitally signed by Yury Tsimberg
Date: 2020.10.21
13:27:55 -04'00'

Yury Tsimberg M. Eng. P. Eng.
Director – Asset Management

Dated: 2020-10-21

To: E. L. K. Energy Inc
172 Forest Avenue
Essex, ON N8M 3E4

Revision History

Revision Number	Date	Comments	Approved
R00	2020-06-30	Draft	
	2020-10-21	Final	

EXECUTIVE SUMMARY

In 2020 E. L. K. Energy Inc (ELK) determined a need to perform a condition assessment of its key distribution assets. ELK selected and engaged Kinectrics Inc. (Kinectrics) to assist with this work. This report presents the results of 2020 Asset Condition Assessment (ACA) study, and is based on the available condition data as of the end of December 2019.

Asset Categories Considered

The asset groups included in the 2020 ACA are as follows, including 6 categories or 8 sub-categories:

- Pole Mounted Transformers
- Pad Mounted Transformers
- Overhead Switches
- Pad Mounted Switchgear
- Underground Cables

For each asset category, available data were assessed, Health Index distribution was determined, and condition-based Flagged for Action plan was developed.

Overall Health Index Distribution

In general, Pole Mounted Transformers, Overhead Switches and Underground Cables had over 80% of their units classified as “good” or “very good”, and all these 3 categories had an average Health Index score of greater than 80%.

With respect to the asset categories of concern, Pad Mounted Switchgear had half of its units classified as “very poor”, with an average Health Index of 61%. As this asset group had only 2 units in total, this represented only 1 unit in “very poor” condition.

Flagged for Action Plans

Pad Mounted Transformers showed major backlog in terms of flagged for action numbers in the first year. All other categories either had no unit flagged for action, or had their flagged for action plans showing little variations throughout the next 10 years

In the short term, it was determined that Pad Mounted Transformers had the highest percentage of units flagged for action in first year, being 5.9% of population.

Furthermore, within the next 10 years, over 30% of Pad Mounted Transformers and Pad Mounted Switchgear are expected to require some action to be taken to address their condition.

The actual replacement plans might be only a subset of the Flagged for Action plans after ELK's review based on ELK's maintenance and replacement strategy.

Data Availability

All the asset groups in this study had age information only.

Recommendations

For the purpose of improving ACA study in the future, it is recommended that ELK enhance data collection in the following areas:

- Collection of inspection and maintenance data for all the asset gtoups.
- Acquisition of loading data for all the transformers.
- Historic records of asset removal for all the asset groups, for the purpose of developing ELK specific asset degradation curves in the future.

The results presented in this study are based solely on asset condition as determined by available data. Note that there are numerous other considerations that may influence ELK's planning process. Among these are obsolescence, system growth, corporate priorities, technological advancements, etc.

DEFINITIONS

Terminology	Acronym	Definition
Age Limiter	AL	The final HI assigned to an individual asset may also be limited by the asset's age. The AL is generally equal to the cumulative survival probability at a given age of an asset group. If the calculated HI is less than or equal to the AL, the final HI assigned is the calculated HI. Otherwise, the final HI assigned is equal to the AL.
Asset Condition Assessment	ACA	Process of using asset information to determine the condition of assets. Condition data can include nameplate information, test results, asset inspection records, corrective maintenance records, operational experience, etc.
Condition Parameter Score	CPS	Score of an asset for a particular condition parameter. In this study, the scoring system used ranges from 0 through 4 (0 = worst; 4 = best).
Condition Parameters	CP	Asset characteristics or properties that are used to derive the HI.
Criticality Index	CI	Index used to determine asset Criticality. CI ranges from 0% to 100%, with 100% representing the unit with the highest possible consequence of failure.
Cumulative Distribution Function	CDF	Cumulative distribution function. Assumed in this methodology as the Weibull function representing the cumulative likelihood of removals.
Data Availability Indicator	DAI	A measure of the amount of condition parameter data that an asset has, as measured against the full data sets that are practically available and included in the HI formula. It is determined by the weighted ratio of the condition parameters availability of an individual unit, over the maximum condition parameters availability of an asset group.

Terminology	Acronym	Definition
Data Gap		A data gap is the case where none of the units in an asset group has data for a particular item as requested by "ideal" data sets. A data gap means the data is either unavailable or not in a useable format.
De-rating Multiplier	DR	Multipliers used to adjust a condition or sub-condition parameter score or calculated Health Index so as to reflect certain conditions.
Flagged for Action Plan	FFA Plan	Number of units that are expected to require attention annually.
Flagged for Action Year	FFA Year	The year that a particular unit is flagged for action.
Health Index	HI	Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the factors that cumulatively lead to an asset's end of life. HI is given in terms of a percentage range of 0%-100%, with 100% representing as new condition.
Probability Density Function	PDF	Probability density function. Assumed in this methodology as the Weibull function representing the likelihood that an asset will be removed from service when its age is within a particular range.
Removal Rate		Weibull hazard function. Assumed in this methodology as the rate of removal (removals per year for given age, including failures, proactively replaced, removal for non-condition reasons).
Sample Size		Subset of an asset population with enough data (i.e. age or condition data) to calculate the HI.
Sub-Condition Parameter Score	SCPS	Score of an asset for a particular sub condition parameter. In this study, the scoring system used ranges from 0 through 4 (0 = worst; 4 = best).
Sub-Condition Parameters	CP	Asset characteristics or properties that are used to derive the HI. Each condition parameter can be comprised of multiple sub-condition parameters.
Weibull Distribution		Continuous function used, in this methodology to model, the removal rates of assets.

Terminology	Acronym	Definition
Weight of Condition Parameter	WCP	In the HI formula, condition parameters are assigned a weight that is based on t he degree of contribution or relevance to asset degradation.
Weight of Sub-Condition Parameter	WSCP	In the HI formula, condition parameters are assigned a weight that is based on t he degree of contribution or relevance to asset degradation.

This page is intentionally left blank.

TABLE OF CONTENTS

TABLE OF FIGURES

This page is intentionally left blank.

TABLE OF TABLES

This page is intentionally left blank.

I INTRODUCTION

E. L. K. Energy Inc (ELK) engaged Kinectrics Inc (Kinectrics) in 2020 to perform an Asset Condition Assessment (ACA) on selected distribution assets. An assessment produces a quantifiable evaluation of asset condition and also aids in prioritizing and allocating sustainment investments. This undertaking, if done continuously over time, would allow ELK to monitor trends in the condition of its assets and to continuously improve its assessment process and asset management practices. This assessment covered ELK's asset population as of December 2019. This report presents results based on the available data. Year 0 shown in all figures is for 2021, year 1 for 2022, year 2 for 2023 etc.

I.1 Objective and Scope of Work

The categories and sub-categories of assets considered in this study are as follows:

- Pole Mounted Transformers
- Pad Mounted Transformers
- Overhead Switches
- Pad Mounted Switchgear
- Underground Cables

I.2 Deliverables

The deliverable in this study is a Report that includes the following information:

- Description of the Asset Condition Assessment methodology
- For each asset category the following were included:
    - Health Index formulation
    - Age distribution
    - Health Index distribution
    - Condition-based Flagged For Action Plan
    - Assessment of data availability and a Data Gap analysis

This page is intentionally left blank.

II ASSET CONDITION ASSESSMENT METHODOLOGY

The Asset Condition Assessment (ACA) Methodology involves the process of determining asset Health Index, as well as developing a condition-based Flagged for Action Plan for each asset group. The methods used are described in the subsequent sections.

II.1 Health Index

Health Indexing quantifies equipment condition based on numerous condition parameters that are related to the degradation factors that lead to an asset's end of service life. The Health Index is an indicator of the asset's overall health and is typically given in terms of percentage, with 100% representing an asset in brand new condition. Health Indexing provides a measure of long-term degradation and thus differs from defect management, whose objective is finding defects and deficiencies that need correction or remediation in order to keep an asset operating prior to reaching its end of life.

Condition parameters are the asset characteristics or properties that are used to derive the Health Index. A condition parameter may be comprised of several sub-condition parameters. For example, a parameter called "Oil Quality" may be a composite of parameters such as "Moisture", "Acid", "Interfacial Tension", "Dielectric Strength" and "Colour".

In formulating a Health Index, condition parameters are ranked, through the assignment of *weights*, based on their contribution to asset degradation. The *condition parameter score* for a particular parameter is a numeric evaluation of an asset with respect to that parameter.

Health Index (HI), which is a function of scores and weightings, is therefore given by:

$$HI = \frac{\sum_{m=1}^{\forall m} \alpha_m (CPS_m \times WCP_m)}{\sum_{m=1}^{\forall m} \alpha_m (CPS_{m.\max} \times WCP_m)} \times DR$$

Equation 0-1

where

$$CPS = \frac{\sum_{n=1}^{\forall n} \beta_n (CPF_n \times WSCP_n)}{\sum_{n=1}^{\forall n} \beta_n (WSCP_n)}$$

Equation 0-2

CPS	Condition Parameter Score
WCP	Weight of Condition Parameter
α_m	Data availability coefficient (1 if available; 0 if not available)
CPF	Sub-Condition Parameter Score
WSCP	Weight of Sub-Condition Parameter
β_n	Data availability coefficient for sub-condition parameter (1 if available; 0 if not available)
DR	De-Rating Multiplier

The scale that is used to determine an asset's score for a particular parameter is called the *condition criteria*. For this project, a condition criteria scoring system of 0 through 4 is used. A score of 0 represents the worst score while 4 represents the best score. I.e. $CPF_{max} = 4$.
De-Rating multipliers are applied to the calculated HI. These may be used to represent the impact of non-condition issues such as design or operating environment.

II.1.1 Health Index Results

As stated previously, an asset's Health Index is given as a percentage, with 100% representing "as new" condition. The Health Index is calculated only if there is sufficient condition data. The subset of the population with sufficient data is called the *sample size*. Results are generally presented in terms of number of units and as a percentage of the sample size. If the sample size is sufficiently large and the units within the sample size are sufficiently random, the results may be extrapolated for the entire population.

The Health Index distribution given for each asset group illustrates the overall condition of the asset group. Further, the results are aggregated into five categories and the categorized distribution for each asset group is given. The Health Index categories are as follows:

Very Poor	Health Index < 25%
Poor	25 ≤ Health Index < 50%
Fair	50 ≤ Health Index <70%
Good	70 ≤ Health Index <85%
Very Good	Health Index ≥ 85%

Note that for critical asset groups, such as Power Transformers, the Health Index of each individual unit is given.

II.2 **Condition Based Flagged for Action Plan**

The condition based Flagged for Action Plan outlines the number of units that are expected to require attention in the next 10 years. The numbers of units are estimated using either a *proactive* or *reactive* approach. In the proactive approach, units are considered for action prior to failure, whereas the reactive approach is based on expected failures per year.

Both approaches consider asset removal rate and probability of failure. The removal rate is estimated using the method described in the subsequent section.

II.2.1 Removal Rate and Probability of Removal

Where removal rate data is not available, a frequency of removal that grows exponentially with age provides a good model.

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in removal rate studies of multiple power system asset groups, Kinectrics has selected the Weibull equation to model the removal curves. The Weibull function has no specific characteristic shape and, as such, can model the exponentially increasing removal rate using appropriate parameters.

The Weibull removal density function is defined as:

$$f(t) = \frac{\beta t^{\beta-1}}{\alpha^{\beta}} e^{-(\frac{t}{\alpha})^{\beta}}$$

Equation 0-3

f = removal rate per unit time
t = time
α, β = constant that control the scale and shape of the curve

Depending on its application, there have been various forms derived from the original equation. Based on Kinectrics' experience in removal rate studies of multiple power system asset groups, the following variation of the removal rate formula has been adopted:

The corresponding cumulative removal distribution is therefore:

$$Q(t) = 1 - R(t) = 1 - e^{-(\frac{t}{\alpha})^{\beta}}$$

Equation 0-4

Q(t) = cumulative failure distribution
R(t) = survival function

Finally, the removal rate function (i.e. hazard function) is then:

$$\lambda(t) = \frac{f(t)}{1 - Q(t)} = \frac{\beta t^{\beta-1}}{\alpha^{\beta}}$$

Equation 0-5

λ(t) = hazard function (removals per year)

Different asset groups experience different removal rates and therefore different removal distributions. The parameters α and β are determine the shapes of these curves. For each asset group, the values of these constant parameters were selected to reflect typical useful lives for these assets.

Consider, for example, an asset class where at the ages of 40 and 75 the asset has cumulative probabilities of removal of 20% and 95% respectively. It follows that when using Equation 5, α and β are calculated as 57.503 and 4.132 respectively. The removal rate and probability of removal graphs for these parameters are as follows:

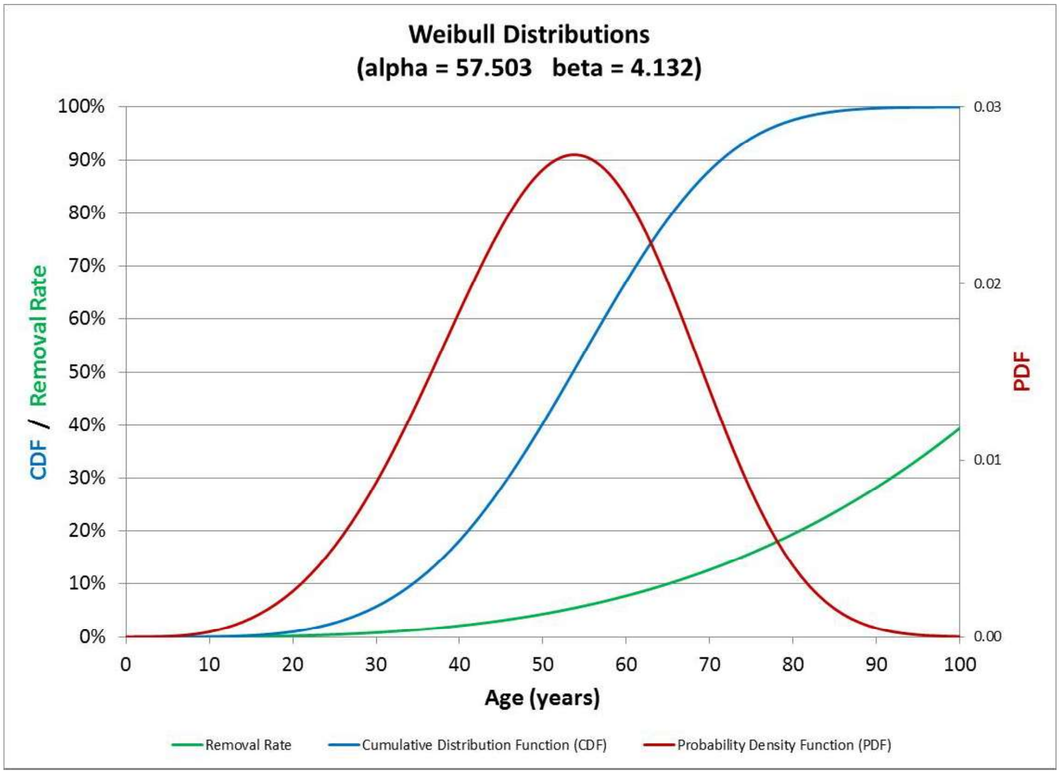


Figure 1 Removal rate vs. Age

II.2.2 Projected Flagged for Action Plan Using a Probabilistic Approach

For assets that have low consequences of failure or that are run to failure, a probabilistic approach is taken to estimate the number of units that are flagged for action in a given year.

For such asset types, the number of units expected to be replaced in a given year are determined based on the asset's removal rates. The number of failures per year is given by Equation 0-5.

An example of such a Flagged for Action Plan is as follows: Consider an asset distribution of 100 - 5 year old units, 20 – 10 year old units, and 50 - 20 year old units. Assume that the removal rates for 5, 10, and 20 year old units for this asset class are $\lambda_5 = 0.02$, $\lambda_{10} = 0.05$, $\lambda_{20} = 0.1$ failures / year respectively. In the current year, the total number of replacements is 100(.02) + 20(0.05) + 50(0.1) = 2 + 1 + 5 = 8.

In the following year, the expected asset distribution is, as a result, as follows: 8 – 1 year old units, 98 – 6 year old units, 19 – 11 year old units, and 45 - 21 year old units. The number of replacements in year 2 is therefore $8(\lambda_1) + 19(\lambda_6) + 45(\lambda_{11}) + 45(\lambda_{21})$.

Note that in this study the "age" used is in fact "effective age", or condition-based age if available, as opposed to the chronological age of the asset.

For all the asset categories in this study, the probabilistic approach is used to estimate the FFA Plan. It is also important to note that the FFA gives the estimated number of assets per year that need to be addressed; the year that a specific unit needs to be addressed is not calculated.

II.3 **Data Assessment**

The condition data used in ACA study included the following:

- Test Results (e.g. Oil Quality, DGA)
- Inspection Records
- Loading
- Make, Model, and Type
- Age

There are two components that assess the availability and quality of data used in this study: data availability indicator (DAI) and data gap.

II.3.1 Data Availability Indicator (DAI)

The Data Availability Indicator (DAI) is a measure of the amount of condition parameter data that an asset has, as measured against the full data sets that are practically available and included in the HI formula. It is determined by the weighted ratio of the condition parameters availability of an individual unit, over the maximum condition parameters availability of an asset group. The formula is given by:

$$DAI = \frac{\sum_{m=1}^{\forall m} (DAI_{CPS\,m} \times WCP_m)}{\sum_{m=1}^{\forall m} (WCP_m)}$$

Equation 6

where

$$DAI_{CPSm} = \frac{\sum_{n=1}^{\forall n} \beta_n \times WCFn}{\sum_{n=1}^{\forall n} (WCPFn)}$$

Equation 7

DAI_{CPSm}	Data Availability Indicator for Condition Parameter m with n Condition Parameter Factors (CPF)
β_n	Data availability coefficient for sub-condition parameter (=1 when data available, =0 when data unavailable)
$WSCP_n$	Weight of Condition Parameter Factor n
DAI	Overall Data Availability Indicator for the m Condition Parameters

WCP_m Weight of Condition Parameter m

For example, consider an asset with the following condition parameters and sub-condition parameters:

Condition Parameter		Condition Parameter Weight (WCP)	Sub-Condition Parameter		Sub-Condition Parameter Weight (WCF)	Data Available? (β = 1 if available; 0 if not)
m	**Name**		**n**	**Name**		
1	A	1	1	A_1	1	1
2	B	2	1	B_1	2	1
			2	B_2	4	1
			3	B_3	5	0
3	C	3	1	C_1	1	0

The Data Availability Indicator is calculated as follows:

DAI_{CP1} = (1*1) / (1) = 1
DAI_{CP2} = (1*2 + 1*4 + 0*5) / (2 + 4 + 5) = 0.545
DAI_{CP3} = (0*1) / (1) = 0

$DAI = (DAI_{CP1}*WCP_1 + DAI_{CP2}*WCP_2 + DAI_{CP3}*WCP_3) / (WCP_1 + WCP_2 + WCP_3)$
= (1*1 + 0.545*2 + 0*3) / (1 + 2 + 3)
= 35%

An asset with all available condition parameter data represented will, by definition, have a DAI value of 100%. In this case, an asset will have a DAI of 100% regardless of its Health Index score. Bear in mind that a DAI of 100% does not mean there is no data gap (to be discussed in the following section). What it really indicates is that, at the time of study, an asset has information on all the condition parameters that a utility is able to provide information for.

Provided that the condition parameters used in the Health Index formula are of good quality and there are little data gaps, there will be a high degree of confidence that the Health Index score accurately reflects the asset's condition.

II.3.2 Data Gap

The Health Index formulations developed and used in this study are based only on ELK's available data. There are additional parameters or tests that ELK may not collect but that are important indicators of the deterioration and degradation of assets. While these will not be included in the HI formula, they are referred to as data gaps. I.e. A data gap is the case where none of the units in an asset group has data for a particular item as requested by "ideal" data sets. The situation where data is provided for only a sub-set of the population is not considered as a data gap.

As part of this study, the data gaps of each asset category are identified. In addition, the data items are ranked in terms of importance. There are three priority levels, the highest being most indicative of asset degradation.

Priority	Description	Symbol
High	Impactive data; most useful as an indicator of asset degradation	☆☆☆
Medium	Important data; can indicate the need for corrective maintenance or increased monitoring	☆☆
Low	Helpful data; least indicative of asset deterioration	☆

When filling up data gaps, it is generally recommended that data collection be initiated for the items marked with higher priority, because such information will result in higher quality Health Index formulas.

The more impactive and important data included in the Health Index formula of a certain asset group, and the higher the Data Availability Indicator of a particular unit in that group, the higher the confidence in the Health Index calculated for the particular unit.

If an asset group has significant data gaps and lacks good quality condition, there is less confidence that the Health Index score of a particular unit accurately reflects its condition, regardless of the value of its DAI.

To facilitate the incorporation of data gap items into improved Health Index formulas for future assessments, the data gaps items are presented in this report as sub-condition parameters. For each item, the parent condition parameter is identified. Also given are the object or component addressed by the parameter, a description of what to assess for each component or object, and the possible source of data.

The following is an example for "Tank Corrosion" on a Pad-Mounted Transformer:

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆☆	Oil Tank	Tank surface rust or deterioration due to environmental factors	Visual Inspection

This page is intentionally left blank.

III RESULTS

This section summarizes the findings of this study.

III.1 Health Index Results

A summary of the Health Index evaluation results is shown in Table 1. For each asset category the population, sample size (number of assets with age a vaialble), average age, age availability and average DAI are given. The average Health Index and distribution are also shown. A summary of the Health Index distribution for all asset categories are also graphically shown in Figure 2. Note that the Health Index distribution percentages are extrapolated from the asset group's sample size.

It can be observed that out of the 5 categories, 3 of them had over 80% of their units classified as "good" or "very good", and all these 3 groups had an average Health Index score of greater than 80%.

It can be seen from the results that among all the asset categories, Pad Mounted Switchgear were the one of concern percentage-wise. Half of the units in these asset groups were classified as "fair", with an average Health Index score of 77%. Given the fact that there were only 2 assets in this group, this represented only 1 unit.

Table 1 Health Index Results Summary

Asset Category	Population	Sample Size	Average Health Index	Health Index Distribution: Very Poor (< 25%)	Poor (25 - <50%)	Fair (50 - <70%)	Good (70 - <85%)	Very Good (>= 85%)	Average Age	Average DAI	Age Availability
Pole Mounted Transformers	851	628	87%	6	19	37	120	446	33	Age Only	74%
Pad Mounted Transformers	818	668	85%	40	54	55	45	474	25	Age Only	82%
Overhead Switches	11	11	98%	0	0	0	0	11	29	Age Only	100%
Pad Mounted Switchgear	2	2	77%	0	0	1	0	1	19	Age Only	100%
Underground Cables (km)	124.4	113.1	99.6%	0.0	0.0	0.0	1.4	111.7	19	Age Only	91%

0% 100%

Age Only No information other than age

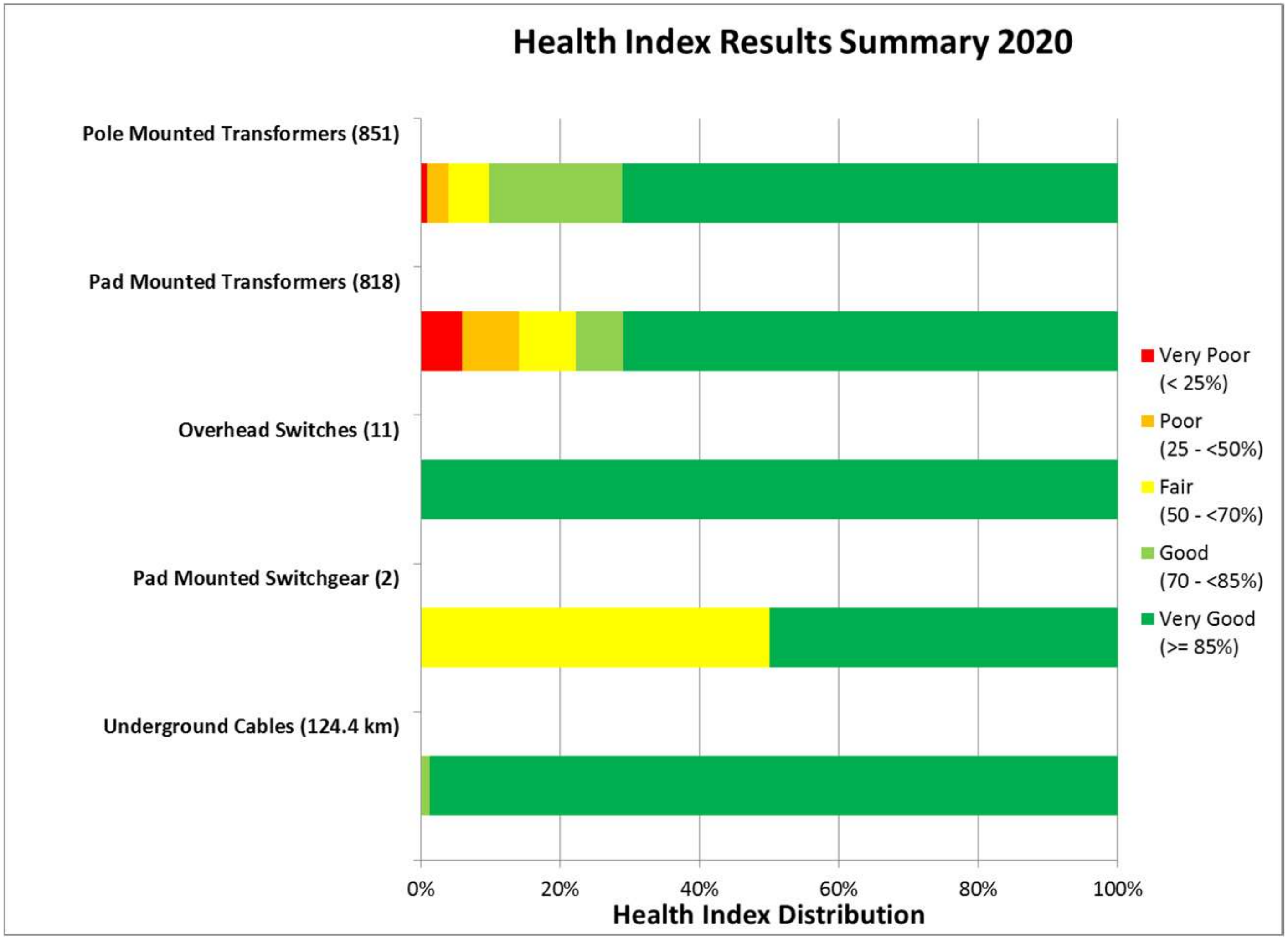


Figure 2 Health Index Results Summary

III.2 Condition-Based Flagged for Action Plan

The Flagged for Action Plan estimates the number of units expected to require attention in a given year.

Table 2 shows the Year 0 (year 2021) and 10 Year cumulative Flagged for Action Plan. Table 3 shows the 10 Year Flagged for Action Plan annually.

Table 2 Summary of Flagged for Action

Asset Category		1st Year Action		10 Year Action in Total		Replacement Strategy
		Quantity	Percentage	Quantity	Percentage	
Pole Mounted Transformers		16	1.9%	194	22.8%	Reactive
Pad Mounted Transformers		48	5.9%	269	32.9%	Reactive
Overhead Switches		0	0.0%	0	0.0%	Reactive
Pad Mounted Switchgear		0	0.0%	0	0.0%	Reactive
Underground Cables (km) (km)		0	0.0%	2.1	1.7%	Reactive

100% 0%

Table 3 Ten Year Flagged for Action Plan

Asset Category		Flagged for Action Plan by Year										
		0	1	2	3	4	5	6	7	8	9	10
Pole Mounted Transformers		16	16	18	18	20	20	20	21	22	23	23
Pad Mounted Transformers		48	42	36	30	26	22	20	17	15	13	12
Overhead Switches		0	0	0	0	0	0	0	0	0	0	0
Pad Mounted Switchgear		0	0	0	0	0	0	0	0	0	0	0
Underground Cables (km) (km)		0	0.1	0.2	0.2	0.2	0.2	0.1	0.2	0.4	0.5	0.7

* Year 0 = 2021, year 1 = 2022, year 2 = 2023 … etc

It is evident from Table 3 that in general, all the asset groups except for pad mounted transformers had failry levell flagged for action plans, indicating small variations in terms of yearly flagged for action numbers.

Pad mounted transformers show backlog in terms of flagged for action plan in the first year.

It is important to note that the Flagged for Action plan suggested in this study is based solely on asset condition. It uses a probabilistic, non-deterministic, approach and as such can only show expected failures or probable number of units that are expected to be candidates for replacement or other action. While this condition-based Flagged for Action Plan can be used as a guide or input to ELK's distribution system plan, it is not expected that it be followed directly or as the final deciding factor in making sustainment capital decisions. There are numerous other factors and considerations that will influence ELK's Asset Management decisions, such as obsolescence, system expansion, regulatory requirements, municipal demand and customer preferences etc.

III.3 Data Assessment Results

Data assessment determines the data availability for each asset group, as well as identifying the data gaps for each asset group. Data availability is a measure of the amount of data that an individual unit has in comparison with the set of data currently available in for its respective asset category.

Data gaps are items that are indicators of asset degradation, but are currently not collected or available for any asset in an asset category. The fewer the data gaps, the higher the quality of available condition data and Health Index formulas.

In this study, all the asset groups had age information only. As a consequence, data vailability index (DAI) was not applicable.

Data gap recommendation was made for each of the asset group in this study, under the section of Data Gaps of each asset group in Appendix A.

This page is intentionally left blank.

IV CONCLUSIONS

An Asset Condition Assessment was conducted for five of ELK's distribution asset categories. For each asset category, the Health Index distribution was determined and a condition-based Flagged for Action plan was developed.

The following conclusions were drawn based on the ACA findings of this study.

1) In general, 3 out 5 ELK's asset categories had over 80% of their asset units in good condition ("good" or "very good"), with all these 3 categories having an average Health Index score of greater than 80%.

2) With respect to the asset groups that were of concern percentage-wise, Pad Mounted Switchgear was found to be in the relatively speaking inferior condition, with an average Helath Index of 77%. This however addressed only 2 asset units in total for this group.

3) In terms of flagged-for-action plans, only pad mounted transformers had high backlog of units to be addressed immediately.

4) For 10-year long term flagged-for-action plans, Pad Mounted Transformers and Pad Mounted Switchgear had over 30% of the population to be addressed.

5) It is important to note that the Flagged for Action plan presented in this study is based solely on asset condition and that there are numerous other considerations that may influence ELK's Asset Management Plan, such as obsolescence, system growth, regulatory requirements, municipal initiatives, etc.

This page is intentionally left blank.

V RECOMMENDATIONS

The following recommendations were made based on the study results:

a) In the future, historic records of asset removal need to be collected for all the asset groups, so as to improve the accuracy of asset degaradtion curves.

b) Inspection records at component level need to be collected for all the asset groups, so as to improve the input granularity for better assessment of component condition status.

c) Loading data need to be collected for both Pole Mounted Transformers and Pad Mounted Transformers.

This page is intentionally left blank.

VI APPENDIX A: RESULTS FOR EACH ASSET CATEGORY

This page is intentionally left blank.

1 POLE MOUNTED TRANSFORMERS

1.1 Health Index Formula

As there was insufficient condition data available, the HI assessment for this asset category was based simply on age and the cumulative likelihood of survival at a given age.

In ideal situation where both age and condition status information is available, age is used as a limiting factor to reflect the degradation of asset unit as time passed by. The calculated overall HI result (after taking into account all the possible de-rating multipliers) is then compared with an age limiting factor.

$$Final\ overall\ HI = \begin{cases} HI_{calculated} & if\ HI_{calculated} <= Age\_Limiter \\ Age\_limiter & if\ HI_{calculated} > Age\_Limiter \end{cases}$$

The age limiting is the Weibull survival function (1 – cumulative distribution function), assuming it could be modeled by the Weibull distribution.

$$Age\_Derating = S_f = e^{-(\frac{x}{\alpha})^{\beta}}$$

Equation 6

S_f	= survivor function
x	= age in years
α	*= constant that controls scale of function*
β	*= constant that controls shape of function*

As in this case, there was no calculated HI based on condition status, the final HI would be equal to age limiting factor value.

In this project, the parameters of Pole Mounted Transformers age limiting curve are shown in the following table, based on ELK expert feedback.

Table 1-1 Age Limiting Curve Parameters - Pole Mounted Transformers

Asset Type	α	β
Pole Mounted Transformers	54.8043	4.7634

Figure 1-1 Age Limiting Factor Criteria - - Pole Mounted Transformers

1.2 Age Distribution

The average age of the units was 33 for Pole Mounted Transformers respectively.

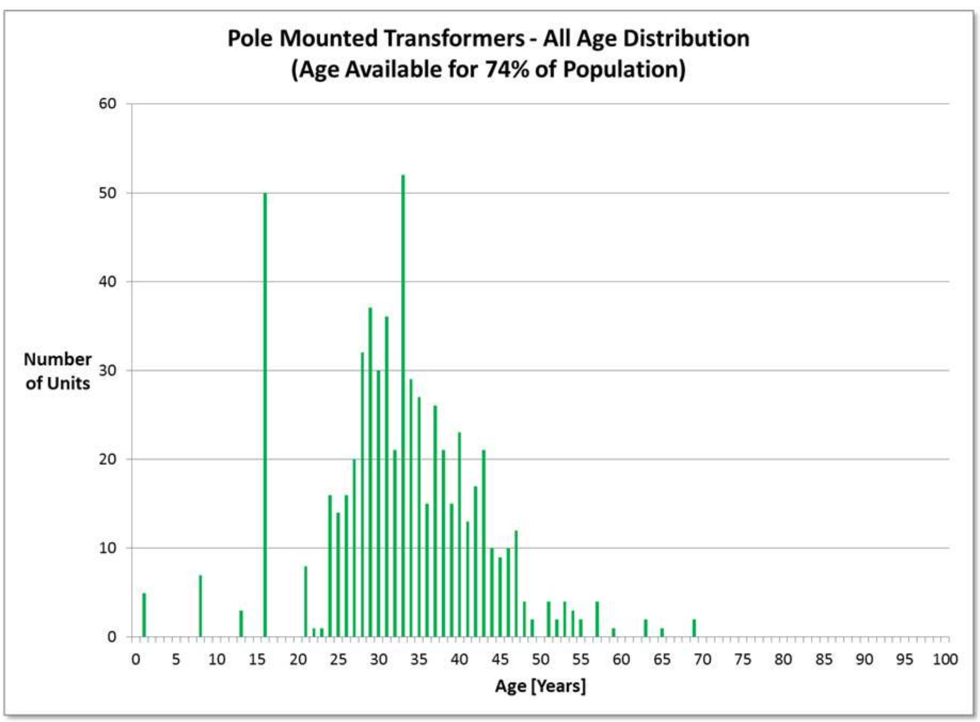


Figure 1-2 Age Distribution - Pole Mounted Transformers

1.3 Health Index Results

There were a total of 851 units of Pole Mounted Transformers. Among them, 628 units had sufficient data for a Health Indexing.

The average Health Index score was 87%, for Pole Mounted Transformers.

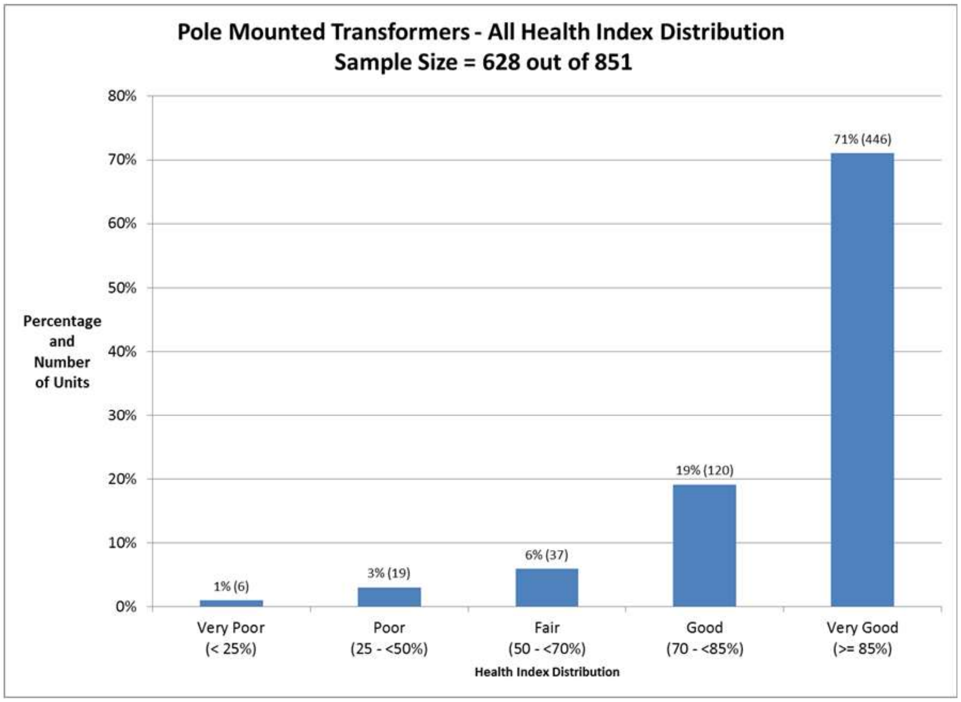


Figure 1-3 Health Index Distribution - Pole Mounted Transformers

1.4 Flagged for Action Plan

The flagged for action plan of Pole Mounted Transformers was based on the asset removal rate.

The flagged for action plans for Pole Mounted Transformers were based on the data from sample size and extrapolated to the entire population. The following diagram shows the flagged for action plans:

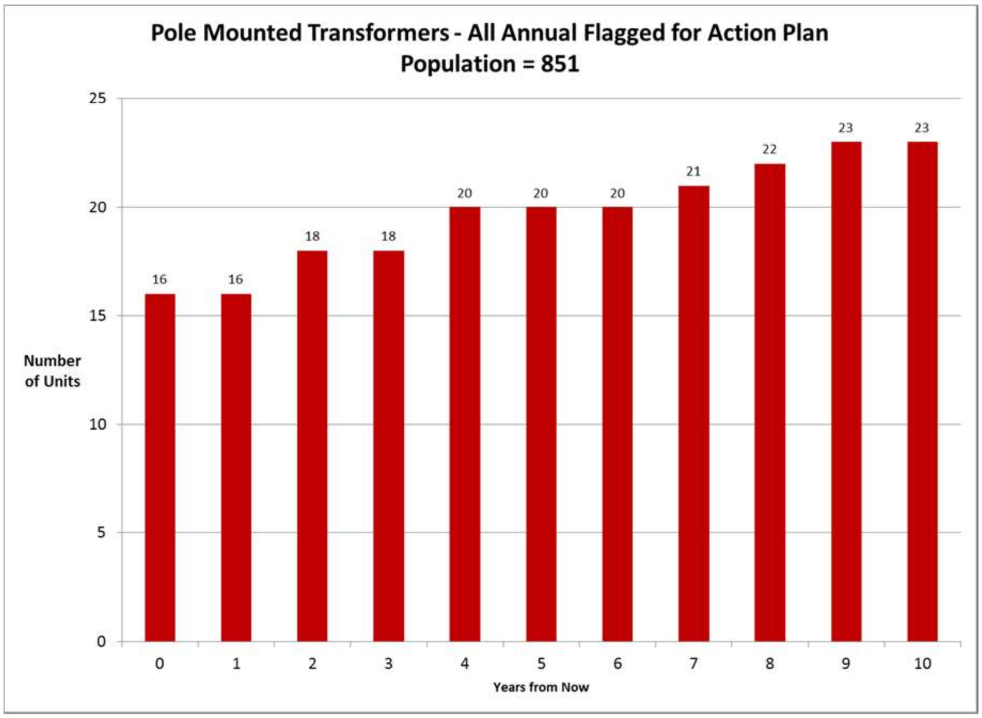


Figure 1-4 Flagged for Action Plan - Pole Mounted Transformers

1.5 Data Gaps

The data used for Pole Mounted Transformers assessment included age only.

The data gaps are as follows.

Table 1-2 Data Gap for Pole Mounted Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆	External status	Physically worn-out	On-site visual inspection
Oil Leak	Connection and Insulation Condition	☆ ☆ ☆	Transformer Oil	Leakage	On-site visual inspection
Elbow		☆ ☆	Coonection	Loose connection	
Grounding		☆	Connection	Loose connection	
Loading	Service Record	☆	Transformer load	Monthly 15 min peak load throughout years	Operation Record
Historic Removal Record		☆ ☆ ☆	Age at removal		Inventory Database

This page is intentionally left blank.

2 PAD MOUNTED TRANSFORMERS

2.1 Health Index Formula

As there was insufficient condition data available, the HI assessment for this asset category was based simply on age and the cumulative likelihood of survival at a given age.

Age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Refer to section 1.1 for principle.

In this project, the parameters of Pad Mounted Transformers age limiting curve are shown in the following table, based on ELK expert feedback.

Table 2-1 Age Limiting Curve Parameters - Pad Mounted Transformers

Asset Type	α	β
Pad Mounted Transformers	46.0252	10.6901

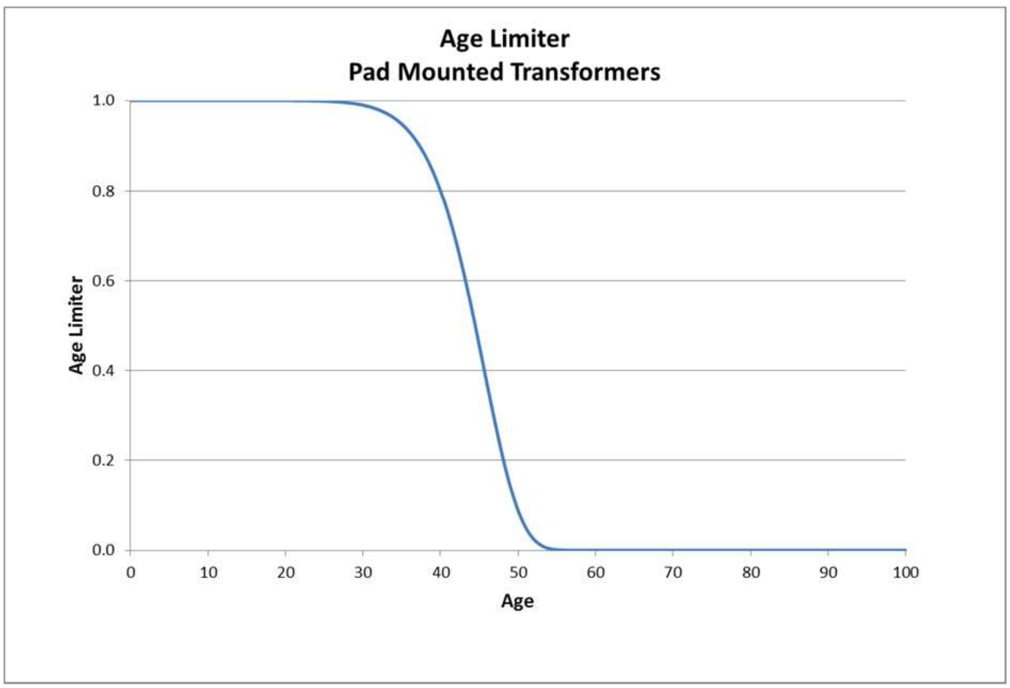


Figure 2-1 Age Limiting Factor Criteria - - Pad Mounted Transformers

2.2 Age Distribution

The average age of the units was 25 for Pad Mounted Transformers.

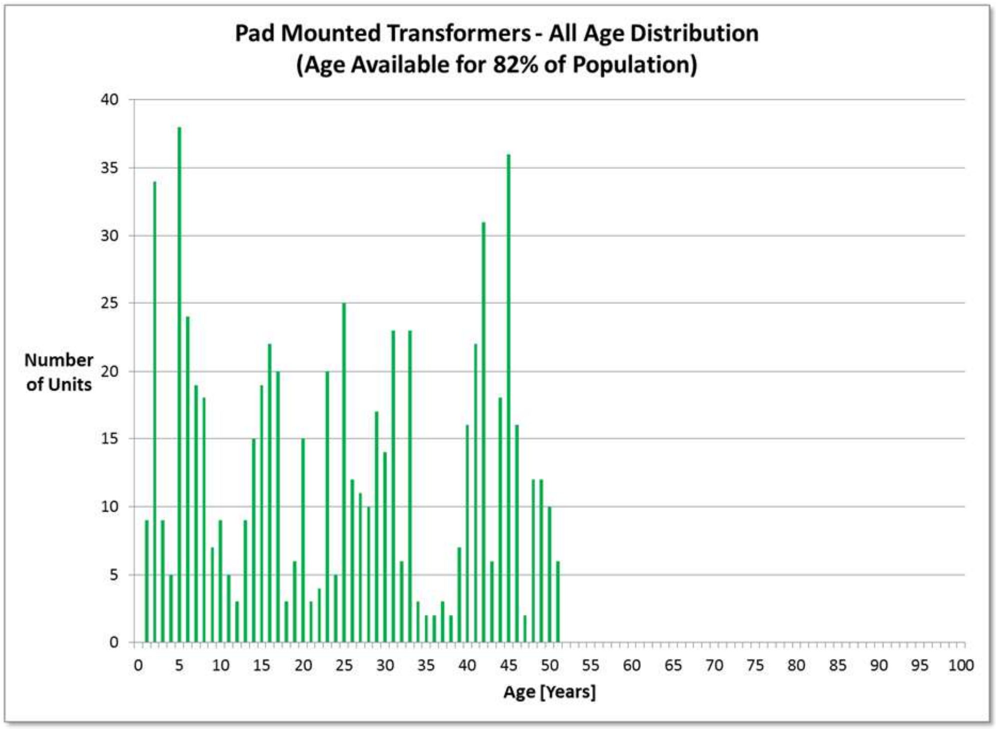


Figure 2-2 Age Distribution - Pad Mounted Transformers

2.3 Health Index Results

There were a total of 818 units of Pad Mounted Transformers. Among them, 668 units had sufficient data for a Health Indexing.

The average Health Index score for this asset group was 85% for Pad Mounted Transformers.

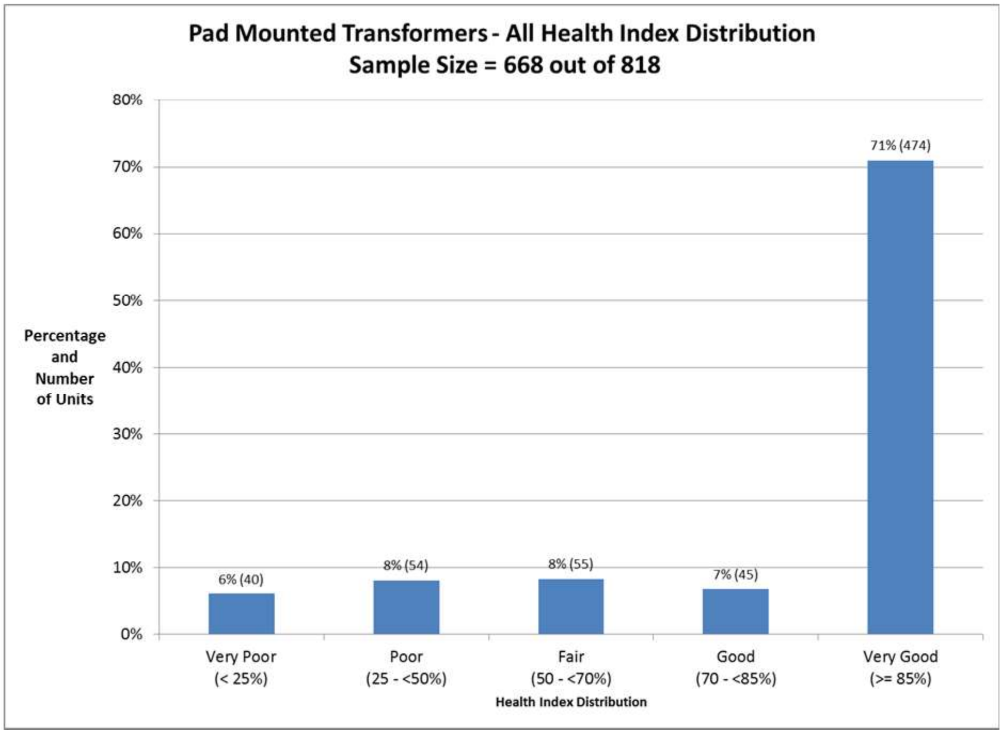


Figure 2-3 Health Index Distribution - Pad Mounted Transformers

2.4 Flagged for Action Plan

The flagged for action plan of Pad Mounted Transformers was based on the asset removal rate.

The flagged for action plans for Pad Mounted Transformers were based on the data from sample size and extrapolated to the entire population. The following diagram shows the flagged for action plans:

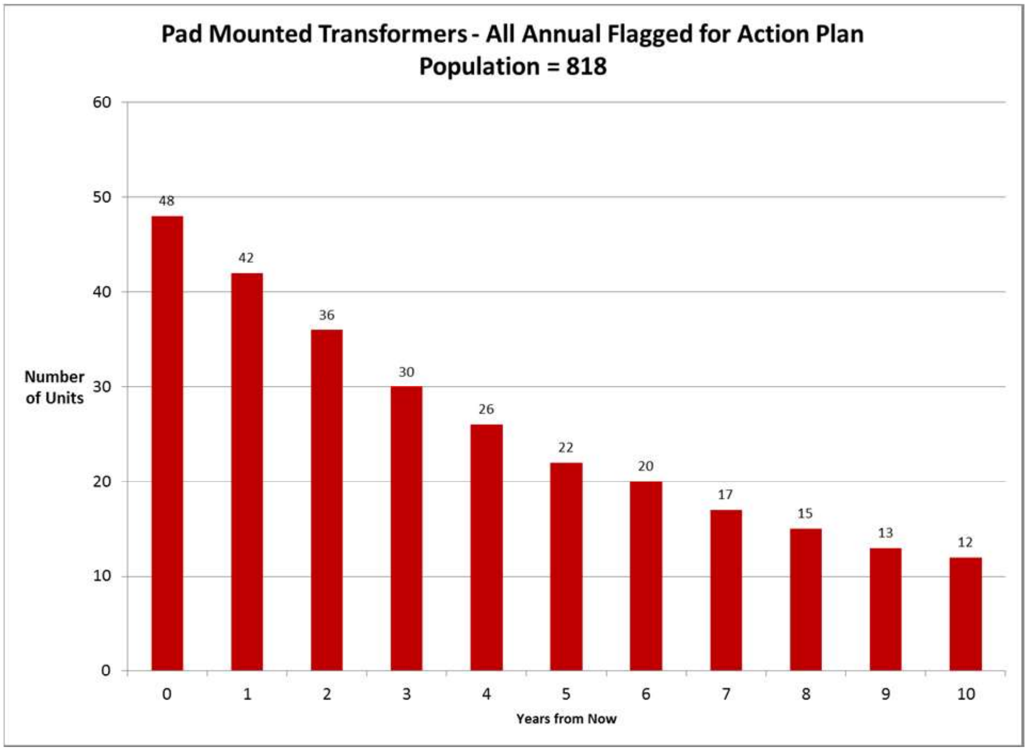


Figure 2-4 Flagged for Action Plan - Pad Mounted Transformers

2.5 Data Gaps

The data used for Pad Mounted Transformers assessment included age only.

The data gaps are as follows.

Table 2-2 Data Gap for Pad Mounted Transformers

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Tank Corrosion	Physical Condition	☆	External status	Physically worn-out	On-site visual inspection
Access		☆	Entrance	Physically locked	On-site visual inspection
Base		☆	Foundation	Physically worn-out	On-site visual inspection
Oil Leak	Connection and Insulation Condition	☆☆☆	Transformer Oil	Leakage	On-site visual inspection
Elbow		☆☆	Coonection	Loose connection	On-site visual inspection
Grounding		☆	Connection	Loose connection	On-site visual inspection
Insulator		☆☆	Insulation	Insulation Defect	Test
Gasket	Connection	☆	Gasket	Sealing issue	On-site visual inspection
Loading	Service Record	☆	Transformer load	Monthly 15 min peak load throughout years	Operation Record
Historic Removal Record		☆☆☆	Age at removal		Inventory Database

This page is intentionally left blank.

3 OVERHEAD LINE SWITCHES

3.1 Health Index Formula

As there was insufficient condition data available, the HI assessment for this asset category was based simply on age and the cumulative likelihood of survival at a given age.

Age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Refer to section 1.1 for principle.

In this project, the parameters of Overhead Line Switches age limiting curve are shown in the following table, based on industry practice.

Table 3-1 Age Limiting Curve Parameters - Overhead Line Switches

Asset Type	α	β
Overhead Line Switches	58.1804	9.8989

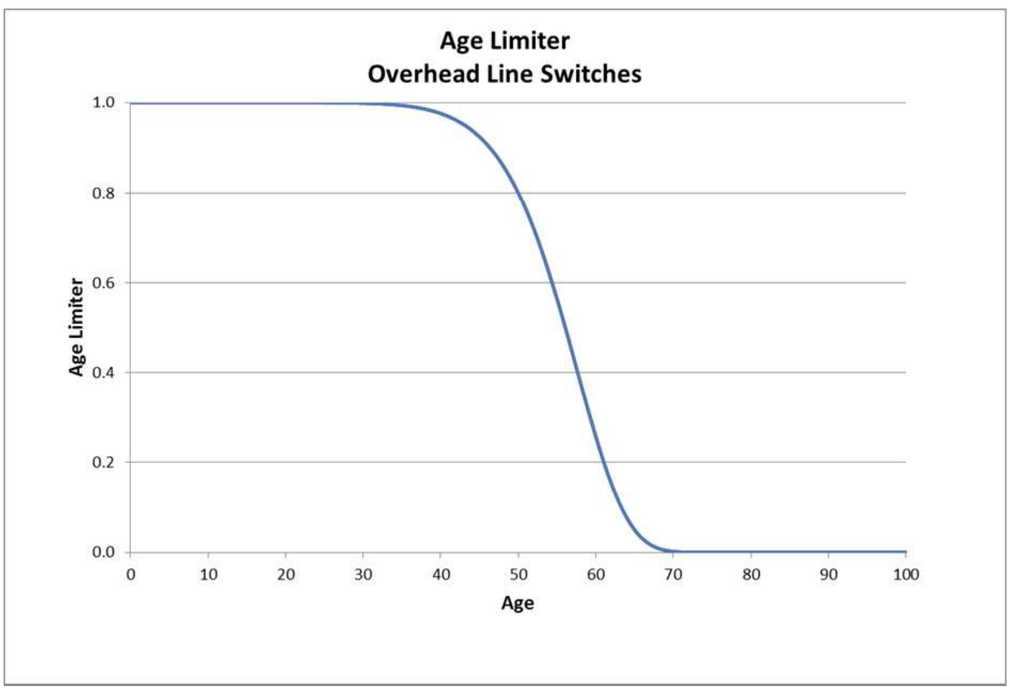


Figure 3-1 Age Limiting Factor Criteria - - Overhead Line Switches

3.2 Age Distribution

The average age of the units was 29 for Overhead Line Switches.

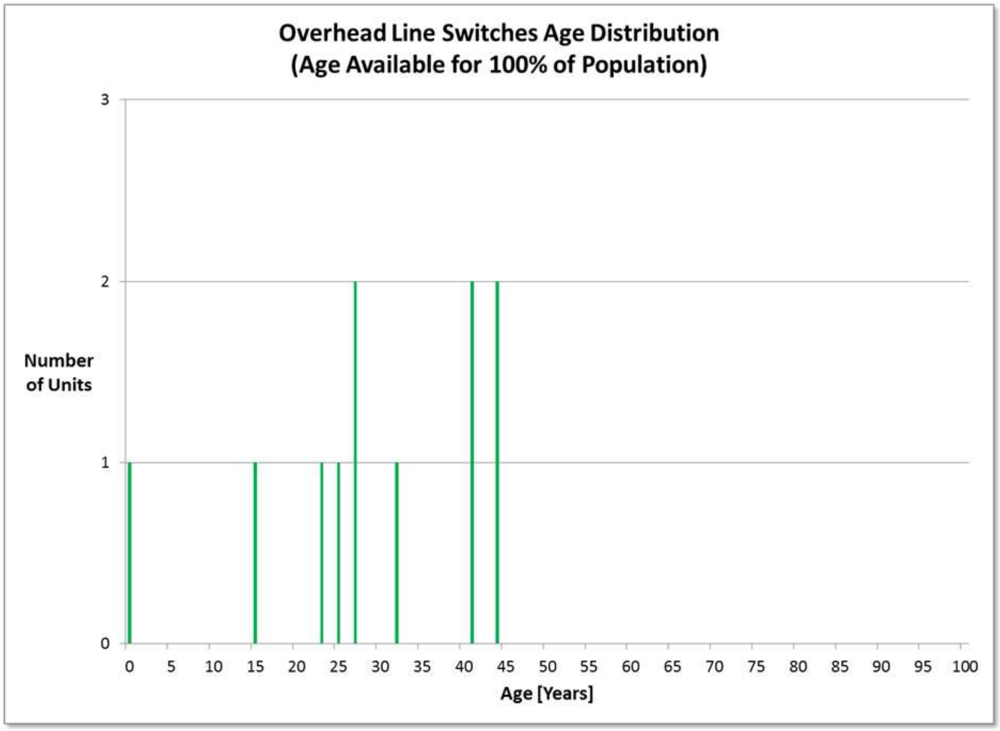


Figure 3-2 Age Distribution - Overhead Line Switches

3.3 Health Index Results

There were a total of 11 units of Overhead Line Switches. All of them had sufficient data for a Health Indexing.

The average Health Index score for this asset group was 98% for Overhead Line Switches.

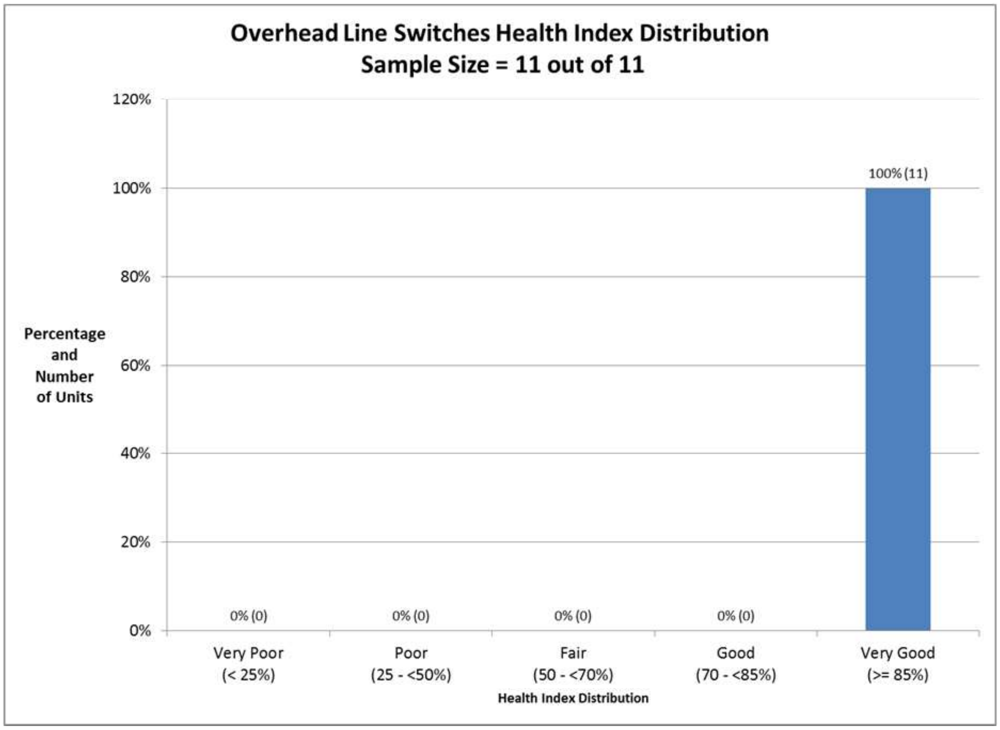


Figure 3-3 Health Index Distribution - Overhead Line Switches

3.4 Flagged for Action Plan

The flagged for action plan of Overhead Line Switches was based on the asset removal rate.

The flagged for action plans for Overhead Line Switches were based on the data from sample size and extrapolated to the entire population. Based on the existing data, there was no unit flagged for action in the coming 10 years.

3.5 Data Gaps

The data used for Overhead Line Switches assessment included age only.

The data gaps are as follows.

Table 3-2 Data Gap for Overhead Line Switches

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Description**	**Source of Data**
Motor Mechanism	Operation Mechanism	☆☆☆	Mechanical part and linkage issue	Inspection/ Maintenance Records
Load Break handle		☆☆	Mechanical part and linkage issue	
Switch Mounting		☆	Loose installation	
Arc Interrupter	Arc Extinction	☆☆☆	Arc extinction part surface worn-out	
Insulator	**Insulation**	☆	Crack	
Historic Removal Record		☆☆☆	Age at removal	Inventory Database

4 PAD MOUNTED SWITCHGEAR

4.1 Health Index Formula

As there was insufficient condition data available, the HI assessment for this asset category was based simply on age and the cumulative likelihood of survival at a given age.

Age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Refer to section 1.1 for principle.

In this project, the parameters of Pad Mounted Switchgear age limiting curve are shown in the following table, based on ELK expert feedback and industry practice.

Table 4-1 Age Limiting Curve Parameters - Pad Mounted Switchgear

Asset Type	α	β
Pad Mounted Switchgear	32.80	5.53

Figure 4-1 Age Limiting Factor Criteria - - Pad Mounted Switchgear

4.2 Age Distribution

The average age of the units was 19 for Pad Mounted Switchgear.

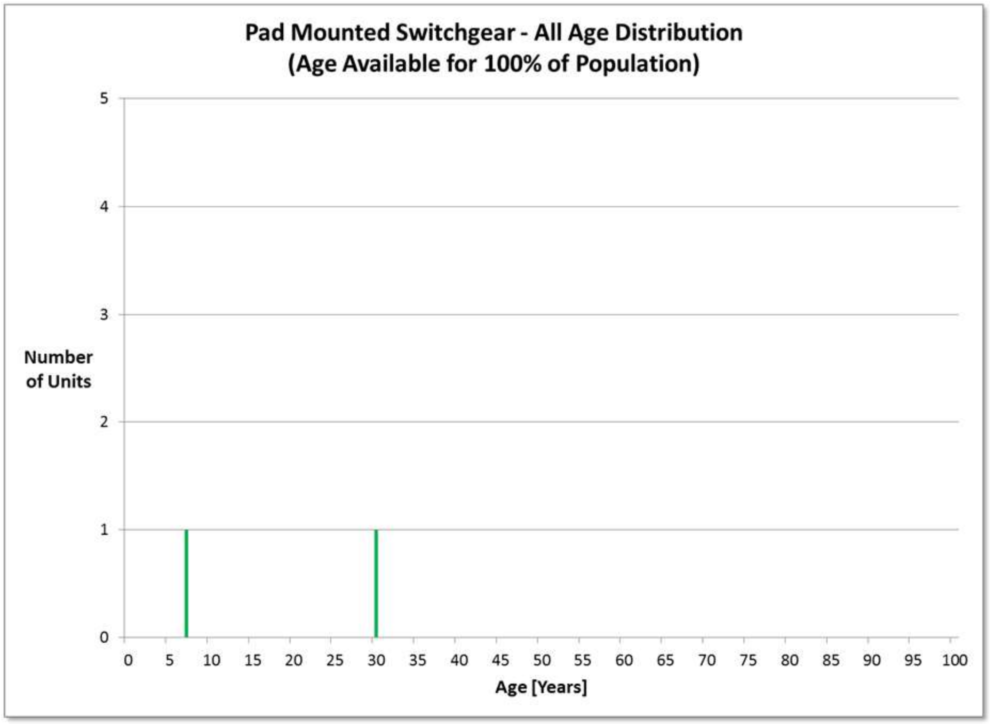


Figure 4-2 Age Distribution - Pad Mounted Switchgear

4.3 Health Index Results

There were a total of 2 units of Pad Mounted Switchgear. Both of them had sufficient data for a Health Indexing.

The average Health Index score for this asset group was 77% for Pad Mounted Switchgear.

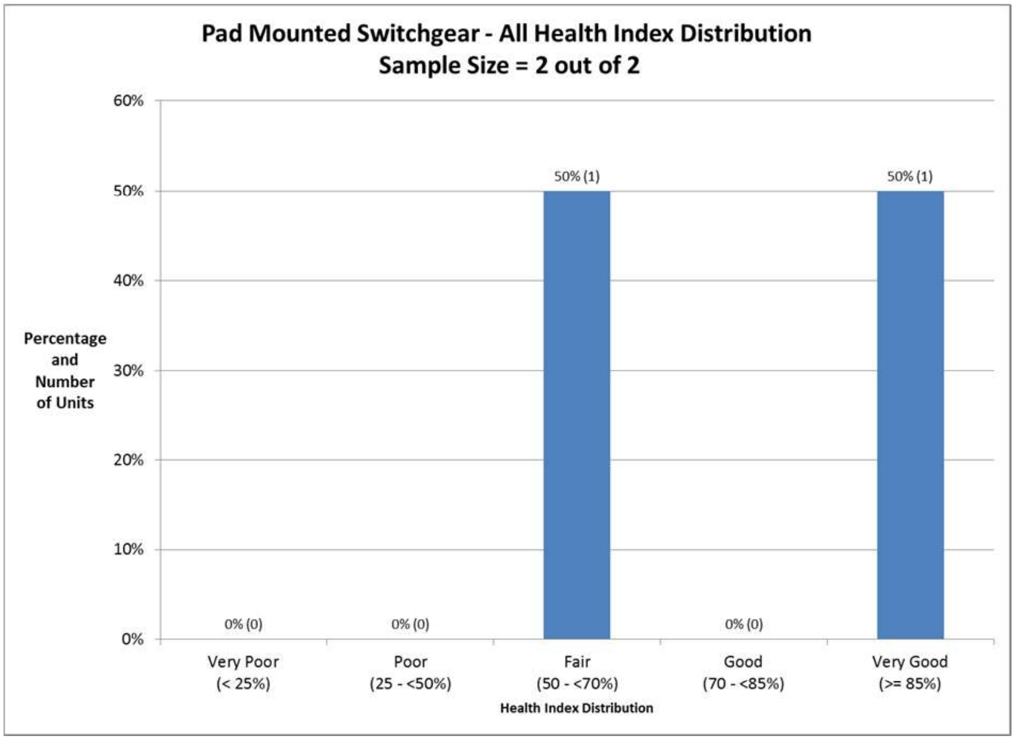


Figure 4-3 Health Index Distribution - Pad Mounted Switchgear

4.4 Flagged for Action Plan

The flagged for action plan of Pad Mounted Switchgear was based on the asset removal rate.

The flagged for action plans for Pad Mounted Switchgear were based on the data from sample size and extrapolated to the entire population. Based on the existing data, there was no unit flagged for action in the coming 10 years.

4.5 Data Gaps

The data used for Pad Mounted Switchgear assessment included age only.

The data gaps are as follows.

Table 4-2 Data Gap for Pad Mounted Switchgear

Data Gap (Sub-Condition Parameter)	**Parent Condition Parameter**	**Priority**	**Object or Component Addressed**	**Description**	**Source of Data**
Concrete Pad	Physical Condition	☆	Foundation	Physically worn-out	On-site visual inspection
Corrosion		☆ ☆	External status	Physically worn-out	On-site visual inspection
Excess Moisture		☆	Environment	Humid operating condition	On-site visual inspection
Fuse Holder	Switch/Fuse Condition	☆ ☆ ☆	Fuse	Abnormal breaking performance	On-site visual inspection
Grounding		☆	Grounding	Grounding connection	On-site visual inspection
Insulators	Insulation Condition	☆ ☆	Insulation	Insulation defect	On-site visual inspection
Barriers		☆ ☆			On-site visual inspection
Cable Terminations		☆ ☆	Cabling	Loose connection or overheating	On-site visual inspection
Connections		☆ ☆	Connection		On-site visual inspection
Historic Removal Record		☆ ☆ ☆	Age at removal		Inventory Database

This page is intentionally left blank.

5 UNDERGROUND CABLES

5.1 Health Index Formula

As there was insufficient condition data available, the HI assessment for this asset category was based simply on age and the cumulative likelihood of survival at a given age.

Age was used as a limiting factor to reflect the degradation of asset unit as time passed by. Refer to section 1.1 for principle.

In this project, the parameters of Underground Cables age limiting curve are shown in the following table, based on ELK expert feedback and industry practice.

Table 5-1 Age Limiting Curve Parameters - Underground Cables

Asset Type	α	β
Non TR Direct Buried	46.0252	10.6901
TR In Duct	70.6002	18.1489

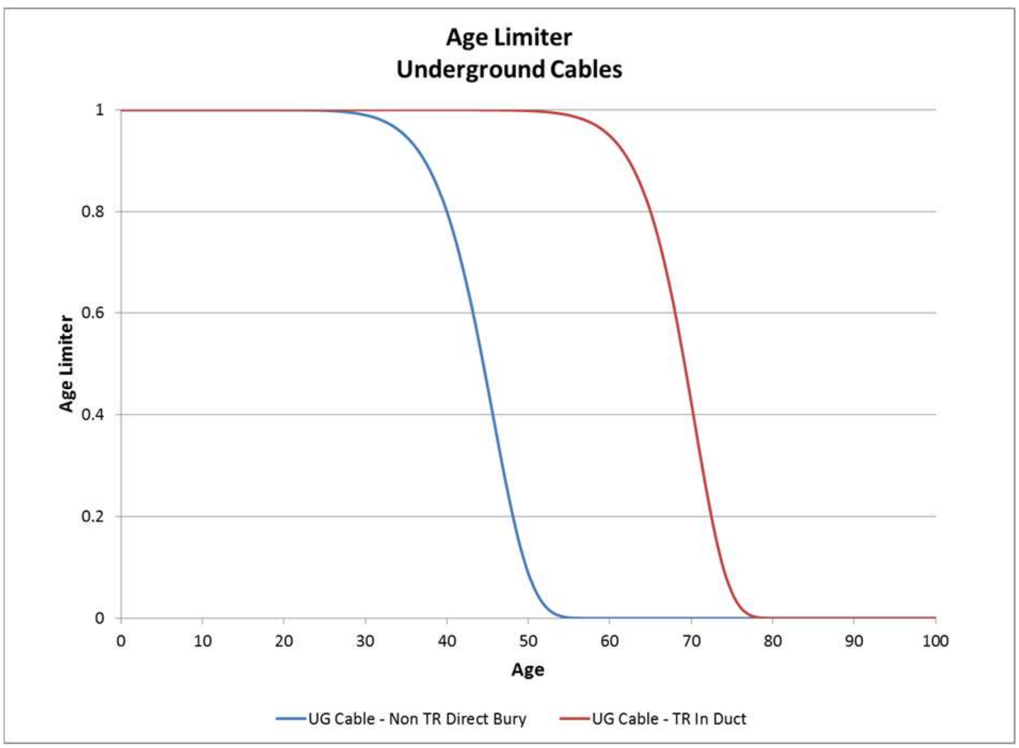


Figure 5-1 Age Limiting Factor Criteria - - Underground Cables

5.2 Age Distribution

The average age of the units was 19 for Underground Cables.

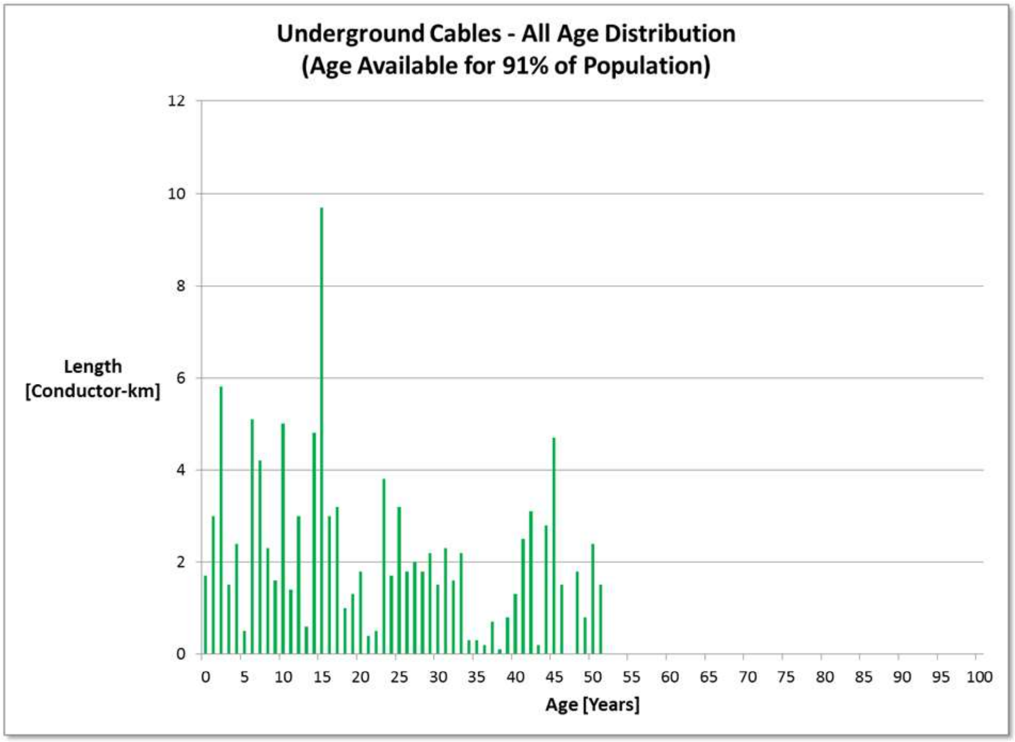


Figure 5-2 Age Distribution - Underground Cables

5.3 Health Index Results

There were a total of 124.4 conductor-km of Underground Cables. Among them, 113.1 conductor-km had sufficient data for a Health Indexing.

The average Health Index score for this asset group was 99.6% for Underground Cables.

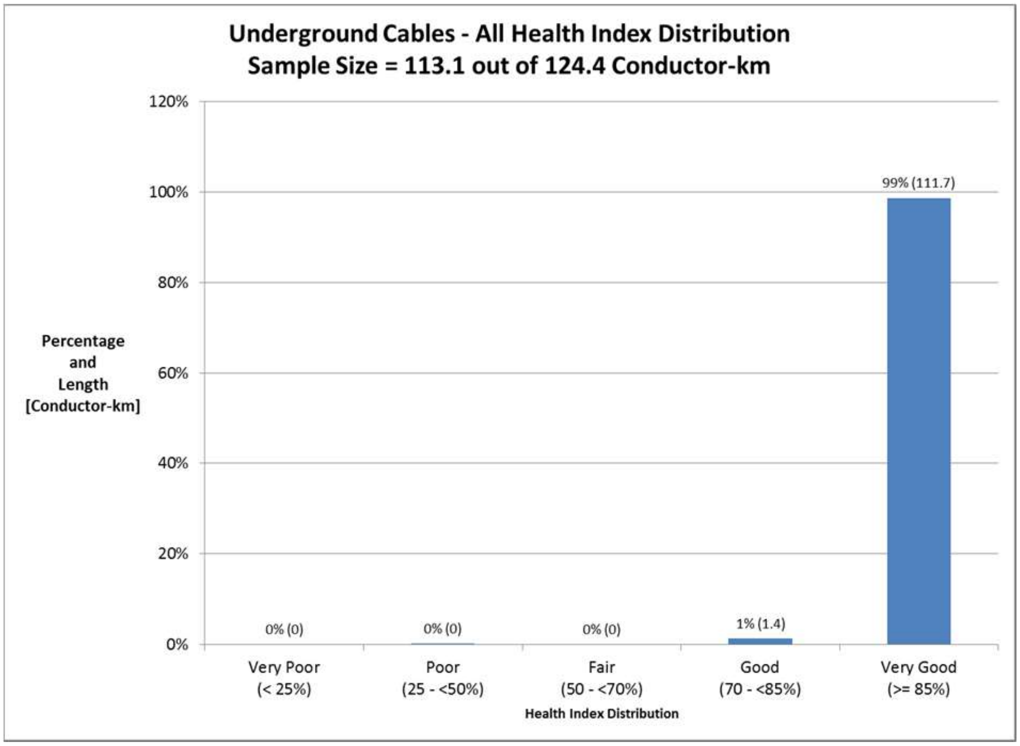


Figure 5-3 Health Index Distribution - Underground Cables

5.4 Flagged for Action Plan

The flagged for action plan of Underground Cables was based on the asset removal rate.

The flagged for action plans for Underground Cables were based on the data from sample size and extrapolated to the entire population. The following diagram shows the flagged for action plans:

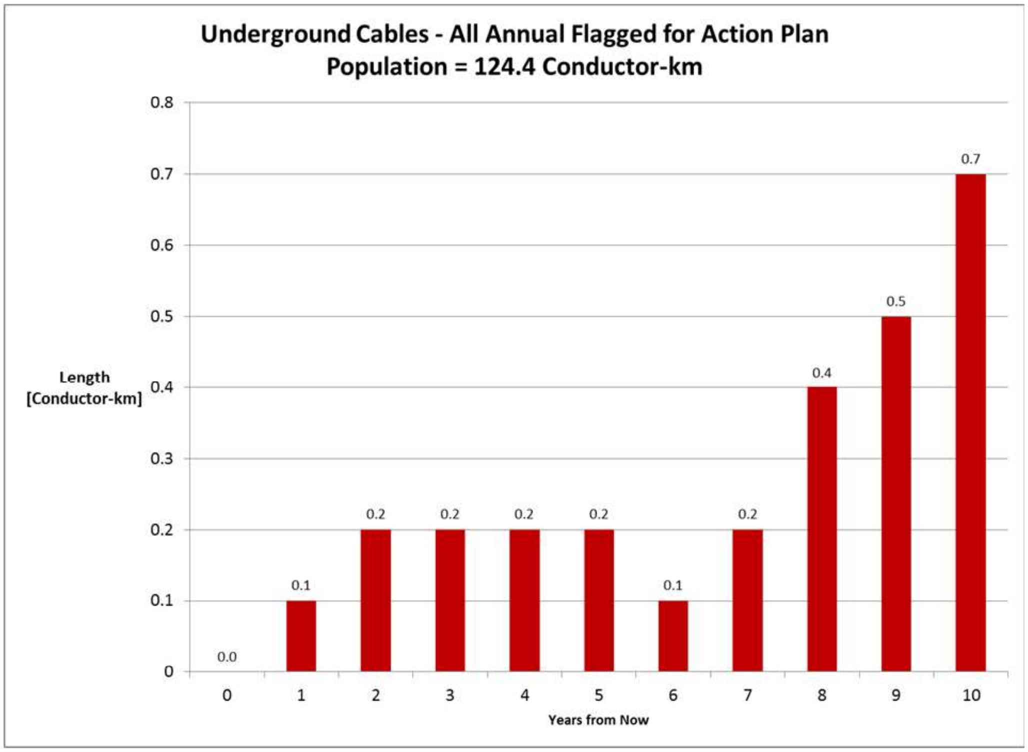


Figure 5-4 Flagged for Action Plan - Underground Cables

5.5 Data Gaps

The data used for Underground Cables assessment included age only.

The data gaps are as follows.

Table 5-2 Data Gap for Underground Cables

<table>
<tr><th>Data Gap
(Sub-Condition Parameter)</th><th>Parent Condition Parameter</th><th>Priority</th><th>Object or Component Addressed</th><th>Description</th><th>Source of Data</th></tr>
<tr><td>Dielectric Loss</td><td>Insulation</td><td>☆☆☆</td><td>Cable</td><td>Insulation defect</td><td>On-site test</td></tr>
<tr><td>Splices</td><td rowspan="3">Accessories</td><td>☆☆</td><td rowspan="2">Cable Connection</td><td rowspan="2">Connection defect</td><td rowspan="3">On-site test</td></tr>
<tr><td>Terminations</td><td>☆☆</td></tr>
<tr><td>Neutral Corrosion</td><td>☆</td><td>Other Component</td><td>Neutral defect</td></tr>
<tr><td>Fault rate at Segment Level</td><td>Service Record</td><td>☆☆☆</td><td>Cable</td><td>Failure records</td><td>Historic records</td></tr>
<tr><td colspan="2">Historic Removal Record</td><td>☆☆☆</td><td>Age</td><td>Age at Removal</td><td>Inventory Database</td></tr>
</table>

APPENDIX B – 2020 POLE INSPECTION REPORT

Report:

Pole Inspection

Submitted to:

E.L.K. Energy Inc.

Prepared by:

EDM International, Inc.

October 2020

E. L. K. Energy Inc.
Pole Inspection Report

October 21, 2020

Prepared by:

Tom Janzen
T&D Asset Management Specialist

Reviewed and Approved by:

Robert Nelson
Project Director

Dated: October 22, 2020

EXECUTIVE SUMMARY

E.L.K. Energy (ELK) has contracted Kinectrics to develop an asset management plan. EDM International, Inc. (EDM) is assisting with the development of the pole management aspect of this plan. EDM has completed an initial inspection and analysis of 294 ELK poles. The results were used to identify poles for replacement, poles that have defects but not requiring replacement at this time, and poles with no defects. There were 13 poles (4%) identified for Urgent replacement and 14 poles (5%) for medium priority mitigate or replacement. EDM has developed a longer-term plan for pole inspections based on the inspection results and analysis of those results.

EDM recommends ELK determine the condition of all their poles using inspections and data gathering. Initial inspections should focus on poles installed before 2000. EDM also recommends the development of a life-extension program for wood poles. The pole management plan should continue to be refined as more data is obtained on the performance of different species of wood used for poles and different preservative treatments in different environmental conditions. Detailed recommendations are provided in Section 3.

Table of Contents

List of Tables

List of Figures

1 BACKGROUND

E.L.K. Energy (ELK) operates and maintains more than 3,200 wood poles within the Ontario communities of Belle River, Comber, Cottam, Essex, Harrow, and Kingsville. Most of these poles were installed before 2000. The oldest pole in the sample was 58 years old. The poles are of different species and treatments which vary based on availability and changes in the industry. The performance of different species of wood is dependent on the environmental conditions, manufacturing processes, original treatment, and the individual characteristic of each pole. Individual poles may be damaged when hit by vehicles, snow removal equipment and other equipment.

2 ACTIVITIES

The following activities were performed to develop the initial pole management plan:

- Initial plan and site work preparation
- On-site testing and data collection
- Data interpretation and analyses
- Pole management program development

3 INITIAL PLAN AND SITE WORK PREPARATION

EDM performed the following tasks for the initial site work preparation:

- Imported the pole information supplied by ELK into a field inspection software (CartoPac). The information typically included installation year, pole height, pole class, and location. Installation year was known for approximately 25% of the poles.
- Researched historical information on poles in the different areas.
- Researched and compiled environmental conditions affecting pole life which will include wind strength and direction, as well as the impact of degradation mechanisms (e.g. advanced decay, insects, etc). The moderate temperatures for much of the year along with the moisture result in a moderate decay zone.
- CartoPac was configured to ensure the required information was collected to assess the poles and perform initial analysis on trends. The information gathered included

- Setting – soil, asphalt, cement
- Inspection type
- Species
- Original preservative
- Height
- Class
- Year of manufacture – obtained from pole stamp
- Ground line circumference
- Previous inspections
- Details of defects found including defect type, location on pole, size (width, height, and depth)

The priority areas to be inspected in 2020 were determined based on research and information provided by ELK. The groupings were based on operations input, pole age, treatment, size, class, and environmental area. The physical location of poles was also used as a factor. This included whether the poles were set in soil, asphalt or cement and proximity to water. Selections were refined to ensure inspections take place in all areas.

One hundred fifty-seven poles were selected using the methods noted above. The inspectors were provided with criteria to select the remaining poles. This included inspection types, pole age, pole species, and treatments. A total of 294 poles were inspected.

3.1 On Site Testing and Data Collection

The inspectors performed the testing and data gathering from September 21- 26, 2020. Inspections were performed by probing and sounding to detect internal decay, drilling into the pole at ground line near the largest check, and drilling at other locations where internal decay was suspected. The highest level where a test performed was 54 inches (1.4m). Defects above this level were noted in comments but are not quantified. If a pole was condemned by probing and sounding, an intrusive test would not be required.

Intrusive tests consisted of a minimum of three holes, 6-8 inches below ground line (the distance below ground will be increased in rocky areas), at 120 degrees apart, at an angle of 45-60 degrees from the pole. Shell thickness was measured through the inspection holes by using a shell gauge and the measurements were noted in field inspection software. Average shell thickness was determined using a minimum of three measurements on a pole. Holes were plugged using appropriately sized plastic plugs.

Poles with less than two inches shell were marked for replacement. Poles in critical condition were identified for urgent replacement or repair and the information was forwarded to ELK.

Inspection methods used were:

Inspection Description	Quantity
Visual, sound and bore	75
Visual, sound and bore, dig three divots 6-8 inches deep	140
Visual, sound and bore, dig three divots 12inches deep	74
Visual, sound and bore, dig three divots 18inches deep	5

The inspections were spread across the following years of manufacture:

Decade	Quantity
1960s	2
1970s	5
1980s	86
1990s	189
2000s	8
2010s	4
Total	**294**

The species of poles inspected was obtained from pole stamps and were as follows:

Species	Quantity
Jack pine	14
Lodgepole pine	93
Ponderosa pine	2
Red pine	86
Southern pine	64
Unknown	5
Western cedar	30
Total	**294**

The treatment of poles inspected was obtained from pole stamps and characteristics observed. The treatments found were as follows:

Original Treatment	Quantity
Copper naphthenate	42
Penta	218
Creosote	32
Unknown	2
Total	**294**

The number of poles inspected were dispersed across the different areas:

Area	Quantity
Belle River	50
Comber	33
Essex	51
Harrow	85
Kingsville	75
Total	**294**

3.2 Data Interpretation and Analyses

The information gathered from the on-site testing task was used to calculate remaining strength of each pole using D-Calc^{TM}. Poles that do not meet the Canadian Standards Association, CSA C22.3 No. 1, "Overhead Systems" clause 8.3.1.3 stating, "When the strength of a structure has deteriorated to 60 percent of the required capacity, the structure shall be reinforced or replaced," were identified for replacement/ mitigation. The results of the calculations were supplied to ELK within the electronic data file.

Remaining strength calculations and inspector observations were used to determine recommended actions. Table 3-1 shows the results of that work.

Table 3-1. Recommended actions and numbers of poles requiring each action.

Recommended Action	Quantity
Less than 25% urgent replacement	13
25-50% Mitigate/replace	14
50-70% Non-restorable	18
50-70% Restorable	23
Greater than 70% maintain	45
Pass	181
Grand Total	**294**

The geographical location of the poles inspected, and the recommended actions are depicted in Figure 3–1 through to Figure 3–6.

Symbol	Recommended Action
1	Less than 25% Urgent replacement
10	Pass
2	25-50% Mitigate or Replace
3	50-70% Non-restorable
4	50-70% Restorable
5	Greater than 70% maintain

Figure 3–1. Figure legend.

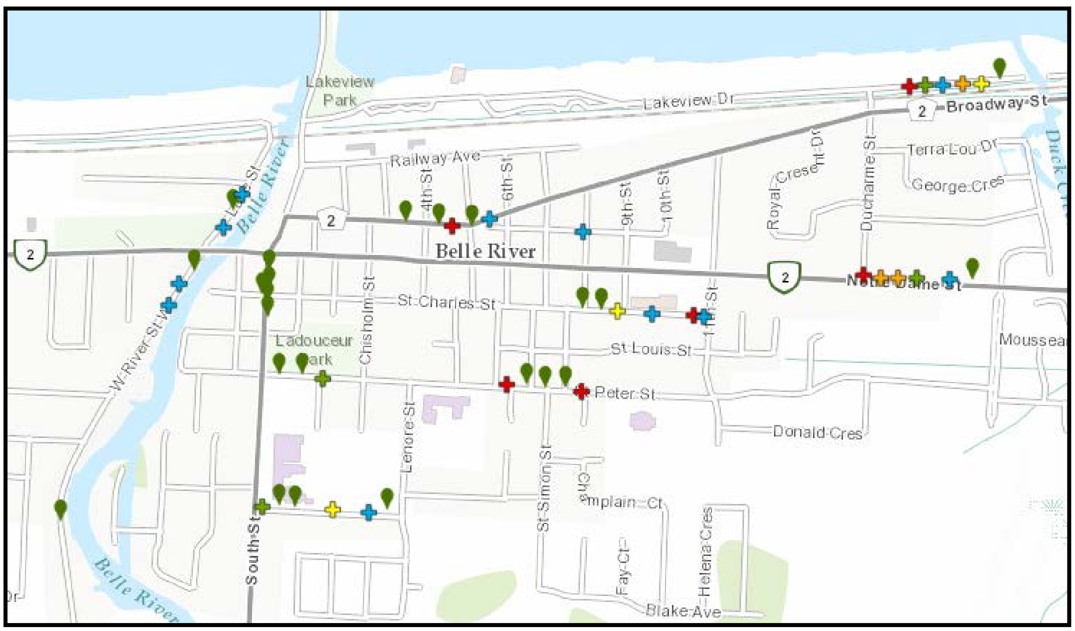


Figure 3–2. Belle River - inspected poles.

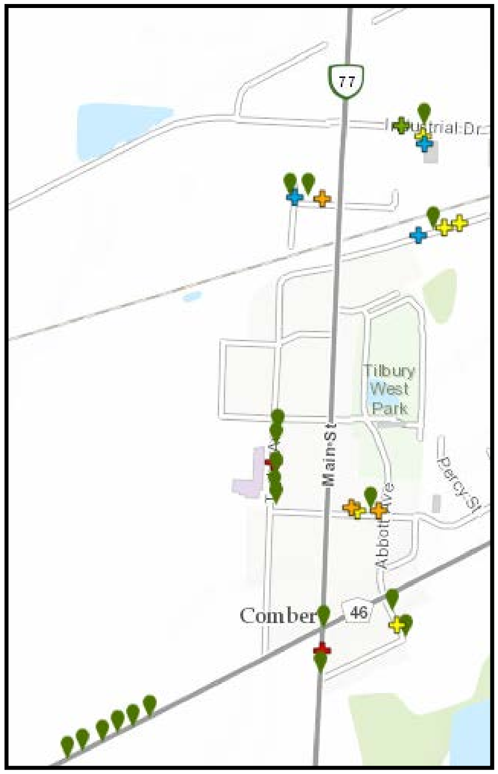


Figure 3–3. Comber - inspected poles.

Figure 3–4. Essex - inspected poles.

Figure 3–5. Harrow - inspected poles.

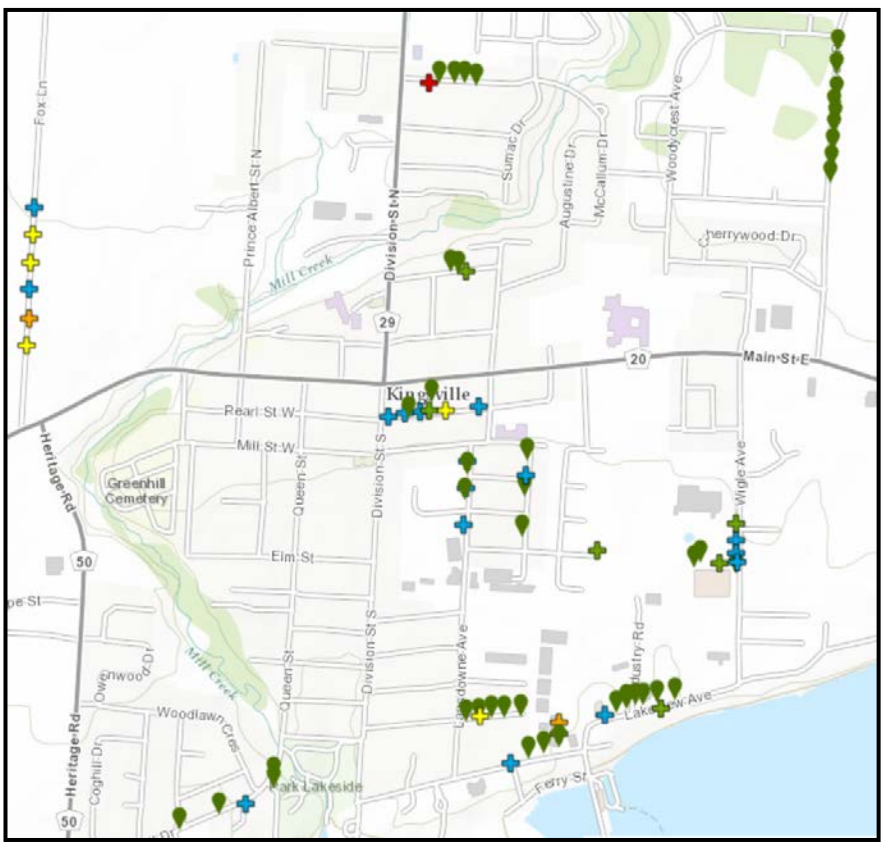


Figure 3–6. Kingsville - inspected poles.

Table 3-2 shows the percentage of each species inspected in each area compared to the total poles inspected.

Table 3-2. Comparison of species inspected.

Species	Belle River	Comber	Essex	Harrow	Kingsville
Jack pine	0%	1%	0%	2%	1%
Lodgepole pine	3%	7%	8%	6%	7%
Ponderosa pine	0%	0%	0%	0%	0%
Red pine	4%	2%	5%	10%	8%
Southern pine	3%	1%	3%	10%	6%
Unknown	1%	0%	0%	0%	0%
Western cedar	6%	0%	0%	1%	3%
Total	**17%**	**11%**	**17%**	**29%**	**26%**

Table 3-3 shows the percentage of each manufacture decade inspected in each area compared to the total poles inspected.

Table 3-3. Comparison of decade of manufacture inspected.

Decade	Belle River	Comber	Essex	Harrow	Kingsville
1960s	0%	0%	1%	0%	0%
1970s	1%	0%	0%	0%	0%
1980s	6%	4%	8%	4%	8%
1990s	10%	6%	8%	24%	16%
2000s	0%	1%	1%	1%	0%
2010s	0%	0%	0%	0%	1%
Total	**17%**	**11%**	**17%**	**29%**	**26%**

Table 3-4 shows the percentage of poles requiring replacement/ mitigation compared to total inspected in all areas.

Table 3-4. Comparison of poles requiring replacement/mitigation.

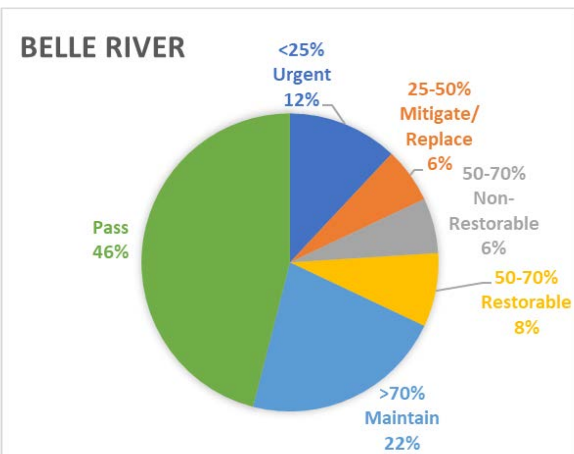
Recommended Action	Belle River	Comber	Essex	Harrow	Kingsville	Total
Less than 25% urgent replacement	2%	1%	1%	0%	0%	**4%**
25-50% Mitigate/replace	1%	1%	1%	1%	1%	**5%**
Total	**3%**	**2%**	**2%**	**1%**	**1%**	**9%**

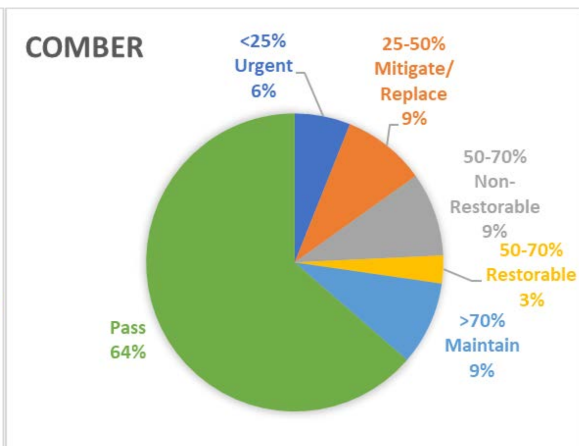
3.3 Pole Management Program

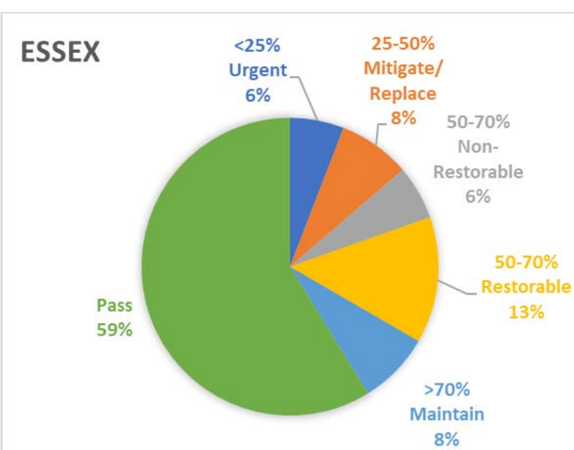
3.3.1 Trends

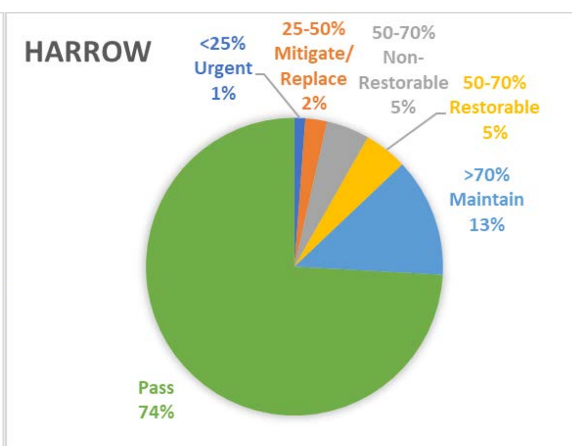
A comparison of poles requiring replacement/ mitigation as a percentage compared to number inspected is an initial indicator of which community has experienced more degradation of wood poles. The charts below show that Belle River has the highest number of degraded wood poles at 18%, followed by Comber at 15% and Essex at 14%. The sample size is small, making trend analysis difficult. A possible indicator is that older Lodgepole Pine and Red Pine poles are requiring replacement/ mitigation sooner than other species. These species make up 51% of pre-2000 poles inspected but make up 70% of pre-2000 poles requiring replacement or mitigation. Another possible indicator is pole proximity to water. Poles located closer to water are showing more defects.

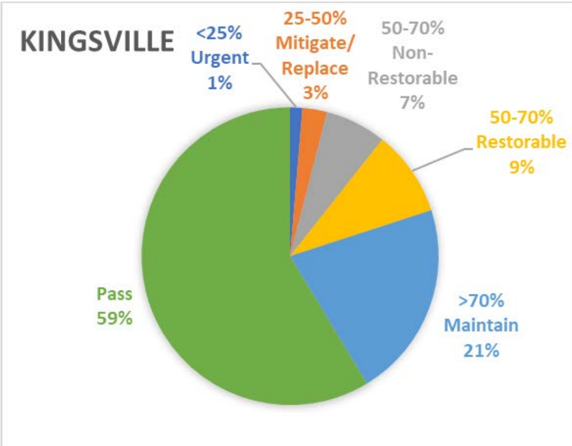
The following series of charts show the comparison of recommended actions to the total in each area.











Overall, the trend shows 9% of the poles inspected will require mitigation or replacement. If the trend continues, just under half of those poles that require replacement will require *urgent* replacement. This high percentage will reduce in future inspections, as the bulk of the defective poles will already be replaced. The number of poles to be inspected that are pre 2000 is unknown. It is estimated that it will be 55 – 80% of the poles in service.

Table 3-5 shows that 59% of the poles requiring replacement or mitigation were installed in the 1980s and 41% were in the 1990s.

Table 3-5. Percentage of Replacement or mitigation actions by decade of pole installation.

Recommended Action	1980s	1990s	Total
Less than 25% urgent replacement	26%	22%	48%
25-50% Mitigate/replace	33%	19%	52%
Total	**59%**	**41%**	**100%**

Table 3-6 shows the quantity of inspected poles by decade of pole installation by recommended action.

Table 3-6. Quantity of all recommended actions by decade of pole installation.

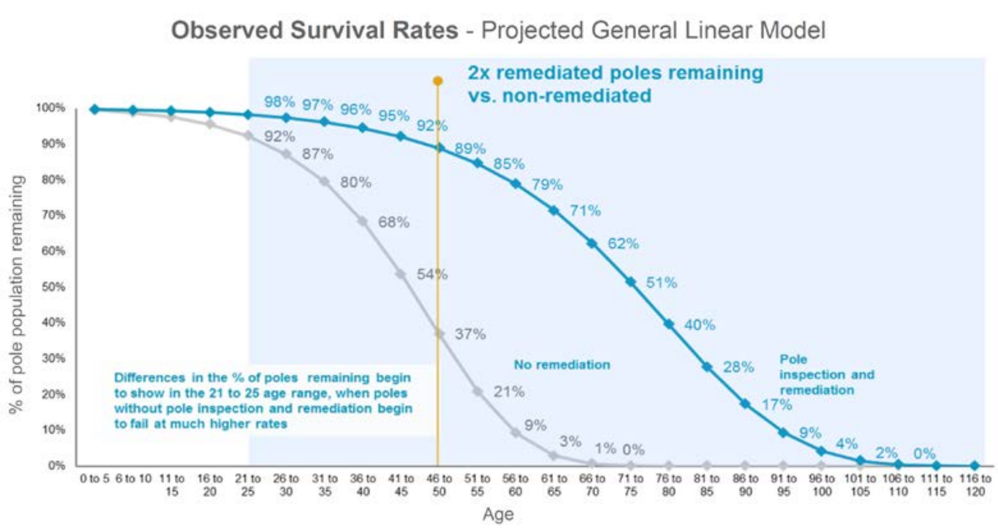
Recommended Action	1960s	1970s	1980s	1990s	2000s	2010s	Total
Less than 25%u replacement			7	6			13
25-50% Mitigate/replace			9	5			14
50-70% Non-restorable			11	7			18
50-70% Restorable		1	11	11			23
Greater than 70% maintain		2	15	27	1		45
Pass	2	2	33	133	7	4	181
Total	**2**	**5**	**86**	**189**	**8**	**4**	**294**

3.3.2 Recommend Future Inspection Areas and Initial Cycles Based on the Analysis.

It is recommended that ELK continue wood pole inspections, focusing on the pre 2000s in all areas. The recommendation is to complete the initial inspection as quickly as reasonably possible. It is also recommended that ELK continue analyzing data as more poles are inspected, to refine long term pole management program. An inspection cycle of 8 – 12 years would be practical after the initial inspection cycle and the implementation of a life extension program. The life extension program will slow the degradation of the pole to allow the longer cycles.

The poles with a recommended action of less than 25% Urgent replacement should continue to be replaced when identified. The required pole replacements classed as medium priority (25-50% Mitigate/Replace) can be planned with ELK's other projects to take advantage of opportunities to gain efficiency.

It is recommended that ELK perform life extension at the same time as the pole inspection. This is a cost-effective way to extend the life of the pole. Activities include applying internal treatments to slow or eliminate decay, external treatment at ground line to preserve the wood at that point, and treatments to control insects. Poles showing decay or insect damage would receive these treatments at the time of inspection. A study conducted by Osmose for the Electric Power Research Institute (EPRI) *Wood Pole Life Extension & The Case for Capitalization*, studied the data from over 600,000 poles to analyze the differences in service life for poles that received remedial retreatment and those that did not. The graph below came from that 2014 report.



Decay rates used in analysis are based on projections using a general linear model with a logistic link function and binomial variance
Source: Oliver Wyman analysis, Osmose 600k Wood Pole Survivor Rates by Decay Hazard Zone Initial Inspection vs. Recycle Inspection

Table 3-7 shows that 60% of the poles (68 out of 113) that had defects are recommended for life extension.

Table 3-7. Recommended actions by percentage.

Recommended Action	**Percentage**
Less than 25% urgent replacement	12%
25-50% Mitigate/replace	12%
50-70% Non-restorable	16%
50-70% Restorable	20%
Greater than 70% maintain	40%
Grand Total	**100%**

The most common defects were heart rot and surface rot which can be managed using internal treatments and ground line treatments.

APPENDIX A – POLES REQUIRING REPLACEMENT/MITIGATION

Poles requiring urgent replacement.

Structure #	Feeder	Year	Length	Class	Species	Pole Setting	Recommended Description	Main Condition
P800011	COMBER_2012	1990	40	3	LP	S	<25% Urgent Replacement	SR
P800165	COMBER_2012	1988	40	3	LP	S	<25% Urgent Replacement	HR
P900090	BELLE_2012	1983	45	2	UN	S	<25% Urgent Replacement	HR
P900782	BELLE_2012	1995	45	3	LP	S	<25% Urgent Replacement	HR
P900788	BELLE_2012	1995	45	3	LP	S	<25% Urgent Replacement	HR
P000803	ESSEX_2012	1986	30	4	LP	C	<25% Urgent Replacement	SR
P200357	HARROW_2012	1995	45	3	RP	S	<25% Urgent Replacement	HR
P001264	ESSEX_2012	1995	35	5	LP	S	<25% Urgent Replacement	SR
P400135	KINGSVILLE_2012	1989	45	3	RP	S	<25% Urgent Replacement	HR
P900755	BELLE_2012	1990	45	3	WC	S	<25% Urgent Replacement	HR
P900257	BELLE_2012	1985	45	3	LP	S	<25% Urgent Replacement	SR
P900371	BELLE_2012	1985	45	4	WC	S	<25% Urgent Replacement	HR
P000446	ESSEX_2012	1987	45	3	SP	S	<25% Urgent Replacement	SR

Poles requiring replacement.

Structure #	Feeder	Year	Length	Class	Species	Pole Setting	Recommended Description	Main condition
P800238	COMBER_2012	1994	45	4	LP	S	25-50% Mitigate or Replace	SR
P800138	COMBER_2012	1989	30	6	JP	S	25-50% Mitigate or Replace	HR
P800182	COMBER_2012	1985	40	4	LP	S	25-50% Mitigate or Replace	HR
P900095	BELLE_2012	1985	40	3	RP	S	25-50% Mitigate or Replace	SR
P000802	ESSEX_2012	1986	45	3	RP	C	25-50% Mitigate or Replace	HR
P200358	HARROW_2012	1992	45	4	RP	S	25-50% Mitigate or Replace	SR
P001265	ESSEX_2012	1995	45	3	LP	S	25-50% Mitigate or Replace	SR
P400611	KINGSVILLE_2012	1992	35	5	LP	S	25-50% Mitigate or Replace	SR
P400430	KINGSVILLE_2012	1986	45	3	SP	S	25-50% Mitigate or Replace	HR
P900260	BELLE_2012	1985	45	3	SP	S	25-50% Mitigate or Replace	SR
P900259	BELLE_2012	1985	45	3	SP	S	25-50% Mitigate or Replace	SR
P000447	ESSEX_2012	1987	45	3	LP	S	25-50% Mitigate or Replace	SR
P001292	ESSEX_2012	1987	40	4	LP	S	25-50% Mitigate or Replace	HR
P200081	HARROW_2012	1995	45	4	RP	S	25-50% Mitigate or Replace	HR

APPENDIX B – POLES TO BE CONSIDERED FOR LIFE EXTENSION

Structure #	Feeder	Year	Length	Class	Species	Pole Setting	Recommended Description	Main condition
P800240	COMBER_2012	1994	45	3	LP	S	>70% Maintain	MSe
P800218	COMBER_2012	1991	35	5	LP	S	>70% Maintain	
P800219	COMBER_2012	1991	45	3	SP	S	50-70% Restorable	
P800205	COMBER_2012	1981	40	3	RP	S	>70% Maintain	MSl
P000382	ESSEX_2012	1980	45	3	LP	A	50-70% Restorable	HR
P000538	ESSEX_2012	1980	45	2	LP	C	50-70% Restorable	MWe
P000540	ESSEX_2012	1980	50	2	LP	S	>70% Maintain	SR
P900091	BELLE_2012	1975	40	3	RP	S	50-70% Restorable	
P900094	BELLE_2012	1975	40	3	UN	S	>70% Maintain	HR
P900451	BELLE_2012	1995	45	3	LP	S	>70% Maintain	MSl
P900450	BELLE_2012	1995	45	3	RP	S	>70% Maintain	
P900416	BELLE_2012	1993	45	3	WC	S	>70% Maintain	MSl
P900412	BELLE_2012	1993	45	3	LP	S	>70% Maintain	
P200245	HARROW_2012	1985	45	4	LP	S	>70% Maintain	
P200216	HARROW_2012	1992	45	4	LP	C	50-70% Restorable	SR
P200217	HARROW_2012	1992	50	4	SP	S	>70% Maintain	
P200218	HARROW_2012	1992	50	3	RP	S	>70% Maintain	
P200222	HARROW_2012	1992	45	3	LP	S	>70% Maintain	
P200223	HARROW_2012	1992	45	4	LP	S	>70% Maintain	SR
P200224	HARROW_2012	1992	45	4	JP	S	>70% Maintain	SR
P200071	HARROW_2012	1986	45	4	SP	S	>70% Maintain	SR
P200359	HARROW_2012	1992	45	3	LP	S	50-70% Restorable	
P001268	ESSEX_2012	1993	35	5	LP	S	50-70% Restorable	HR
P001139	ESSEX_2012	1970	45	5	LP	S	>70% Maintain	
P400367	KINGSVILLE_2012	1980	45	4	LP	S	50-70% Restorable	SR
P400379	KINGSVILLE_2012	1995	45	3	LP	S	>70% Maintain	
P400378	KINGSVILLE_2012	1995	45	4	LP	S	>70% Maintain	
P400377	KINGSVILLE_2012	1995	45	4	RP	S	>70% Maintain	MWe
P400376	KINGSVILLE_2012	1980	45	3	PP	S	50-70% Restorable	SR

Structure #	Feeder	Year	Length	Class	Species	Pole Setting	Recommended Description	Main condition
P400939	KINGSVILLE_2012	1990	25	4	LP	S	50-70% Restorable	SR
P400420	KINGSVILLE_2012	1990	45	4	RP	S	>70% Maintain	PR
P400182	KINGSVILLE_2012	1990	45	3	LP	S	>70% Maintain	
P400185	KINGSVILLE_2012	1985	45	3	WC	C	50-70% Restorable	PR
P400187	KINGSVILLE_2012	1985	45	4	WC	S	>70% Maintain	
P400188	KINGSVILLE_2012	1980	45	3	WC	S	>70% Maintain	
P400190	KINGSVILLE_2012	1980	45	3	WC	C	>70% Maintain	
P400160	KINGSVILLE_2012	1980	45	3	WC	S	50-70% Restorable	PR
P400612	KINGSVILLE_2012	1990	35	4	JP	S	>70% Maintain	
P400615	KINGSVILLE_2012	1990	35	4	LP	S	>70% Maintain	
P400561	KINGSVILLE_2012	1995	45	3	RP	S	>70% Maintain	PR
P400250	KINGSVILLE_2012	1998	45	3	RP	S	>70% Maintain	SR
P400254	KINGSVILLE_2012	1989	50	3	SP	S	>70% Maintain	PR
P400257	KINGSVILLE_2012	1989	50	3	SP	S	>70% Maintain	PR
P400429	KINGSVILLE_2012	1987	50	3	SP	S	50-70% Restorable	SR
P400434	KINGSVILLE_2012	1989	45	3	WC	S	>70% Maintain	
P400466	KINGSVILLE_2012	1998	45	3	RP	S	>70% Maintain	HR
P400545	KINGSVILLE_2012	1994	45	3	SP	S	50-70% Restorable	
P900823	BELLE_2012	1990	45	3	WC	S	>70% Maintain	
P900830	BELLE_2012	1990	45	3	WC	S	50-70% Restorable	HR
P900708	BELLE_2012	1992	45	3	RP	S	50-70% Restorable	HR
P900753	BELLE_2012	1988	45	3	LP	S	>70% Maintain	
P900756	BELLE_2012	1995	45	3	WC	S	>70% Maintain	PR
P900263	BELLE_2012	1985	45	2	SP	S	>70% Maintain	
P900261	BELLE_2012	1985	45	3	SP	S	50-70% Restorable	SR
P900152	BELLE_2012	1985	45	3	WC	S	>70% Maintain	
P900213	BELLE_2012	1985	45	3	WC	S	>70% Maintain	
P000718	ESSEX_2012	1995	45	3	LP	S	50-70% Restorable	SR
P000719	ESSEX_2012	1990	40	3	LP	S	>70% Maintain	SR

Structure #	Feeder	Year	Length	Class	Species	Pole Setting	Recommended Description	Main condition
P000428	ESSEX_2012	1989	45	3	LP	S	50-70% Restorable	SR
P000448	ESSEX_2012	1987	35	4	SP	S	50-70% Restorable	SR
P000026	ESSEX_2012	1987	45	3	SP	S	50-70% Restorable	SR
P001310	ESSEX_2012	1990	45	3	SP	S	>70% Maintain	
P200092	HARROW_2012	2001	30	3	WC	S	>70% Maintain	
P200088	HARROW_2012	1991	35	4	LP	S	>70% Maintain	
P200127	HARROW_2012	1995	45	4	LP	S	>70% Maintain	SR
P200308	HARROW_2012	1990	45	4	SP	S	50-70% Restorable	SR
P200310	HARROW_2012	1990	45	3	SP	S	50-70% Restorable	SR
P200313	HARROW_2012	1987	45	3	WC	S	>70% Maintain	

APPENDIX C – CUSTOMER SURVEY REPORT

METSCO
MAKING IT POSSIBLE

Appendix C:E.L.K. Energy Distribution System Plan Customer Survey 2021 Report

Prepared For: E.L.K. Energy

PRIVILEGED & CONFIDENTIAL

Prepared By:

METSCO Energy Solutions
99 Great Gulf Drive, Unit #2
Concord, ON L4K 5W1

Executive Summary

As part of E.L.K. Energy Inc (“E.L.K.”) developing their 2022-2026 Distribution System Plan (“DSP”), an online customer survey has been undertaken to gather feedback from E.L.K. customers on their proposed plan. In total, 290 residential and business customers responded to the survey, across its six service areas. Key questions and responses from the survey can be best categorized under the following categories, including (a) customer segmentation and demographics, (b) E.L.K. performance, and (c) capital investments and customer preferences. The survey results identified three clearly defined customer priorities:

1. ensuring reliable electric service,
2. reducing the overall number of outages, and
3. prioritizing investments that will help improve system reliability, power quality, efficiency, and operations.

Further detail of this feedback is explored below.

Customer Segmentation and Demographics

The representation of customers who responded to the survey cover all customer types - residential and business - across all six service areas. The response rate covers approximately 2% of E.L.K. customer base, which is within the range of a typical online utility survey. The majority of responses came from customers located in the Kingsville and Essex regions, which are the two largest population centres in E.L.K.’s service territory.

E.L.K. Performance

E.L.K. customers were split between being satisfied or dissatisfied with E.L.K. performance and system reliability. Dissatisfaction was notably higher when the question focused specifically on system reliability. Those who indicated they are not satisfied with these services have also indicated that E.L.K. should improve communications when an outage occurs and reduce the total number of outages experienced.

Capital Investment & Customer Preferences

The majority of E.L.K.’s customers were either satisfied with E.L.K.’s proposed pace of investments in the DSP or preferred to see a further increase the pace of investments proposed to see improvements made to system reliability, service and operations. ELK’s proposed plans, including the proactive replacements of deteriorating and end of life assets, bucket truck replacements, the deployment of a line fault indicators pilot project, and the development and implementation of an IT strategy, are all in favour of meeting ELK’s customer needs and priorities, while also ensuring the continued safe and reliable operation of the distribution system at affordable rates for customers.

Overall, there is strong support for E.L.K.’s proposed plan, with customers either agreeing that this is the right approach or indicating that they trust that E.L.K., being the expert, will make the right decisions.

Contents

1. Introduction

As part of E.L.K. Energy ("E.L.K.") developing their 2022-2026 Distribution System Plan ("DSP") and ensuring that their proposed capital investments are aligned to customer preferences, E.L.K. engaged METSCO Energy Solutions Inc. ("METSCO") in the preparation and development of a Customer Survey ("DSP Survey"). The DSP Survey was deployed across their entire customer base in order to capture information relating to the following categories:

- Customer Details (service area, customer type, etc.)
- Overall Performance of E.L.K. (services provided by E.L.K., customer satisfaction with system reliability, power restoration, planned outages, customer response times, etc.)
- E.L.K. Capital Investments (customer preferences on System Renewal and General Plant investments as well as System O&M investments)

In an effort to minimize customer burden and obtain feedback in a timely and cost-efficient manner, the survey was deployed using an online survey platform (SurveyMonkey), with invitations to the platform being distributed and advertised via email, social media channels. The online survey was made accessible to customers from November 4, 2021, to November 10, 2021 (inclusive). To incentivize customers to participate in the survey and provide feedback, E.L.K. donated $300 to the Belle River, Essex and Kingsville foodbanks, and all participants that completed the survey were included in a random draw for new iPad, which was awarded on November 30, 2021.

This survey was designed in such a manner to first gather information regarding E.L.K.'s customer base, including identifying if the customers are residential or business customers, and confirming their location within E.L.K.'s service territory. Following this, the survey focused on general satisfaction with services provided by E.L.K. and the reliability and restoration of those services. The survey then provided key information on E.L.K.'s proposed capital expenditure plans ("CAPEX Plan") embedded within the DSP, including investments embedded within the System Renewal and General Plant categories, thereby providing customers with the necessary context to respond to questions relating to the proposed CAPEX Plan.

The following report summarizes the survey results and conclusions derived from the responses. The report is structured under the three following categories:

- Segmentation and Demographics
- Overall Performance
- Capital Investment

A conclusion section then summarizes the outcomes that E.L.K. can use from the customer survey.

2. Segmentation and Demographics

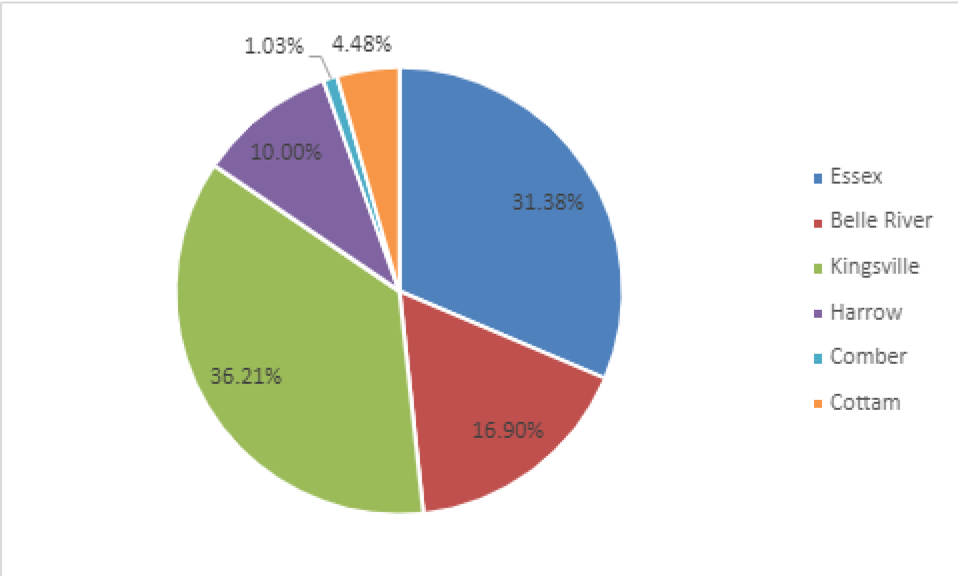
This section provides details and insights into the types of customers who responded to the survey and associated customer demographics.

A total of 290 E.L.K. customers with a good representation from all six service areas responded to the survey. The total number of customers that responded to the survey, broken down by service area, is listed in Table 2.1 and shown in Figure 2.1.

Table 2.1: Number of Customers who Responded across All Six Service Areas

E.L.K. Service Area	No. of Customers Surveyed	Percentage of Customer who responded
Belle River	49	16.90%
Comber	3	1.03%
Cottam	13	4.48%
Essex	91	31.38%
Harrow	29	10.00%
Kingsville	105	36.21%
Total No. of Customers	290	100%

Figure 2.1: Percentage Of Customer Survey Responses by Service Area



Of the 290 customers surveyed, 286 were residential customers and 4 were business customers located within E.L.K.'s service territory. The split of residential versus business customers (98.6% Residential customers and 1.4% Business customers) who responded to the survey is closely representative of E.L.K.'s overall customer base (~89% Residential customers and ~11% Business customers).

2.1 Conclusions on Segmentation and Demographics

The total number of customers who have responded to the survey is lower than previous customer engagements that E.L.K. has undertaken. However, the customers who did respond are representative of E.L.K.'s customer base (service area & type), and it is expected that the overall results would remain proportional and aligned even if the surveyed group was expanded. As a result, E.L.K. is able to use these results in a meaningful way to help shape and validate the DSP.

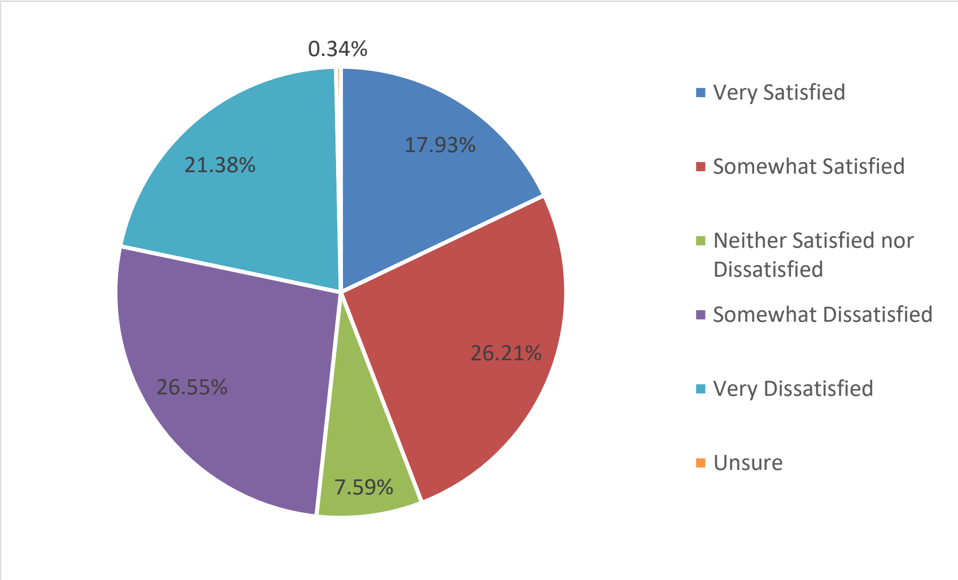
3. Overall Performance

This section summarises customer feedback and preferences pertaining to E.L.K.'s overall performance with respect to system reliability and customer service.

3.1 Overall Performance

Two main questions were posed to customers to assess satisfaction with E.L.K.'s overall performance and with the reliability of electricity services that E.L.K. provides. As shown by the results in Figure 3.1, there is a fairly even split between customers that are very satisfied or somewhat satisfied (44%) with those that are very dissatisfied or somewhat dissatisfied (48%). The remaining 8% were neither satisfied nor dissatisfied or unsure.

Figure 3.1: Thinking Specifically About the Services Provided to You and Your Community by E.L.K., How Satisfied or Dissatisfied Are You Overall with The Services That You Receive?



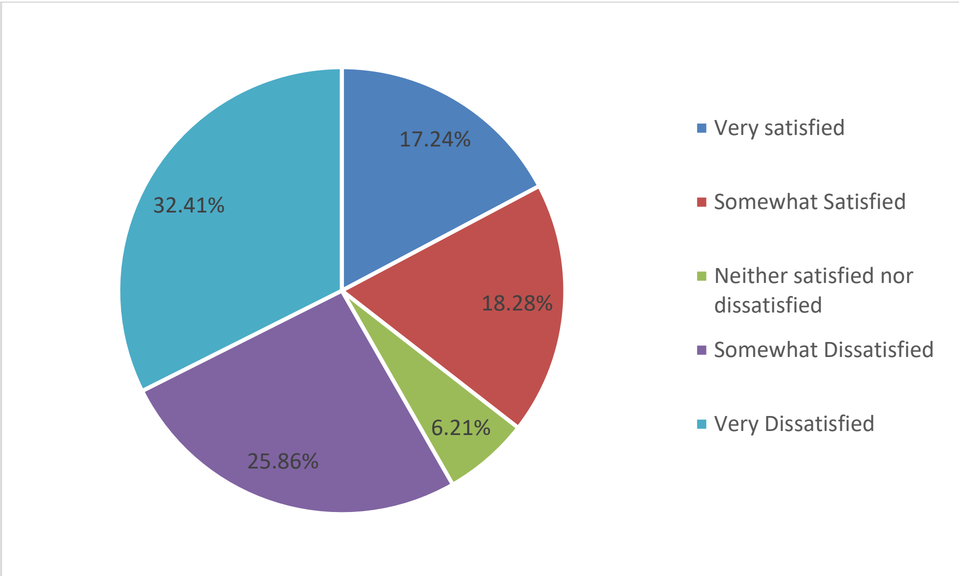
Out of the 48% of customers who are somewhat dissatisfied or very dissatisfied, 79% of these are situated in the Essex and Kingsville regions, with the remaining 21% being situated within the Belle River, and Harrow regions. There were no dissatisfied responses from the Comber or Cottam regions, however only 5.5% of responses were from those regions. Certain customers also provided feedback to further explain their satisfaction results. From those who did provide comments, a few examples are presented below:

- *"I have been a Kingsville resident since 1969. There seems to be more power outages than there used to be. I have generally been very satisfied with the service."*
- *"We have been a customer since 1994 and knowing that the electricity comes through another entity, we are completely satisfied with E.L.K."*
- *"Other than the several outages, I am satisfied with E.L.K.'s services."*

Overall, there is a split between E.L.K.'s customers that are very satisfied or somewhat satisfied and those that are somewhat dissatisfied and very dissatisfied with E.L.K.'s overall level of service, with the majority of dissatisfaction noted in the Essex and Kingsville regions. E.L.K. should look to ensure that they can continue to maintain a high level of service while looking to address the issues these customers have experienced to better improve the service they provide.

Figure 3.2 illustrates E.L.K.'s customer satisfaction levels with respect to the reliability of electricity services provided. Overall satisfaction with services provided by E.L.K. described above was more favourable compared to the satisfaction of customers around reliability with only 36% of customers feeling somewhat or very satisfied. Dissatisfaction was prominent in this area, with 58% of respondents being somewhat dissatisfied or very dissatisfied with the reliability of electricity services from E.L.K.

Figure 3.2: How satisfied or dissatisfied are you with the reliability of your electricity service, as judged by the number of outages you experience?



Somewhat dissatisfied or very dissatisfied responses were received in all service areas except for Comber (where no dissatisfied responses were received). It should be noted that only 1% of all survey responses were received from the Comber region. When looking at specific regions, both Essex and Kingsville made up 81% of the somewhat dissatisfied and very dissatisfied responses. This aligns with the level of overall dissatisfaction previously described for these two regions. It is important to note that Essex and Kingsville are the two largest population centres serviced by E.L.K., however the prevalence of dissatisfaction around service and reliability in these areas must be considered and addressed.

Below are some of the comments left by these customers:

- *"The number of outages is disgraceful even if the duration is short. It is unbelievable that customers have to consider adding household surge protectors to prevent loss of electronic appliances."*

- *"I have had to put up with multiple power outages and brown outs. I am disappointed in the level of service and hope that all can be rectified with no increases to my bill as I already had to replace household electronics due to power surges."*

- *"I have sent emails when power outages have occurred in Kingsville but have never received acknowledgement."*

- *"More timely updates regarding outages and the estimated time for resumption of service"*

3.2 Conclusions on Overall Performance

Based on the overall service and reliability satisfaction results presented above, there is room for improvement. The dissatisfied feedback was primarily received from two population centres served by E.L.K., Essex and Kingsville. To address this, ELK has proposed initiatives within the 2022 – 2026 DSP application that are aimed at improving the reliability and customer service within these areas. For example, the deployment of line fault indicators pilot project in the Kingsville area will begin to directly address reliability concerns heard from customers in the area.

4. Capital Investment

This part of the survey provided specific information regarding E.L.K.'s investment plans from 2022 to 2026. E.L.K. used this part of the survey to gather feedback about this plan to help further refine its plan. These investment plans have been centralized into E.L.K.'s DSP, which adheres to the planning requirements as established by the OEB.

The following subsections provide a summary of the survey preamble and results relating to the customer preferences with respect to E.L.K.'s proposed capital investment plan and the potential resulting reliability impacts associated with executing this plan. Questions covered a range of topics, from overall priorities for customers, to specific questions regarding investments within two DSP investment categories, System Renewal and General Plant. Capital investment plans were identified in the System Service category within E.L.K.'s DSP for the fault indicator project, however they were only identified after release of the customer survey and feedback was not obtained on the System Service proposed scope of work for the 2022 – 2026 period.

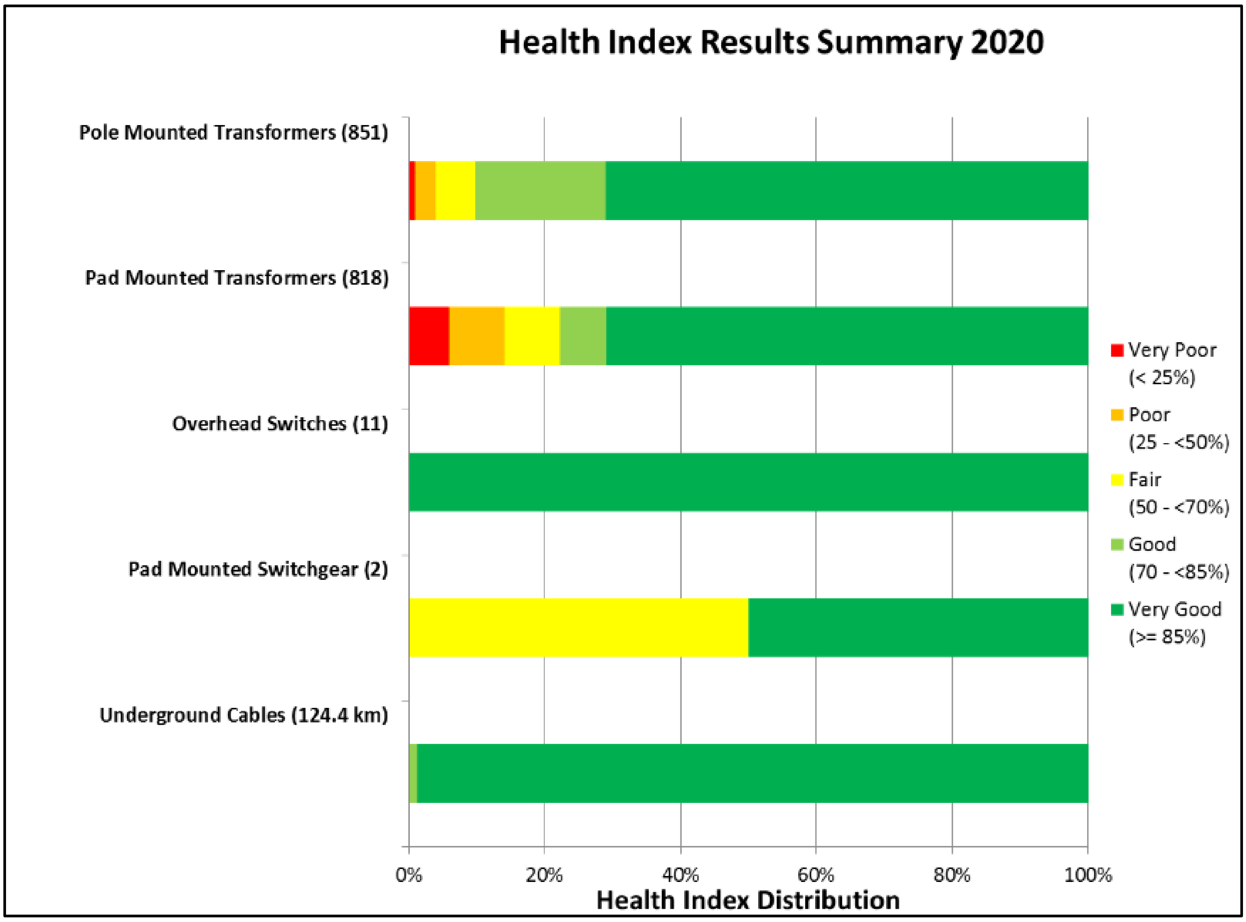
The following preambles were provided for each investment category to better define the investments taking place within each category, as well as providing further detail on how the investments will introduce benefits into the system. The complete survey can also be found in Appendix A.

System Renewal

E.L.K.'s System Renewal investments are targeted towards the replacement/renewal of assets – including transformers, poles, underground cables, and overhead conductors – that are past their typical useful lives (TUL). In addition, functionally obsolete infrastructure that no longer aligns with E.L.K.'s current operating practices will be replaced with new infrastructure that aligns with E.L.K.'s current standards.

E.L.K. undertook two investigative activities as part of their System Renewal planning activities for this DSP. Firstly, leveraging inspection results, E.L.K. conducted an asset condition assessment (ACA) for a limited proportion of their assets. From these results, three asset categories of pole mounted transformers, overhead switches and underground cables had health scores classified as “good” or “very good” and an overall health index of 80%. With respect to the asset category of concern, pad mounted transformers had half of the asset units assessed classified as “very poor” health condition. The health index results from the ACA can be seen below in Figure 4.1.

Figure 4.1 – System-Wide Age & Condition Summary Results



Secondly, E.L.K. used a third-party vendor to conduct a pole condition health assessment. The assessment reviewed approximately 9% of E.L.K.’s network of wood poles to conduct on site testing and data collection and recommendations for a pole management program. The findings of the report identified 4% of the sampled poles were deemed for urgent repair/treatment, with another 5% categorized as mitigate/replace in the near-term.

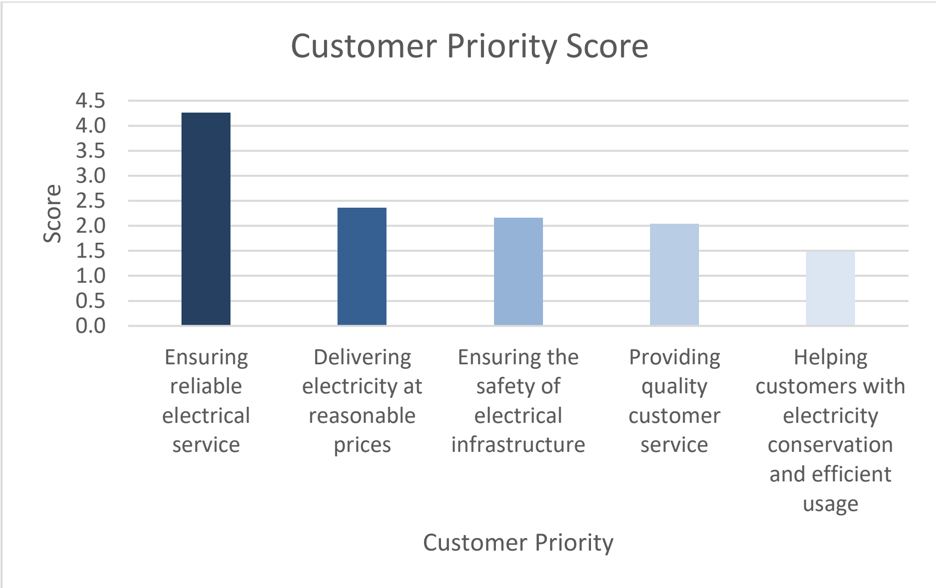
General Plant

General Plant investments will be focused on initiatives that support the 24/7 operations of E.L.K.’s distribution system, including upgrades to E.L.K.’s facilities and buildings that house employees and equipment, the replacement of critical Fleet vehicles that transport crews to respond to outages, replacement, and upgrades to critical IT hardware and software necessary to manage and analyze the system, as well as investment into operational technologies including new testing technologies to better monitor the performance of the grid.

4.1 Customer Priorities

Customers were asked to select their top priorities that E.L.K. should focus on over the next five-year forecast period (2022-2026), as well as the top system reliability priorities that the utility should look to address over the 2022-2026 planning period. The results from these questions are illustrated in Figures 4.2 and 4.3.

Figure 4.2: Using a scale from 1 (not important) to 5 (very important), please rate the priorities E.L.K. should undertake when spending capital ratepayer dollars?



As shown in Figure 4.2, ensuring reliable electrical service was the top priority for customers that completed the survey, with a weighted score of 4.26/5 making this priority a tier of its own. In the next tier were two priorities that E.L.K. should undertake with respect to ratepayer dollars and that is delivering electricity at reasonable prices (2.36/5) and ensuring the safety of electrical infrastructure (2.16/5).

Figure 4.3: Using a scale from 1 (not important) to 5 (very important), please rate your priority when addressing power reliability in the E.L.K. service territories?

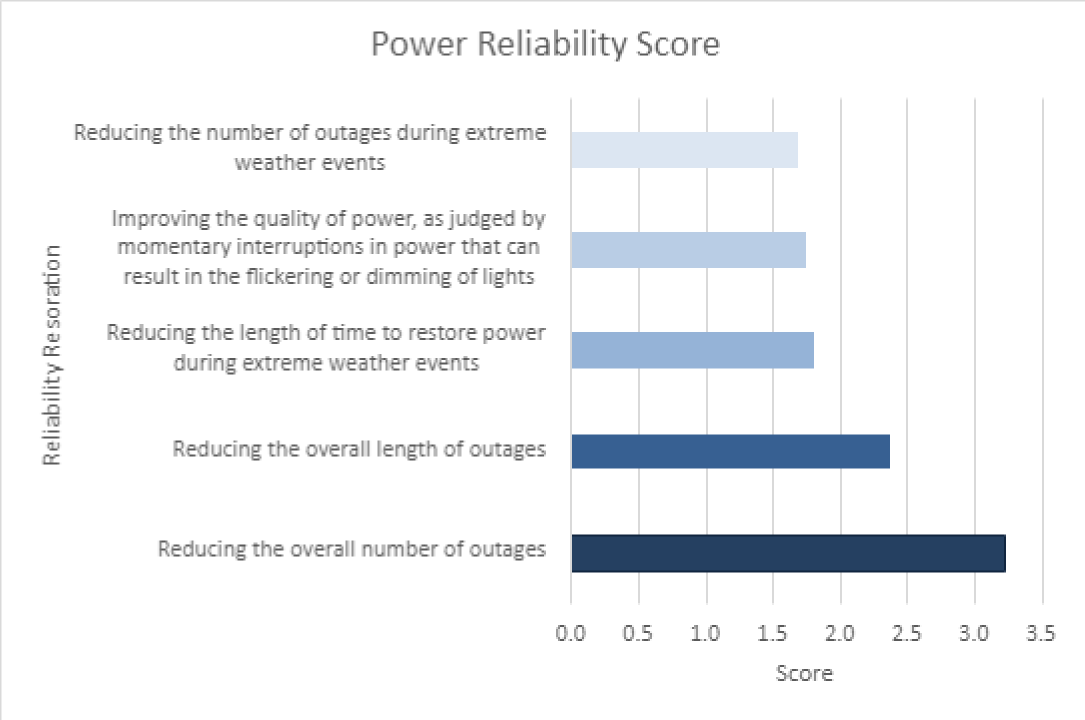


Figure 4.3 illustrates that E.L.K. should focus on reducing the overall number of outages, followed by a reduction in the overall length of outages when they occur. These two priorities were in tiers of their own for customer preference, with the reduction of overall number of outages obtaining a score of 3.23/5 and reducing the overall length of outages obtaining a score of 2.37/5. E.L.K.'s proposed capital plans over the 2022-2026 period are well aligned with these customer priorities, as outlined in the following sub-sections.

4.2 System Renewal

In regards to the System Renewal category, customers were asked about the pacing of investments and what E.L.K. should be striving to achieve. Specifically, the question asked was "*Recognizing the conditions of E.L.K.'s asset base, please select one of the following options that best describes your preferences towards how E.L.K. can be pacing their assets replacements over the next 5 years*":

- **57%** of respondents preferred that E.L.K. "increase the pace of System Renewal spending, such that assets that are in "very poor" or "poor" condition, or have reached end of useful life, are replaced";
- **13%** of respondents selected the option noting that "the pace of System Renewal spending as specified in E.L.K.'s plans is sufficient";
- **2%** of respondents preferred that E.L.K. "further reduce the pace of System Renewal spending"; and
- **28%** were Unsure.

While a significant portion of the respondents did not provide a preference for the pacing and prioritization of System Renewal activities, those that did indicated a significant preference towards increasing the pace of System Renewal spending such that deteriorated and end of life assets are addressed. This is valuable insight that is taken into consideration when planning for and prioritizing System Renewal work.

Given that System Renewal investments support reliability, respondents were asked "*recognizing that System Renewal supports reliability performance, over the next 5-year period, please select one of the following options that describes your preferences with respect to system reliability performance*":

- **69%** of respondents preferred that E.L.K. "prioritize improvements to system reliability performance, thereby resulting in less customer outages per year with a reduced outage duration";
- **18%** of respondents preferred that E.L.K. "continue to deliver the same level of system reliability performance";
- **2%** of respondents preferred that E.L.K. "deprioritize improvements that support system reliability performance, thereby resulting in more customer outages per year with increased outage duration"; and
- **11%** were Unsure.

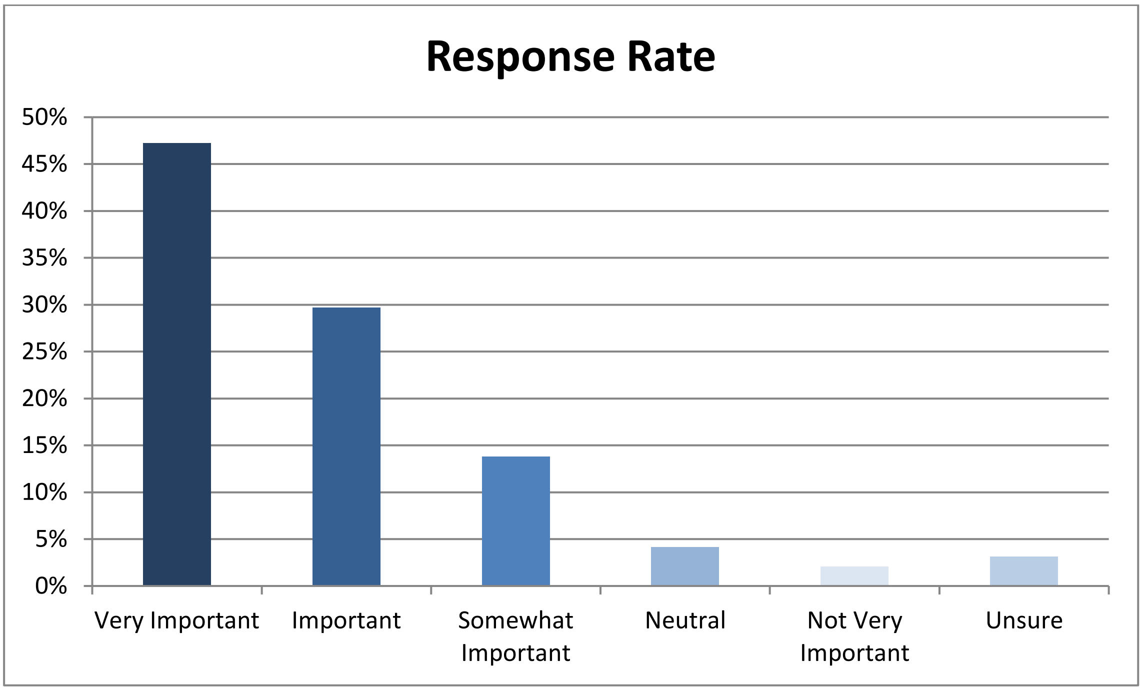
Close to 70% of respondents identified a preference towards prioritizing improvements to system reliability. This aligns with the number of somewhat dissatisfied or very dissatisfied customer responses relating to reliability and service as seen in Figure 3.1 and supports the proposed pacing and prioritization of System Renewal work identified in the DSP. Proposed programs designed to help address these concerns include E.L.K.'s proactive pole and transformer replacement programs, as well as E.L.K.'s ongoing inspections and maintenance practices.

4.3 General Plant

The intent of the final section of the survey was to gather customers views on E.L.K.'s proposed General Plant investments. This included questions on the pacing and prioritization of investments as well as specific questions regarding fleet vehicles, facilities, and operational information technology investments.

The survey asked participants to identify "*how important do you think it is that E.L.K. upgrade software and systems to support customer service like GIS, outage management including outage mapping, billing and communications, and functional services?*" Responses to this question are shown in Figure 4.4 below. Over 47% of respondents found it to be "very important" to improve systems that support customer service and reliability of power, with another 30% of respondents feeling this is "important". The responses that were identified as "neutral", "not very important" or "Unsure" amounted to 9%.

Figure 4.4 – How important is it for E.L.K. to upgrade systems that support customer service and reliability of power?



Respondents were also asked the following "*recognizing that General Plant investments allow for E.L.K.'s 24/7 operation to be maintained, which of the following statements best represents your point of view?*"

- **43**% of respondents stated "E.L.K. should increase the pace of General Plant investments such that the utility can further enhance and accelerate utility efficiencies and operational improvements over the next 5-year period";
- **32**% of respondents stated "The pace of General Plant spending as specified within the 2022 – 2026 DSP is necessary to enable E.L.K. to continue operating in a fully functional and efficient manner";
- **1%** responded that the pace of investments should be reduced; and
- **24**% of respondents were unsure.

Over 40% of respondents identified a preference towards accelerating the capital investment in General Plant initiatives within this DSP period, while another 32% understood that capital spending in General Plant was required to support the fully functional operation of the distribution system. E.L.K.'s planned investments in this category, including the purchase of two new fleet vehicles, multiple IT improvements including an outage page on the website and GIS capabilities will support further efficient operation of the distribution system for E.L.K. customers. With these investments E.L.K. forecasts improvements to reliability, outage response and access to outage information for customers in all of its service territories.

Customers were also given the ability to provide overall feedback to E.L.K. regarding the capital investment plan. Below are some of the comments left by these customers:

- *"Reliability and investment in the system should be paramount"*
- *"This [survey] tells me E.L.K. wasn't investing enough in infrastructure for the last 4 years which has resulted in poor power quality to end users"*
- *"Perfection is usually out of reach, but continual improvements are the next best outcome"*

4.4 Conclusions on E.L.K.'s Capital Investment Plan

The results from this section of the survey have indicated that addressing day-to-day reliability, reducing the total number of outages, and prioritizing investments that will help improve services, reliability and operations are the top three priorities that E.L.K. should be focusing on.

The results of the customer survey questions identified in the section above align with the final question that was issued to survey participants. The final question inquired if "*based on your knowledge and understanding of E.L.K.'s overall DSP, which of the following statements best aligns with your opinion of E.L.K.'s DSP and associated investments over the next 5-year period?"*

- **42%** of respondents stated "I'm not sure if this is the right approach but I trust E.L.K. as the expert to make the right decisions";
- **34%** of respondents stated "I believe this is the right approach to continue to manage the safe and reliable performance of the system"; and
- **24%** of respondents stated "I don't believe this is the right approach and E.L.K. should consider revising their plans and strategy"

It is clear that customers have identified the areas of focus of improvements in the distribution for E.L.K. in this DSP, but the majority also support that E.L.K. is the expert in the area and trust the capital investment decisions that are proposed within this DSP for the next 5-years.

Overall, customer preferences generally align with the proposed plans outlined in the DSP. Investments are needed to address customer concerns and improve system reliability and operations, and E.L.K.'s proposed capital investment plans strive to achieve these goals.

5. Conclusions

Although only 2% of ELK's customer base responded to this survey, the customers who did respond are representative of E.L.K.'s customer base (service area & type), which has enabled E.L.K. to use the results in a meaningful way to help shape and validate the DSP.

Based on the results outlined in this report, customers have identified a strong preference towards E.L.K. addressing day-to-day reliability, reducing the number of outages on the system, and ensuring that investments are made towards improving system services, reliability and operations.

There remains room to improve customer satisfaction with respect to overall service, system reliability and outage response time. Those who indicated they are not satisfied with these services have also indicated that E.L.K. should improve communications when an outage occurs and reduce the number of outages experienced while ensuring that investments made to address these concerns are made prudently for the benefit of system performance.

Most customers were found to be either satisfied with E.L.K.'s proposed pace of investments in the DSP or preferred to see a further increase in the pace of investments proposed. This supports E.L.K.'s proposed plans, particularly under the System Renewal and General Plant categories. ELK's proposed plans, including the proactive replacements of deteriorating and end of life assets, bucket truck replacements, the deployment of a line fault indicators pilot project, and the development and implementation of an IT strategy, are all in favour of meeting ELK's customer needs and priorities, while also ensuring the continued safe and reliable operation of the distribution system at affordable rates for customers. E.L.K. will continue to propose and execute on these investments to address customer concerns, while balancing what the system needs and ensuring that rates remain affordable.

6. Appendix A - Customer Survey Questions & Preamble

Customer Survey 2021 – E.L.K. Energy Inc. Distribution System Plan (2022-2026)

Introduction

About E.L.K. Energy Inc.

E.L.K. Energy Inc. (E.L.K.) is an electricity distributor licensed by the Ontario Energy Board (OEB). E.L.K. provides electricity distribution services in the City of Essex, the town of Kingsville, village of Belle River, and communities of Harrow, Comber and Cottam, serving approximately 12,600 customers. E.L.K. owns and operates 89km of overhead distribution feeders and 79km of underground distribution circuits, with bulk power provided by four Hydro One owned transformer stations.

E.L.K. is committed to the pursuit of excellence in safety, reliability and cost control for the customers and communities we serve. E.L.K. strives to be the trusted energy advisor for our customers and continuing to create value for our shareholders.

What is the purpose of this survey?

E.L.K. is conducting this voluntary survey as part of its upcoming submission of its 2022-2026 Distribution System Plan (DSP) to learn more about how E.L.K.'s investment plans can best reflect the needs and preferences of its customers. The information collected will be used to further refine investment decision-making and will be submitted as part of its upcoming Cost of Service (COS) Application. By participating in this survey, you consent to E.L.K. utilizing your responses as a key input into the COS filing process.

Part A: General

Thank you for taking the time to complete this survey. The following questions are to verify your customer details. These details will not be used for any other reason. Your responses will still be treated anonymously. Please have a copy of your E.L.K. Energy bill on hand.

Figure 2: Sample E.L.K. Energy Bill

1. **Please enter your Customer Account Number. Figure 2 shows where this is found on your bill.**

<INSERT NUMBER>

2. **Are you a residential or business customer?**
   a. **Residential**
   b. **Business**

3. **Which of the service areas below are you located within?**
   c. **Essex**
   d. **Belle River**
   e. **Kingsville**
   f. **Harrow**
   g. **Comber**
   h. **Cottam**

Part B: Overall Performance of E.L.K.

Preamble

This section looks to explore your experience with E.L.K. Energy's overall performance and how satisfied you are with the services you receive, including system reliability, billing, and customer service. We are also looking to understand the priorities that you think E.L.K. should focus on.

1. **Thinking specifically about the services provided to you and your community by E.L.K., how satisfied or dissatisfied are you overall with the services that you receive?**
   a. **Very Satisfied**
   b. **Somewhat Satisfied**
   c. **Neither Satisfied nor Dissatisfied**
   d. **Somewhat Dissatisfied**
   e. **Very Dissatisfied**
   f. **Unsure**

2. **Overall, how satisfied, or dissatisfied are you with the reliability of your electricity service, as judged by the number of outages you experience?**
   a. **Very satisfied**
   b. **Somewhat Satisfied**
   c. **Neither satisfied nor dissatisfied**
   d. **Somewhat Dissatisfied**
   e. **Very Dissatisfied**
   f. **Unsure**

Part C: E.L.K. DSP

Preamble

This part of the survey is to provide specific information regarding E.L.K.'s investment plans from 2022 to 2026. E.L.K. is looking to gather feedback to help further refine the investment plans. These investment plans have been centralized into E.L.K.'s Distribution System Plan (DSP), which adheres to the planning requirements as established by the OEB.

To create the DSP, E.L.K. focuses on four key organizational objectives to meet the OEB requirements of a DSP filing. Specifically, the four outcomes are (1) Customer Focus: a DSP filing must demonstrate that distribution services are provided in a manner that responds to customer preferences; (2) Operational Effectiveness: a DSP must show that E.L.K.'s asset management and capital expenditure planning processes are designed for continuous improvements in productivity and cost performance; (3) Public Policy Responsiveness: E.L.K.'s DSP must explain how planning processes are integrated such that government-mandated expenditures can be undertaken in a timely manner; and (4) Financial Performance: that a DSP must show that E.L.K.'s financial viability and operational effectiveness will endure over the long-term.

On average, E.L.K. plans to spend approximately $1.4 million in capital expenditures annually over the next five-year period from 2022 to 2026. This investment level represents an overall increase of 17% in the average annual capital expenditures made to the system over the last 5-year period from 2017 to 2021. As a result of this proposed increase, customers will see an approximate average increase of X% on their electricity bill over the next five-year period when accounting for the cost of inflation.

System Renewal

E.L.K.'s "System Renewal" investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and maintain the ability to provide customers with electricity services. To help inform System Renewal activities in the 2022-2026 DSP, two independent third-party reports were used as inputs to identify targeted investments.

The first report, an Asset Condition Assessment (ACA), identified the condition of E.L.K.'s key distribution assets. For each asset category, the available data was assessed, a Health Index distribution was determined, and a condition-based Flagged for Action Plan was developed. The resulting Health Index distribution for each asset category is shown in Figure *3*. Over the 2022-2026 period, E.L.K. is planning to address the backlog of pad and pole mounted transformers that are flagged as "very poor" and "poor", starting with those that present the highest risk.

The second report, a pole inspection report, assessed the condition of the poles in E.L.K.'s distribution fleet. The resulting breakdown of pole condition is shown in Figure *4*. Over the 2022-2026 period, E.L.K. is planning to address poles flagged for replacement and conduct a detailed pole inspection analysis in all areas, with particular focus on those poles installed before 2000, and use this data to develop a long-term pole management program.

In the 2022-2026 DSP filing, E.L.K. is forecasting approximately $750k of System Renewal spend per year, which is approximately 7% above the average pace of System Renewal spend over the previous 5-year period from 2017-2021.

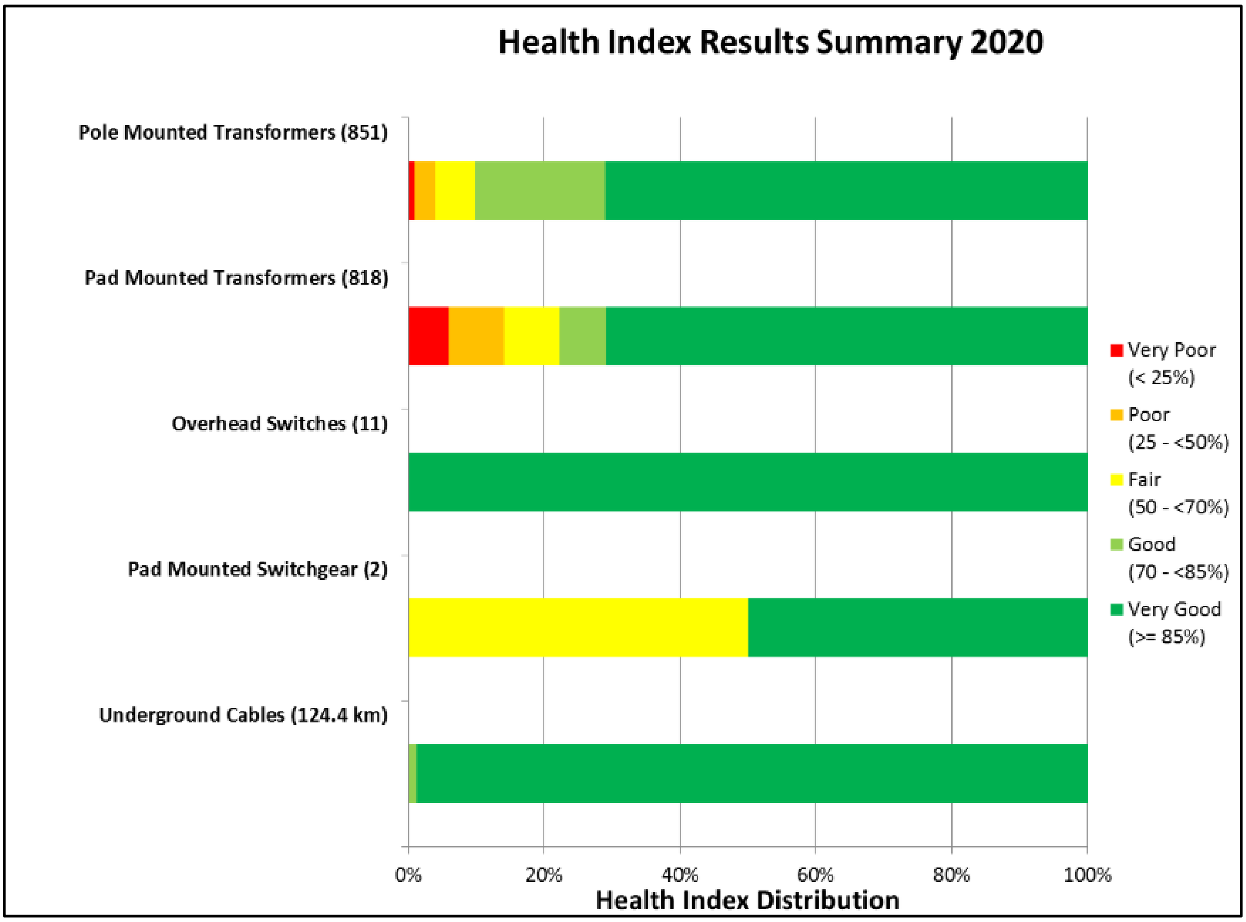


Figure 3: E.L.K. System Asset Condition Health Index

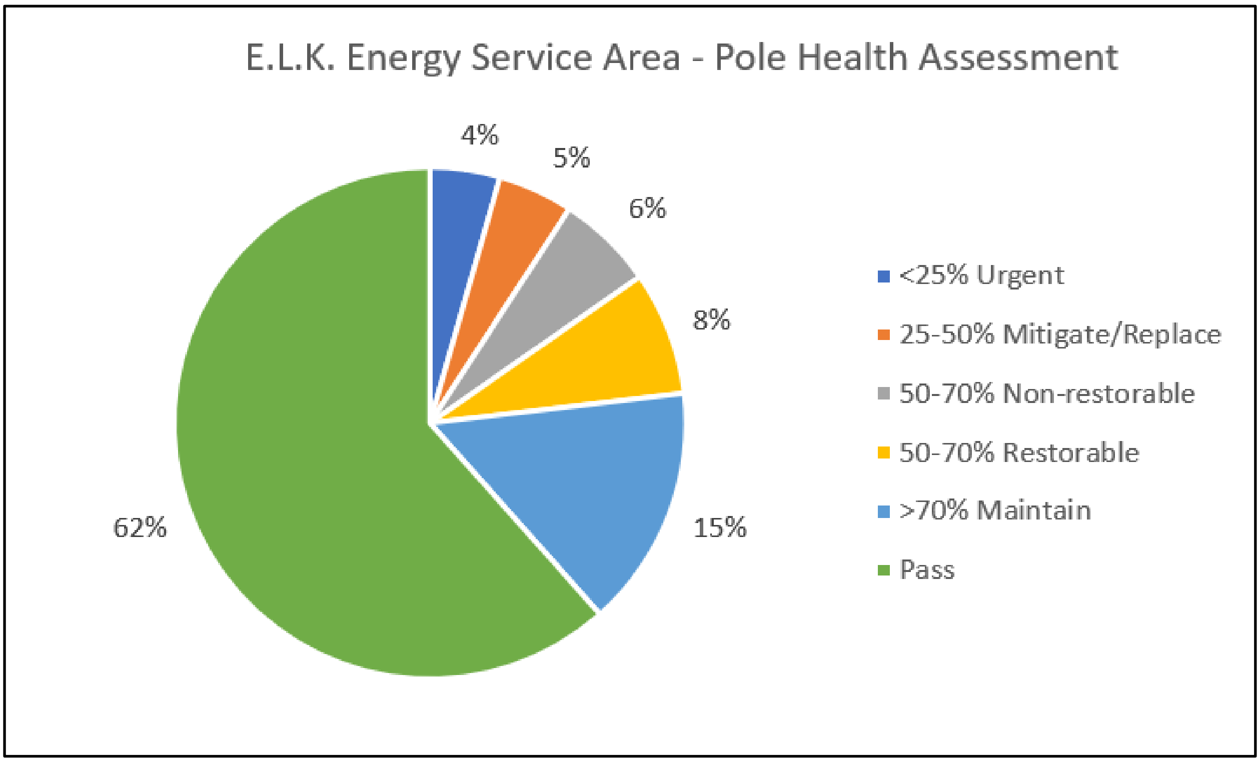


Figure 4: E.L.K. Energy pole inspection report results by service area

1. **Recognizing the conditions of E.L.K.'s asset base, please select one of the following options that best describes your preference towards how E.L.K. can be pacing their asset replacements over the next five years?**
   a. **The pace of System Renewal spending as specified within E.L.K.'s plan (which closely aligns to the average pace of System Renewal spending from the past 5-year period) is sufficient.**
   b. **E.L.K. should increase the pace of System Renewal spending such that assets in Very Poor and Poor condition, as well as assets past their useful life, are replaced on or before the start of the next 5-year period.**
   c. **E.L.K. should reduce the pace of System Renewal spending, which would mean not all poor and very poor assets would be addressed in the next five years, and this could result in more frequent and longer outages.**
   d. **Unsure.**

2. **Regarding system reliability performance, E.L.K. averaged 0.53 customer interruptions and 1.54 average hours of power disruption per year over the 2016-2020 period. Recognizing that E.L.K.'s proposed System Renewal investments will continue to manage system reliability performance over the next 5-year period, please select one**

of the following options that best describes your preferences with respect to system reliability performance:

a. **Continue to deliver the same level of system reliability performance as seen over the past 5-year period by executing the current DSP as presented by E.L.K..**
b. **Prioritize improvements to system reliability performance, thereby resulting in less customer outages per year with a reduced average outage duration, but with a potential increase to customer rates.**
c. **Deprioritize improvements that support system reliability performance, thereby resulting in more customer outages per year with an increased average outage duration, but with minimal impact to customer rates.**
d. **Unsure.**

General Plant

"General Plant" investments are focused on initiatives that support the 24/7 operations of E.L.K.'s distribution system, including upgrades to E.L.K.'s facilities and buildings that house employees and equipment, the replacement of critical fleet vehicles that transport crews to respond to outages, replacement and upgrades to critical IT hardware and software necessary to manage and analyze the system, as well as investments into operational technologies including new testing technologies to better monitor the performance of the grid.

E.L.K. has identified two key General Plant programs for implementation over the forecast period, a bucket truck replacement, and upgrades to IT. The procurement of the new bucket truck to replace the aging fleet would occur in Year 1 or 2 of the COS Application. Upgrades to IT infrastructure would result in the implementation of a Geographic Information Software (GIS) system, customer-friendly webpage updates, introduction of an outage map accessible to all customers, and purchase of new servers to support the digitization of E.L.K. records and information.

In the 2022-2026 DSP filing, E.L.K. is forecasting approximately $430k of General Plant spend per year, which is approximately 48% above the average pace of General Plant spend over the previous 5-year period from 2017-2021. The reason for the significant increase is due to the cost of the bucket truck, which accounts for XX% of the overall spend.

1. **Recognizing that General Plant investments allow for E.L.K.'s 24/7 operational backbone to be maintained, which of the following statements best represents your point of view?**

a. **The pace of General Plant spending as specified within E.L.K.'s 2022-2026 DSP is necessary to enable E.L.K. to continue operating in a fully functional and efficient manner.**
b. **E.L.K. should increase the pace of General Plant investments such that the utility can further enhance and accelerate utility efficiencies and operational improvements over the next 5-year period.**
c. **E.L.K. should reduce the pace of investments into aging IT, Fleet, and Operational Equipment, which will result in longer outage response times and increase inefficiencies within the utility.**
d. **Unsure.**

<u>System Operating & Maintenance (O&M) Expenditures</u>

Alongside their capital expenditure plan, E.L.K. executes pre-defined maintenance programs, which allow for assets to be maintained and/or repaired at regular intervals and allows for visual inspections to be executed such that condition-related information can be gathered to support the asset condition assessment process. E.L.K. continues to explore opportunities to further enhance maintenance practices, including but not limited to implementing scheduled visual inspection cycles from field crews, development of site inspection checklists, and scheduled vegetation management coordination and support from third-party vendors.

In the 2022-2026 DSP filing, E.L.K. is forecasting $XX of O&M spend per year, which is approximately XX% above the average pace of spend on O&M for the previous spend period from 2017-2021.

1. **Based on information provided in E.L.K.'s plan for System O&M expenditures, please select one of the following regarding your views on the levels of expenditures on System O&M:**
   a. **Agree**
   b. **Somewhat agree**
   c. **Neither agree nor disagree**
   d. **Somewhat disagree**
   e. **Disagree**

2. **Based upon your knowledge and understanding of E.L.K.'s overall DSP as communicated to you via this survey, which of the following statements best**

aligns to your overall opinion of E.L.K.'s DSP and associated investments in the next 5-year period?

a. **I believe that this is the right approach to continue to manage the safe and reliable performance of the system.**
b. **I'm not sure if this is the right approach but I trust E.L.K. as the expert to be able to make the right decisions.**
c. **I don't believe that this is the right approach and E.L.K. should consider revising their plans and strategy.**

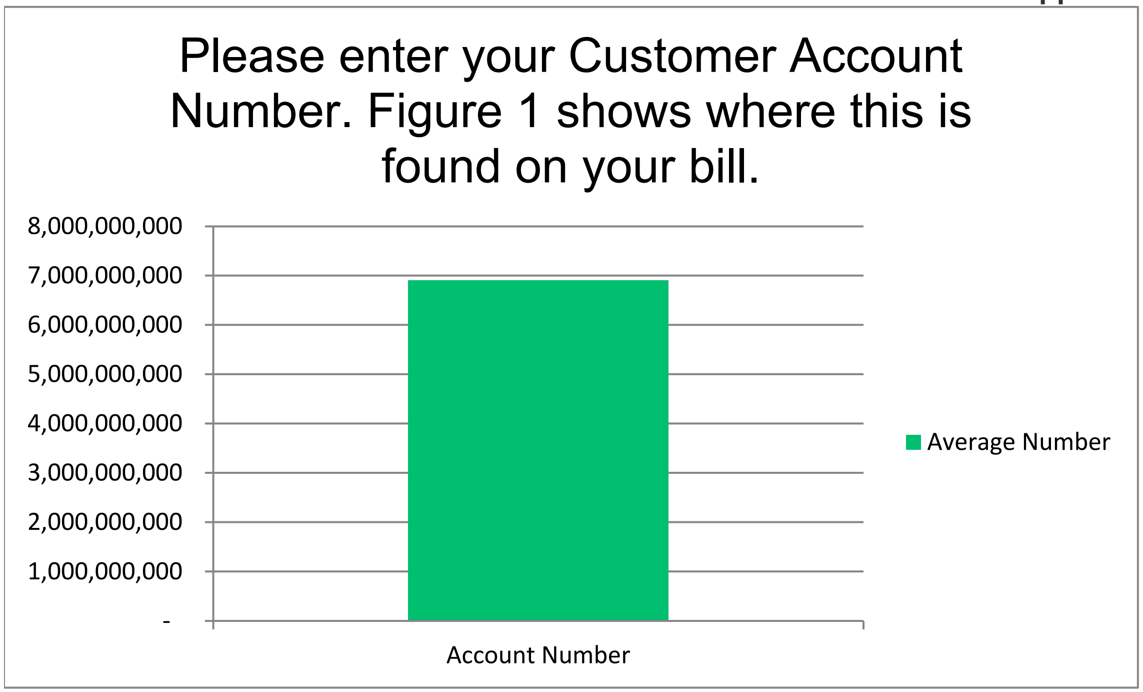
Thank you for your time and feedback.

7. Appendix B – Full Customer Survey Results

Customer Survey 2021

Please enter your Customer Account Number. Figure 1 shows where this is found on your bill.

Answer Choices	Average Number	Total Number	Responses	
Account Number	6,899,925,917	2,000,978,515,993	100.00%	290
			Answered	**290**
			Skipped	**0**



Customer Survey 2021

Please enter the account holder name.

Answered	**290**
Skipped	**0**

Customer Survey 2021

Please enter the contact phone number.

Answered	**290**
Skipped	**0**

Customer Survey 2021

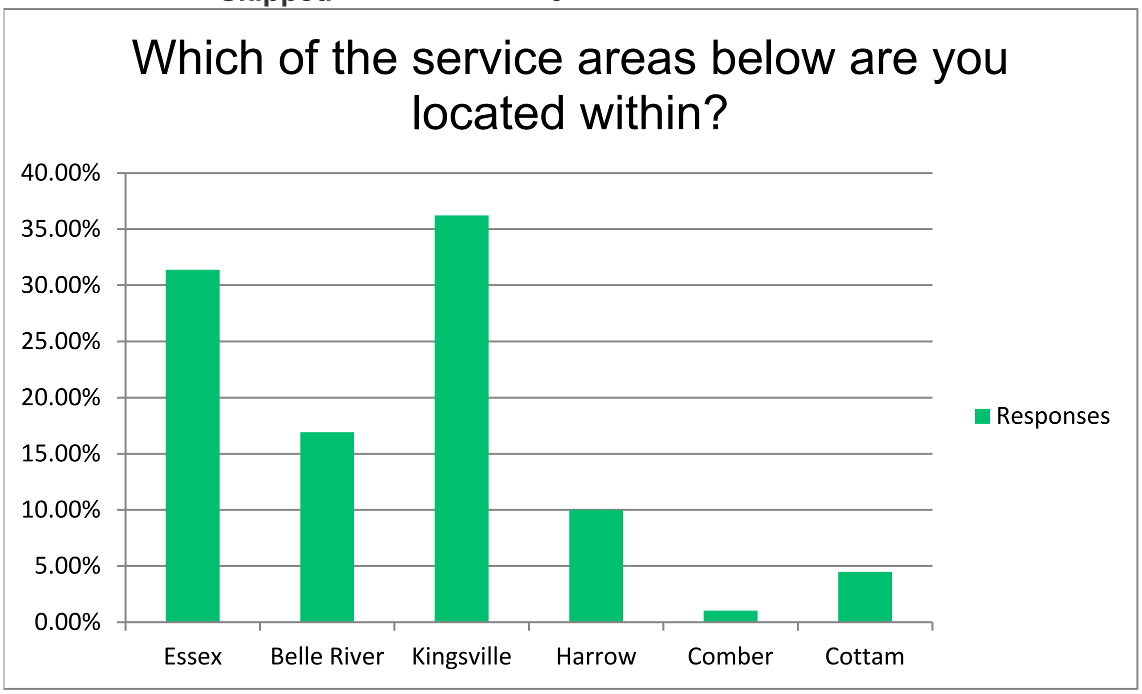
Are you a residential or business customer?

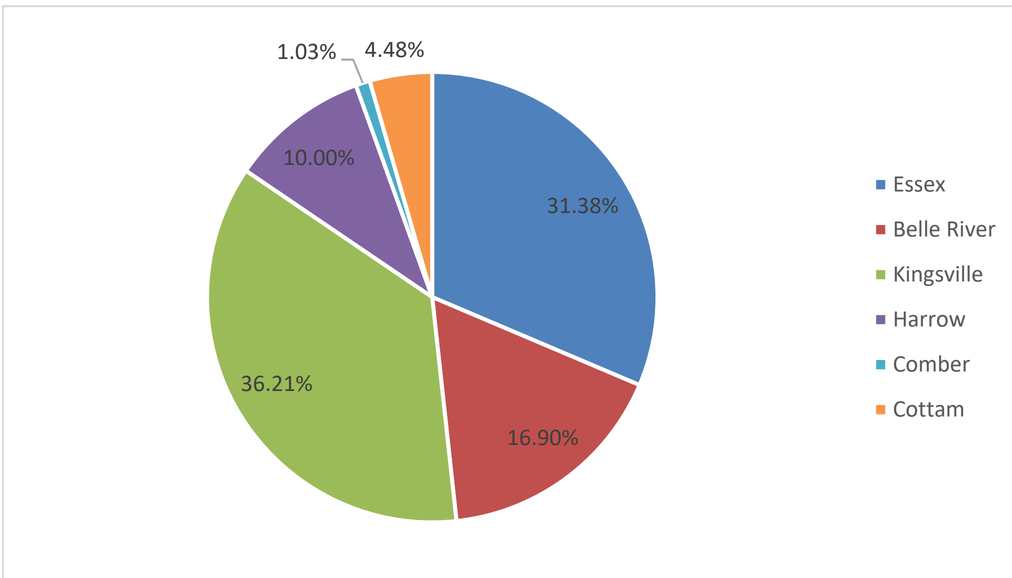
Answer Choices	Responses	
Residential	98.62%	286
Business	1.38%	4
	Answered	**290**
	Skipped	**0**

Customer Survey 2021

Which of the service areas below are you located within?

Answer Choices	Responses	
Essex	31.38%	91
Belle River	16.90%	49
Kingsville	36.21%	105
Harrow	10.00%	29
Comber	1.03%	3
Cottam	4.48%	13
	Answered	**290**
	Skipped	**0**




1.03%
4.48%
10.00%
31.38%
36.21%
16.90%
Essex
Belle River
Kingsville
Harrow
Comber
Cottam

Question 5

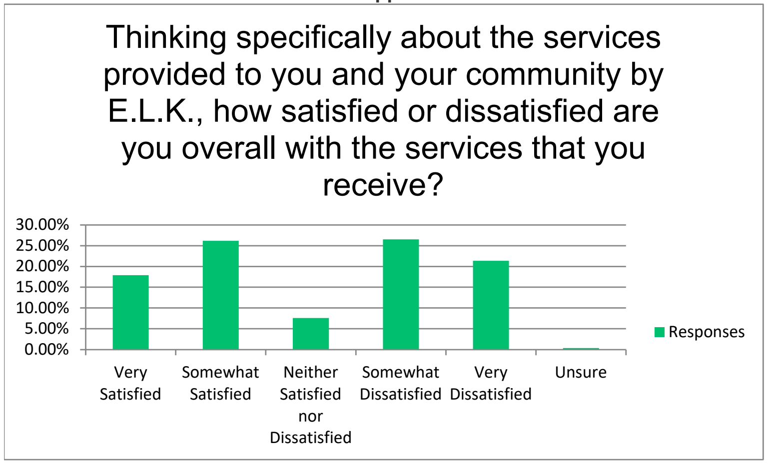
Customer Survey 2021

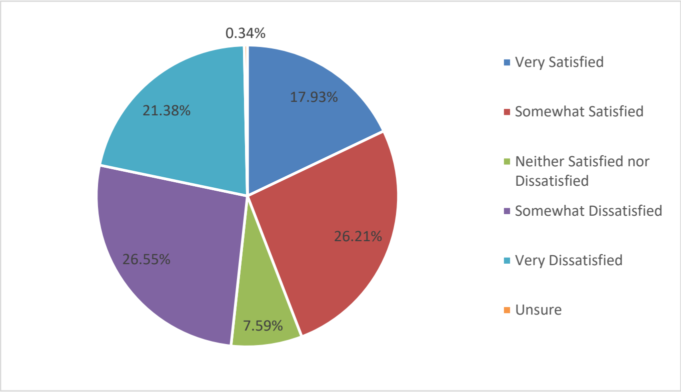
Thinking specifically about the services provided to you and your community by E.L.K., how satisfied or dissatisfied are you overall with the services that you receive?

Answer Choices	Responses	
Very Satisfied	17.93%	52
Somewhat Satisfied	26.21%	76
Neither Satisfied nor Dissatisfied	7.59%	22
Somewhat Dissatisfied	26.55%	77
Very Dissatisfied	21.38%	62
Unsure	0.34%	1
	Answered	**290**
	Skipped	**0**

Region Responses for Somewhat/Very Dissatisfied

Essex	49	
Belle River	11	
Kingsville	61	
Harrow	18	
Comber	0	
Cottam	0	
TOTAL	139	79.14%

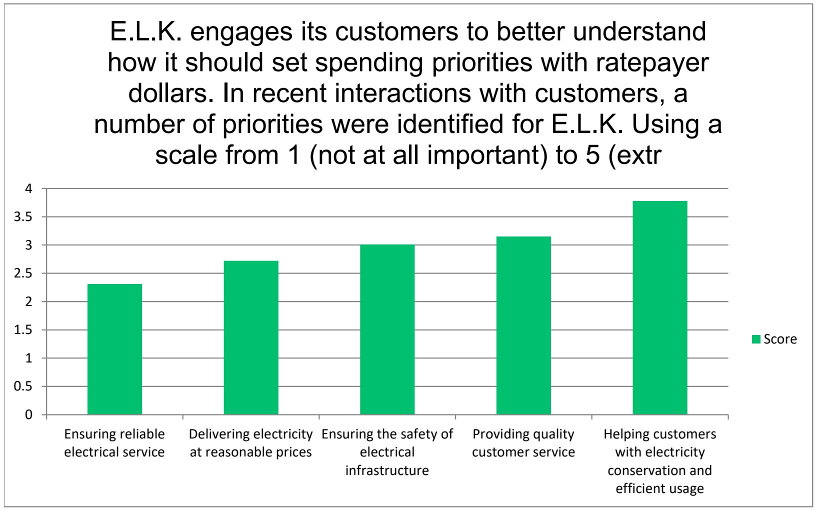




Customer Survey 2021

E.L.K. engages its customers to better understand how it should set spending priorities with ratepayer dollars. In recent interactions with customers, a number of priorities were identified for E.L.K. Using a scale from 1 (not at all important) to 5 (extremely important), please tell me how important each of the following E.L.K. Energy priorities are to you as a customer?

	1		2		3		4		5		Total	Score	
Ensuring reliable electrical service	20.21%	58	8.71%	25	4.18%	12	15.33%	44	51.57%	148	287	2.31	4.3
Delivering electricity at reasonable prices	9.72%	28	18.75%	54	20.83%	60	34.72%	100	15.97%	46	288	2.72	2.36
Ensuring the safety of electrical infrastructure	7.32%	21	26.48%	76	35.19%	101	22.30%	64	8.71%	25	287	3.01	2.16
Providing quality customer service	7.67%	22	34.15%	98	31.71%	91	18.82%	54	7.67%	22	287	3.15	2.04
Helping customers with electricity conservation and efficient usage	54.33%	157	11.76%	34	8.30%	24	9.00%	26	16.61%	48	289	3.78	1.48
											Answered	**290**	
											Skipped	**0**	



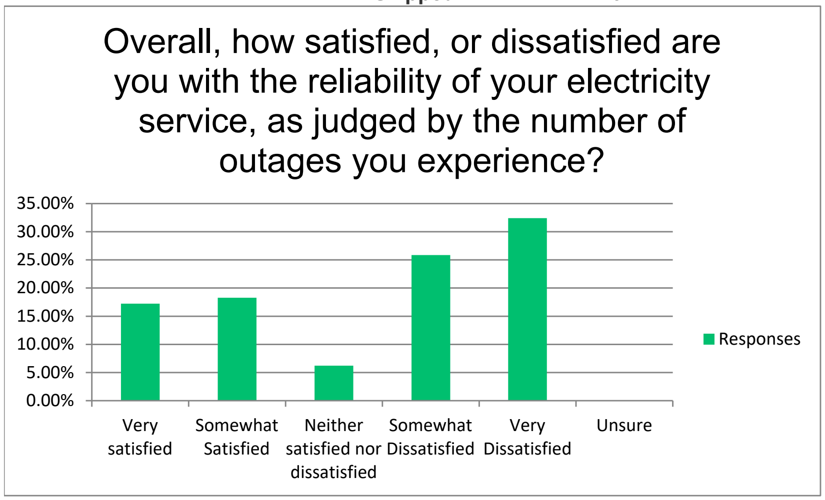
Customer Survey 2021

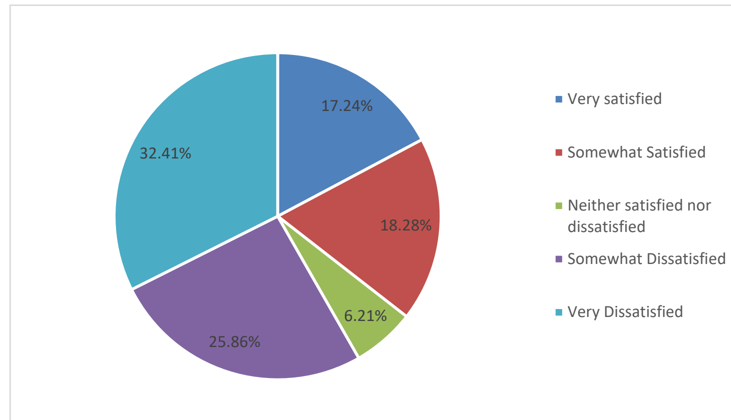
Overall, how satisfied, or dissatisfied are you with the reliability of your electricity service, as judged by the number of outages you experience?

Answer Choices	Responses	
Very satisfied	17.24%	50
Somewhat Satisfied	18.28%	53
Neither satisfied nor dissatisfied	6.21%	18
Somewhat Dissatisfied	25.86%	75
Very Dissatisfied	32.41%	94
Unsure	0.00%	0
	Answered	**290**
	Skipped	**0**

Region Responses for Somewhat/Very Dissatisfied

Essex	62	
Belle River	11	
Kingsville	74	
Harrow	21	
Comber	0	
Cottam	1	
TOTAL	169	80.5%

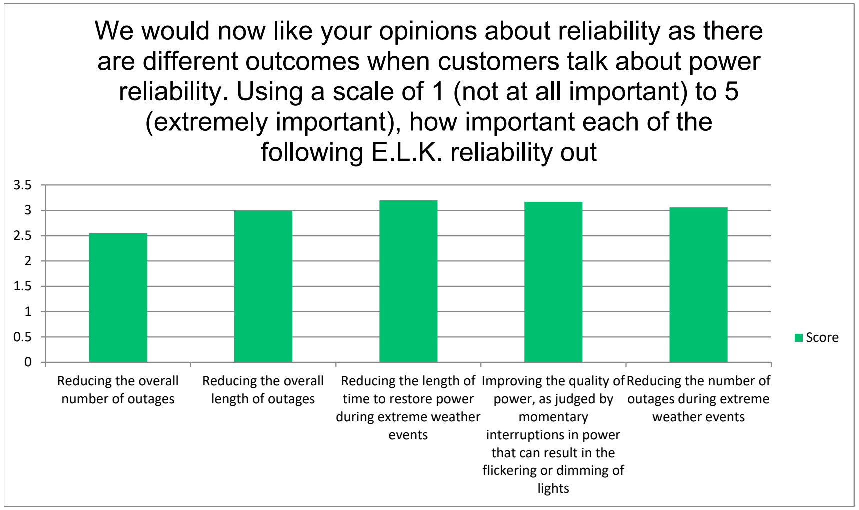


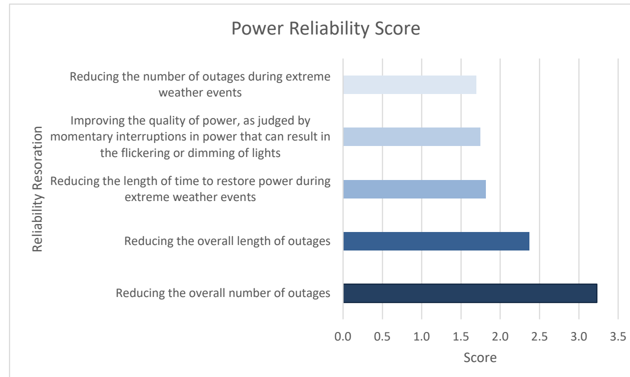


Customer Survey 2021

We would now like your opinions about reliability as there are different outcomes when customers talk about power reliability. Using a scale of 1 (not at all important) to 5 (extremely important), how important each of the following E.L.K. reliability outcomes to you as a customer?

	1		2		3		4		5		Total	Score	
Reducing the overall number of outages	22.22%	64	11.81%	34	8.33%	24	14.24%	41	43.40%	125	288	2.55	3.2
Reducing the overall length of outages	8.01%	23	21.25%	61	39.72%	114	24.04%	69	6.97%	20	287	2.99	2.37
Reducing the length of time to restore power during extreme weathe	15.57%	45	29.41%	85	22.15%	64	25.26%	73	7.61%	22	289	3.2	1.82
Improving the quality of power, as judged by momentary interruption	35.29%	102	11.76%	34	11.07%	32	17.99%	52	23.88%	69	289	3.17	1.74
Reducing the number of outages during extreme weather events	18.34%	53	25.26%	73	18.69%	54	19.03%	55	18.69%	54	289	3.06	1.69
											Answered	**290**	
											Skipped	**0**	

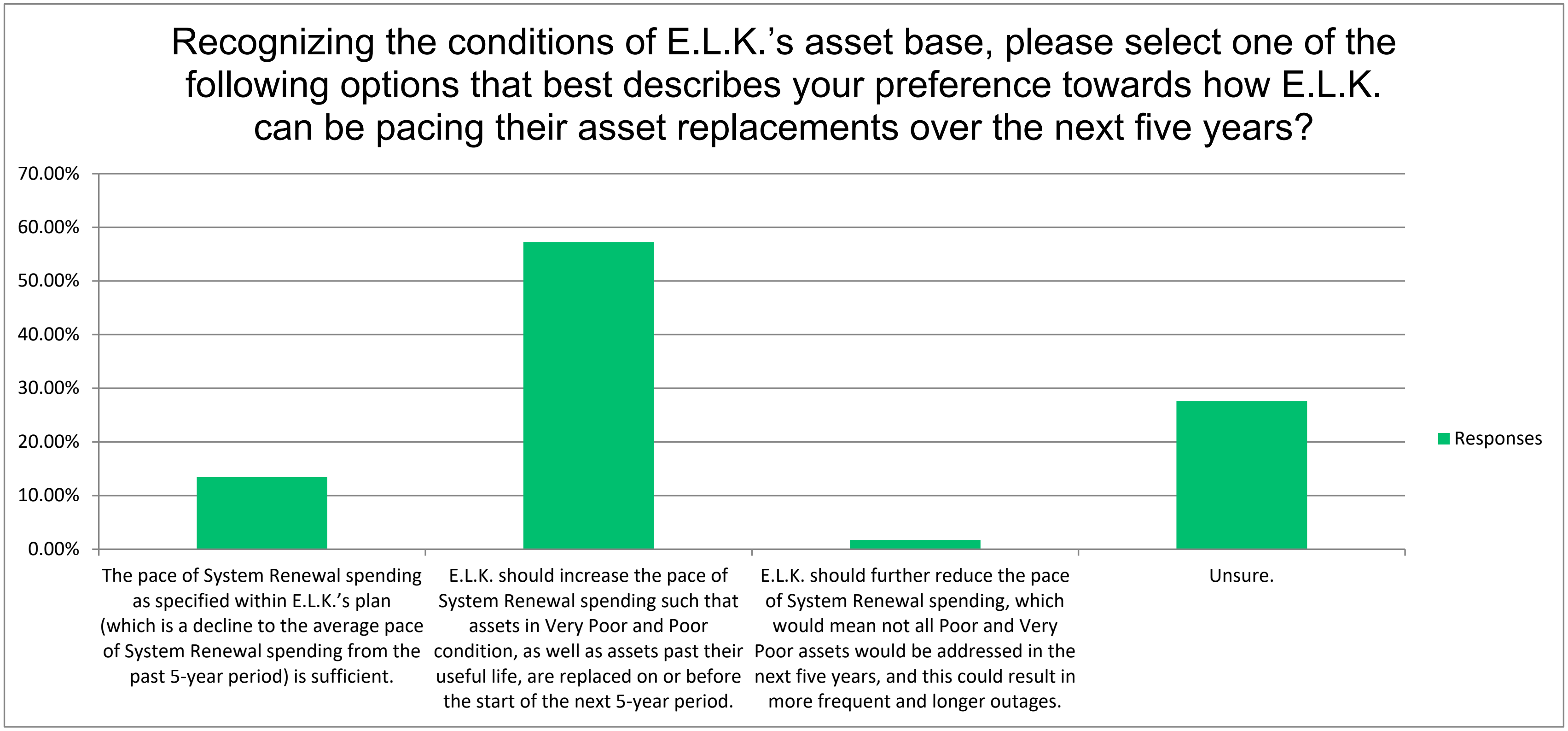




Customer Survey 2021

Recognizing the conditions of E.L.K.'s asset base, please select one of the following options that best describes your preference towards how E.L.K. can be pacing their asset replacements over the next five years?

Answer Choices	Responses	
The pace of System Renewal spending as specified within E.L.K.'s plan (which is a decline to the average pace of System Renewal spending from the past 5-year period) is sufficient.	13.45%	39
E.L.K. should increase the pace of System Renewal spending such that assets in Very Poor and Poor condition, as well as assets past their useful life, are replaced on or before the start of the next 5-year period.	57.24%	166
E.L.K. should further reduce the pace of System Renewal spending, which would mean not all Poor and Very Poor assets would be addressed in the next five years, and this could result in more frequent and longer outages.	1.72%	5
Unsure.	27.59%	80
	Answered	**290**
	Skipped	**0**

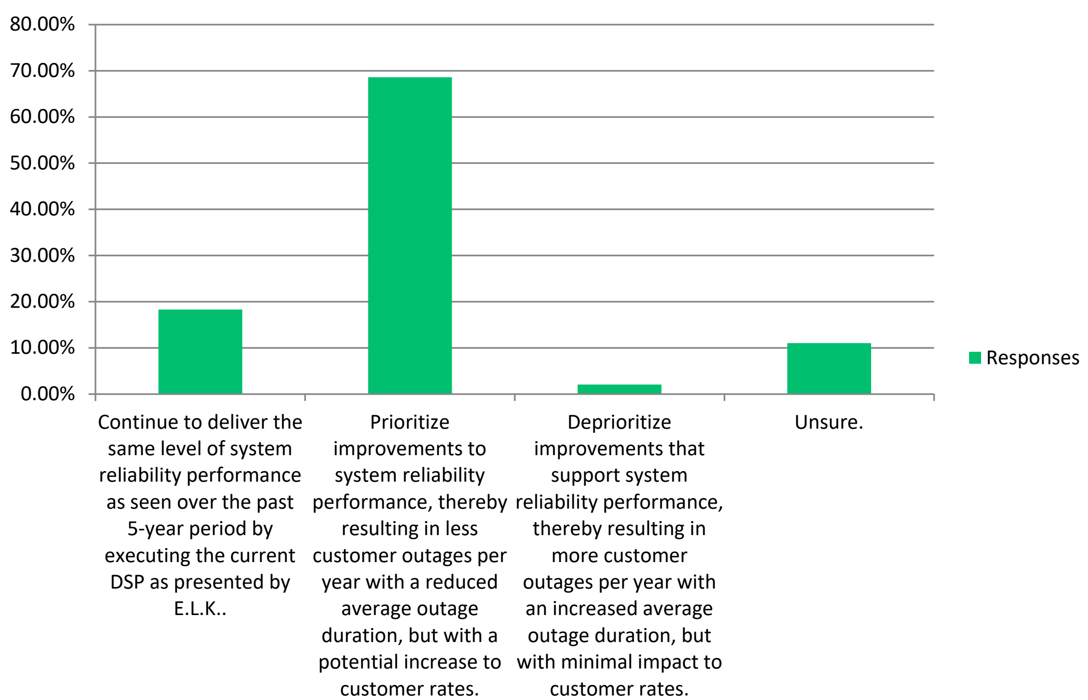


Customer Survey 2021

Regarding system reliability performance, E.L.K. averaged 0.53 customer interruptions and 1.54 average hours of power disruption per year over the 2016-2020 period. Recognizing that E.L.K.'s proposed System Renewal investments will continue to manage system reliability performance over the next 5-year period, please select one of the following options that best describes your preferences with respect to system reliability performance:

Answer Choices	Responses	
Continue to deliver the same level of system reliability performance as seen over the past 5-year period by executing the current DSP as presented by E.L.K..	18.28%	53
Prioritize improvements to system reliability performance, thereby resulting in less customer outages per year with a reduced average outage duration, but with a potential increase to customer rates.	68.62%	199
Deprioritize improvements that support system reliability performance, thereby resulting in more customer outages per year with an increased average outage duration, but with minimal impact to customer rates.	2.07%	6
Unsure.	11.03%	32
	Answered	**290**
	Skipped	**0**

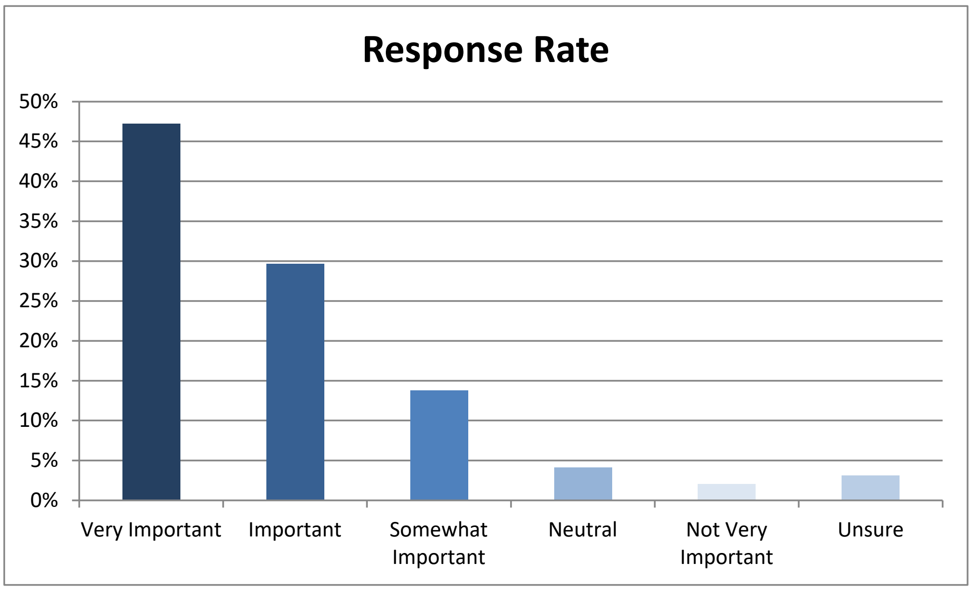
Regarding system reliability performance, E.L.K. averaged 0.53 customer interruptions and 1.54 average hours of power disruption per year over the 2016-2020 period. Recognizing that E.L.K.'s proposed System Renewal investments will continue to manage syst



Customer Survey 2021

As the E.L.K. community continues to grow, how important do you think it is that E.L.K. upgrade software and systems to support customer service like GIS, outage management including outage maps, billing and communications, and functional services?

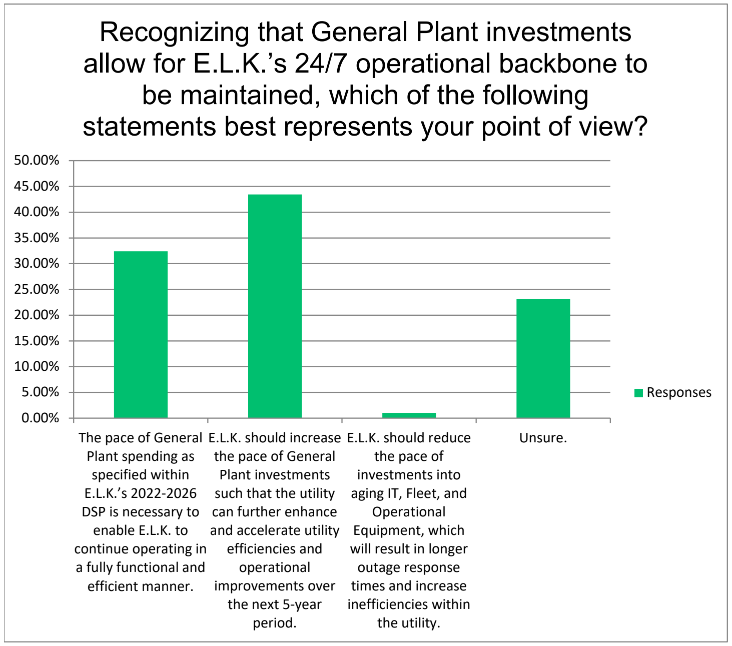
Answer Choices	Response Rate	
Very Important	47%	137
Important	29.66%	86
Somewhat Importan	13.79%	40
Neutral	4.14%	12
Not Very Important	2.07%	6
Unsure	3.10%	9
	Answered	**290**
	Skipped	**0**

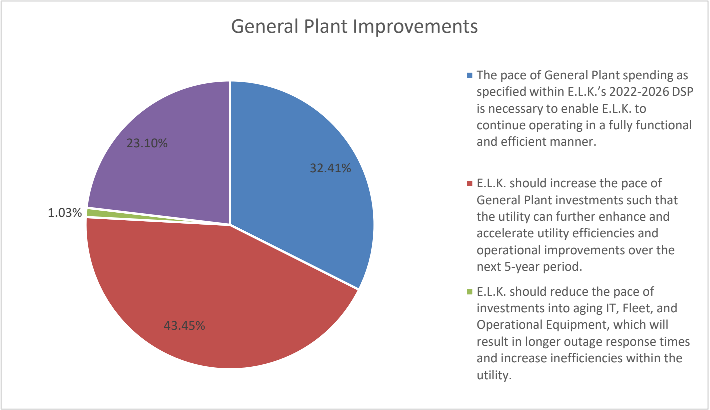


Customer Survey 2021

Recognizing that General Plant investments allow for E.L.K.'s 24/7 operational backbone to be maintained, which of the following statements best represents your point of view?

Answer Choices	Responses	
The pace of General Plant spending as specified within E.L.K.'s 2022-2026 DSP is necessary to enable E.L.K. to continue operating in a fully functional and efficient manner.	32.41%	94
E.L.K. should increase the pace of General Plant investments such that the utility can further enhance and accelerate utility efficiencies and operational improvements over the next 5-year period.	43.45%	126
E.L.K. should reduce the pace of investments into aging IT, Fleet, and Operational Equipment, which will result in longer outage response times and increase inefficiencies within the utility.	1.03%	3
Unsure.	23.10%	67
	Answered	**290**
	Skipped	**0**

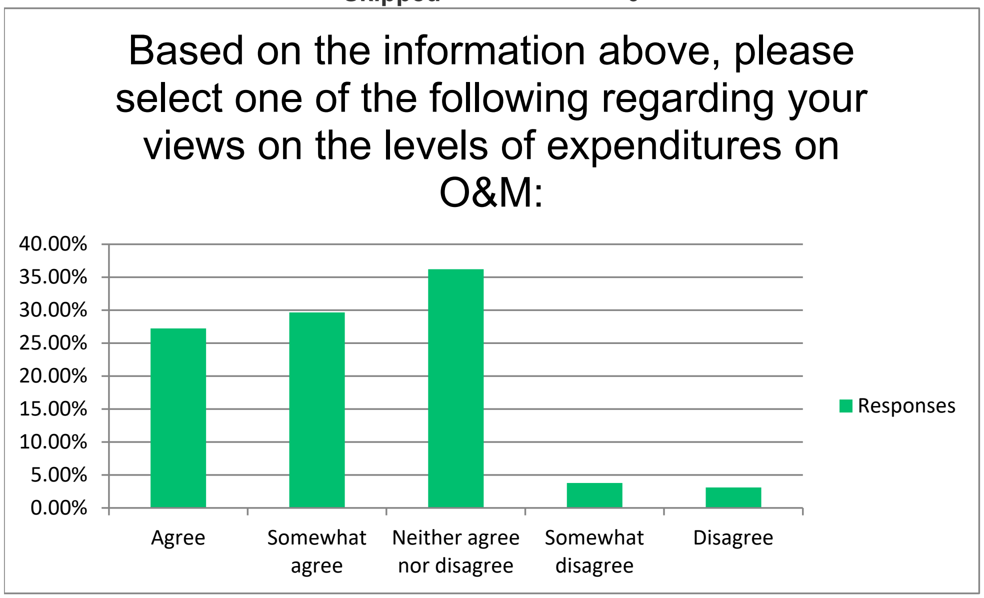




Customer Survey 2021

Based on the information above, please select one of the following regarding your views on the levels of expenditures on O&M:

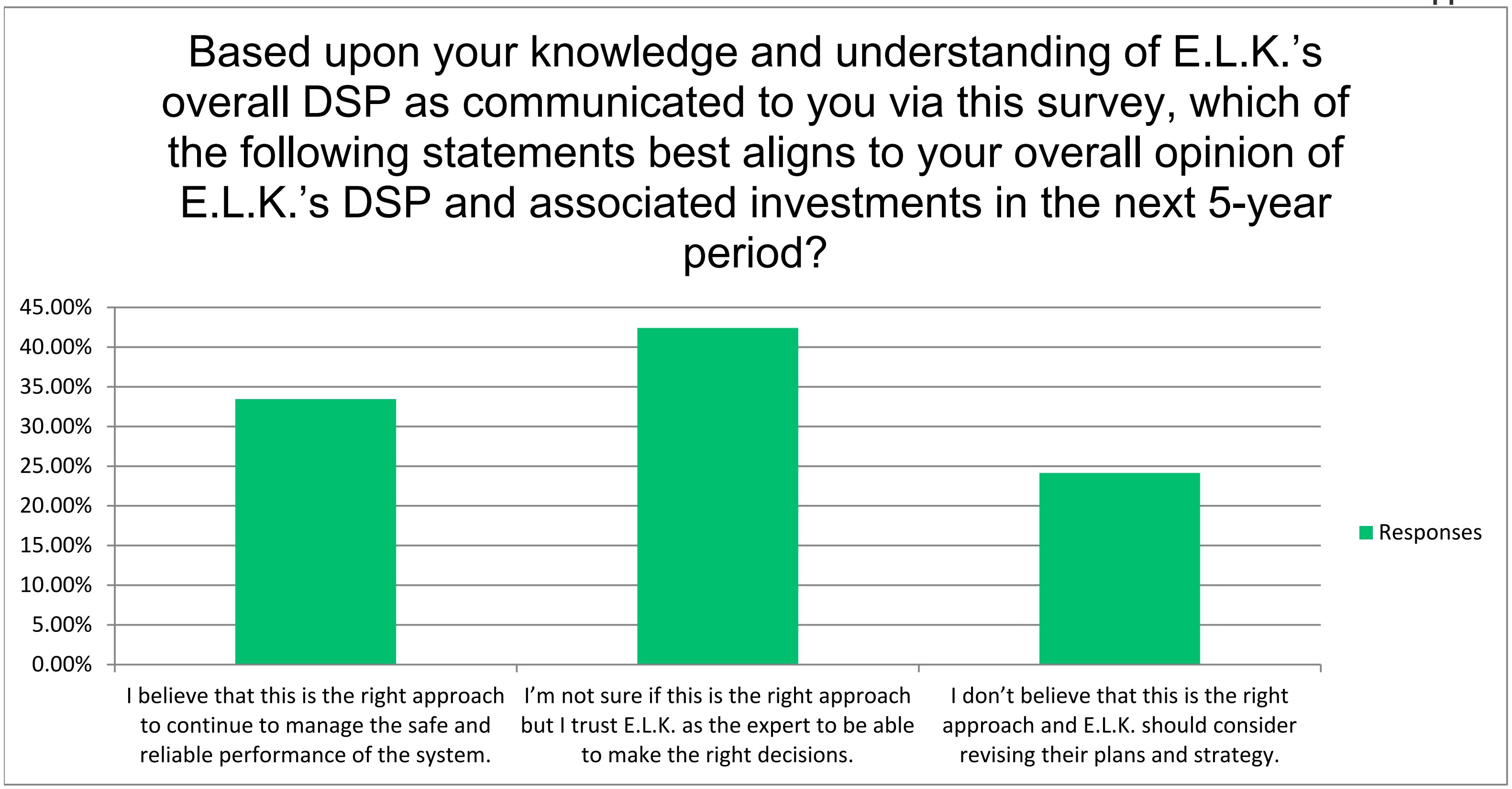
Answer Choices	Responses	
Agree	27.24%	79
Somewhat agree	29.66%	86
Neither agree nor disagree	36.21%	105
Somewhat disagree	3.79%	11
Disagree	3.10%	9
	Answered	**290**
	Skipped	**0**



Customer Survey 2021

Based upon your knowledge and understanding of E.L.K.'s overall DSP as communicated to you via this survey, which of the following statements best aligns to your overall opinion of E.L.K.'s DSP and associated investments in the next 5-year period?

Answer Choices	Responses	
I believe that this is the right approach to continue to manage the safe and reliable performance of the system.	33.45%	97
I'm not sure if this is the right approach but I trust E.L.K. as the expert to be able to make the right decisions.	42.41%	123
I don't believe that this is the right approach and E.L.K. should consider revising their plans and strategy.	24.14%	70
	Answered	**290**
	Skipped	**0**



Question 15

Customer Survey 2021

Do you have any general comments or feedback for E.L.K.?

Answered	**152**
Skipped	**138**

Customer Survey 2021

Skill Testing Question What is the answer to the following equation? (6 + 24) / 2

Answered	**290**
Skipped	**0**

APPENDIX D – 2017 WINDSOR-ESSEX NEEDS ASSESSMENT REPORT

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

Windsor-Essex Region

Date: October 24, 2017

Prepared by: Windsor-Essex Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the Windsor-Essex Region and to recommend which needs may require further assessment and/or regional coordination. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable 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	Windsor-Essex		
LEAD	Hydro One Networks Inc. ("HONI")		
START DATE	June 29, 2017	**END DATE**	October 24, 2017

1. INTRODUCTION

The first cycle of the regional planning process in the Windsor-Essex region was completed in 2015, with an Integrated Regional Resource Plan (IRRP) published in April 2015, followed by the publication of the Windsor-Essex Regional Infrastructure Plan (RIP) in December 2015. The RIP provided a summary of needs identified in the region through the IRRP process and provided further details regarding the wires plans identified to address the near-term and mid-term needs. The RIP also identified some long-term needs that will be reviewed during this planning cycle.

2. REGIONAL ISSUE/TRIGGER

In accordance with the regional planning process, a regional planning cycle should be triggered every five years, or less if there is emerging needs. This NA was triggered as the result of significant load growth and a new load forecast in the Kingsville-Leamington area, largely driven by expansion in the greenhouse sector, which may require changes to the existing recommended plans as set out in the previous RIP (December 2015), and/or development of new plans.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment covers the Windsor-Essex region, and includes:

- Identification of new needs based on updated information provided by the Study Team in the context of the ongoing work for the region being implemented as a result of the previous cycle and
- Confirmation of scope and timing of plans identified in the previous planning cycle in the IRRP and RIP.

The Study Team may also re-examine 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 which may impact the magnitude or timing of the needs.

4. INPUTS/DATA

The Study Team, including representatives from Local Distribution Companies (LDCs), the Independent Electricity System Operator (IESO), and Hydro One (lead transmitter), provided inputs and any relevant information for the Windsor-Essex region regarding system reliability, capacity needs, operational issues, and major assets/facilities approaching end-of-life essential for regional planning.

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify the electrical needs in the region over the study period (2017-2026). The assessment reviewed available information including historical loading, future load forecast, forecast impacts of planned conservation and demand management (CDM) programs, expected distributed generation (DG) capacity based on existing contracts, system reliability and operation issues in the region along with major high voltage equipment identified to be at the end of their useful life and requiring replacement/refurbishment.

6. RESULTS

Based on the new and updated information, a summary of the results of this Needs Assessment is provided below:

Autotransformer and Transmission Line Capacity Needs

- The 230/115kV autotransformers at Keith TS and Lauzon TS, providing supply to the J3E/J4E subsystem, are adequate over the study period for the loss of a single autotransformer based on available information on load growth and installed/contracted generation.

- The 230kV and 115kV transmission lines in the region are adequate over the study period for the loss of a single circuit based on available information on load growth and installed/contracted generation.

Station Capacity Needs

- **Kingsville TS**
  - As a result of significant load growth in the Kingsville-Leamington area, the peak load at Kingsville TS is expected to reach 73MW (in the summer) and 100MW (in the winter) within the next 5 years. This would exceed the Kingsville TS LTR, if the 4x42 MVA station were to be downsized to a 2x42MVA station in 2018 as per the 2015 RIP plan.
  - In light of this new information, Hydro One and the LDC (Hydro One Distribution) have agreed that larger standard size units (2x83MVA) should be used. The sustainment work is expected to be completed in 2019, and therefore no further action is required to address Kingsville TS capacity need.

- **Belle River TS** and **Lauzon TS (T5/T6 DESN)** could exceed their station supply capacity within the study period if the effects of installed capacitor banks are not considered.

- **Leamington TS** could exceed the station winter supply capacity within the study period when the effect of installed capacitor banks is not considered. The station winter peak may occur at a time of high voltages in the broader region which may prevent the deployment of the capacitor banks. Further study is required for Leamington TS winter capacity need.

Load Restoration Needs

- With the incorporation of Leamington TS in 2018 and the transfer of load from Kingsville TS to the new station, the system meets the requirement to restore power within 8 hours to customers in the J3E/J4E subsystem at peak times following the loss of circuits C23Z/C24Z. Based on the updated demand forecast, by the year 2026 up to 40MW of the interrupted load will remain to be restored through maintenance crew work or recall of existing outage. This is expected to be accomplished within 8 hours of the initial contingency and hence meet the ORTAC restoration requirement. The amount of load requiring maintenance crew work for restoration is expected to increase in the long-term considering expiration of existing generation contracts in the next 10-15 years.

- Load restoration requirement for C21J/C22J, K2Z/K6Z, and Z1E/Z7E contingencies is expected to be met over the study period. With the incorporation of Leamington TS in 2018, post-contingency load transfers would be made to reduce the amount of load requiring maintenance crew work for restoration to below 150 MW. This balance of load is expected to be restored within 8 hours of the initial contingency and hence meet the ORTAC requirement for load restoration.

System Operational Issues

For the purposes of the Needs Assessment, the IESO identified issues related to overvoltage or thermal overload for select breaker failure and multiple element contingencies. The IESO will conduct a separate bulk planning study to determine if these events warrant changes to the Windsor Area Remedial Action Scheme to ensure the system can adequately handle these low probability events.

Aging Infrastructure

- End-of-life assets have been identified at the following stations: Kingsville TS (T1/T2/T3/T4 Transformers), Keith TS (Auto-Transformer), Crawford TS (T3 Transformer), Lauzon TS (T1/T2 Autotransformers, T6/T7 Step Down Transformers), and Malden TS (LV Breakers)

Previously Identified Needs

The following needs were identified in the previous regional planning cycle, and the recommended action should continue:

- Supply to Essex County Transmission Reinforcement (SECTR)
- 230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project
- Additional feeder position at Malden TS
- Decommission of Tilbury TS and transfer of serviced load to a different supply point
- Decommission of T1 Transformer at Keith TS
- Replacement and upsizing of the Keith autotransformers to 250 MVA units[1]

7. RECOMMENDATIONS

The Study Team recommendations are as follows:

[1] Recent discussion between Hydro One and the IESO have confirmed that the previously identified need to replace the Keith autotransformers should be used as an opportunity to upsize the units based on their current utilization and known information about installed/contracted generation and load in the region.

a) Hydro One and relevant LDCs will develop an implementation plan for the following needs:
   - Replacement /refurbishment of EOL station equipment at Kingsville TS, Crawford TS, Malden TS, and Keith TS with similar type of equipment with same or higher ratings.
   - Station capacity needs at Kingsville TS, by replacing transformers with 2x83MVA units (as planned) to provide sufficient capacity over the study period.

b) Station capacity needs identified at Belle River TS and Lauzon TS (T5/T6 DESN) have been confirmed to be addressed by existing capacitor banks. No further investments are required.

c) Further assessment is required for the following needs via the coordinated regional planning process:
   - Station capacity need identified for Leamington TS if capacitor banks are not deployed.
   - Long-term restoration need for J3E/J4E subsystem for the loss of the circuits from Chatham to Lauzon.
   - Potential mid- to long-term load restoration needs for C21J/C22J, K2Z/K6Z, and Z1E/Z7E contingencies.
   - Sustainment needs at Lauzon TS which may lead to configuration changes/non-like-for-like replacement.

d) The IESO will undertake a bulk system study to further assess any changes that maybe needed to the Windsor Area Remedial Action Scheme to respect certain breaker failure or multiple element contingencies which may result in overvoltage or thermal overload.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

The first cycle of the regional planning process in the Windsor-Essex region was completed in December 2015, with the publication of the Windsor-Essex Regional Infrastructure Plan (“RIP”). The RIP provides description of the identified needs and recommendations of preferred wires plans to address near-term and mid-term needs. The RIP also identified some long-term needs that will be reviewed during this planning cycle.

The purpose of this Needs Assessment (“NA”) is to identify new needs, and confirm the needs and/or plans identified in the previous planning cycle. Since the first regional planning cycle, several new needs in the region have been identified. The majority of these needs are a result of load growth in the Kingsville-Leamington area which needs to be addressed over the next 10 years period.

This report captures the results of the assessment based on input provided by the Windsor-Essex Study Team listed below.

Table 1. Windsor-Essex Study Team Participants

Company
Hydro One Networks Inc. (Lead Transmitter)
Independent Electricity System Operator (“IESO”)
E.L.K. Energy Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Essex Powerlines Corporation
Hydro One Networks Inc. (Distribution)

2 REGIONAL ISSUE/TRIGGER

In accordance with the regional planning process, the regional planning cycle should be triggered at least every five years, or when a new need emerges. This NA was triggered as the result of significant forecast load growth in the Kingsville-Leamington area, largely driven by expansion in the greenhouse sector.

The load at Kingsville TS was expected to be maintained under 50 MW as indicated in the previous RIP. Load beyond this limit would be transferred to the new Leamington TS (expected in-service date 2018). However, the recent load forecast updates provided by the LDCs shows that load in the Kingsville-Leamington area is growing significantly faster, and will become winter-peaking from 2019, as shown below. In particular, the Kingsville TS load will be well over the previously planned limit. This therefore negates the previous plan to downsize the station to 2 x 42 MVA transformers.

Table 2. Kingsville-Leamington Area Load Forecast Comparison (Year 2019 Net)

Station	Old Load Forecast	New Load Forecast	
		Summer	Winter
Kingsville TS	Limited to 50 MW	82	110
Leamington TS	107	133	139

3 SCOPE OF NEEDS ASSESSMENT

The scope of this Needs Assessment includes:

- Identification of new needs based on latest information provided by the Study Team, and
- Confirmation of existing needs and/or plans identified in the previous planning cycle.

The Study Team determined that a comprehensive update of the load forecast is necessary for the second cycle due to greenhouse and grow light expansion in the Kingsville-Leamington area. The LDCs were requested to provide an update for all stations and is provided in Appendix A. The updated load forecast will be taken into account during the next phases of regional planning, i.e. SA, Integrated Regional Resource Plan ("IRRP") and RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The Windsor-Essex Region comprises the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. The map of the region is shown in Figure 1 below.

The region's 115kV network connects to the 230kV transmission system at Keith TS and Lauzon TS via two auto-transformers in each station. About 60% of the area load is supplied by fourteen step-down transformer stations connected to the 115kV network, while the balance is supplied by three step-down transformer stations connected to the 230kV network.

The transmission system in the region can be divided into two "nested" subsystems:

- The Kingsville-Leamington subsystem: customers supplied from Kingsville TS and Leamington TS
- The J3E-J4E subsystem: customers supplied from stations connected to the Windsor-Essex 115 kV system, as well as customers supplied from the 230/27.6 kV Lauzon DESN.

As can be noted in Figure 2 below, the Kingsville-Leamington subsystem is nested within the J3E-J4E subsystem. Therefore, increasing supply to the Kingsville-Leamington subsystem or transferring load from the existing Kingsville TS to a new 230 kV TS will impact the supply and demand balance in the J3E-J4E subsystem.

Most of the load growth in the region is in the Kingsville-Leamington area and is largely driven by expansion in the greenhouse sector and the expanded use of grow light in the sector. The consequence of this use of grow light is that both Kingsville TS and Leamington TS will become winter peaking stations as per the load forecast (Appendix A).

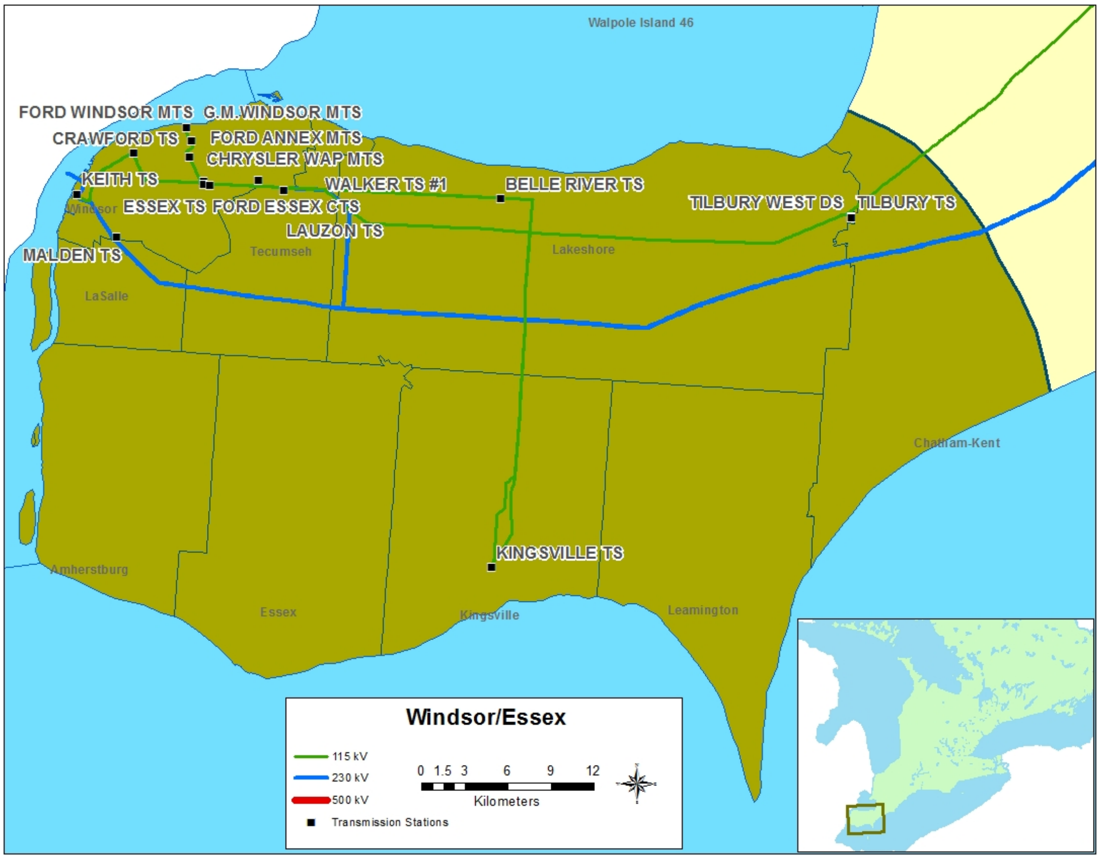


Figure 1. Geographical Map of Windsor-Essex Region

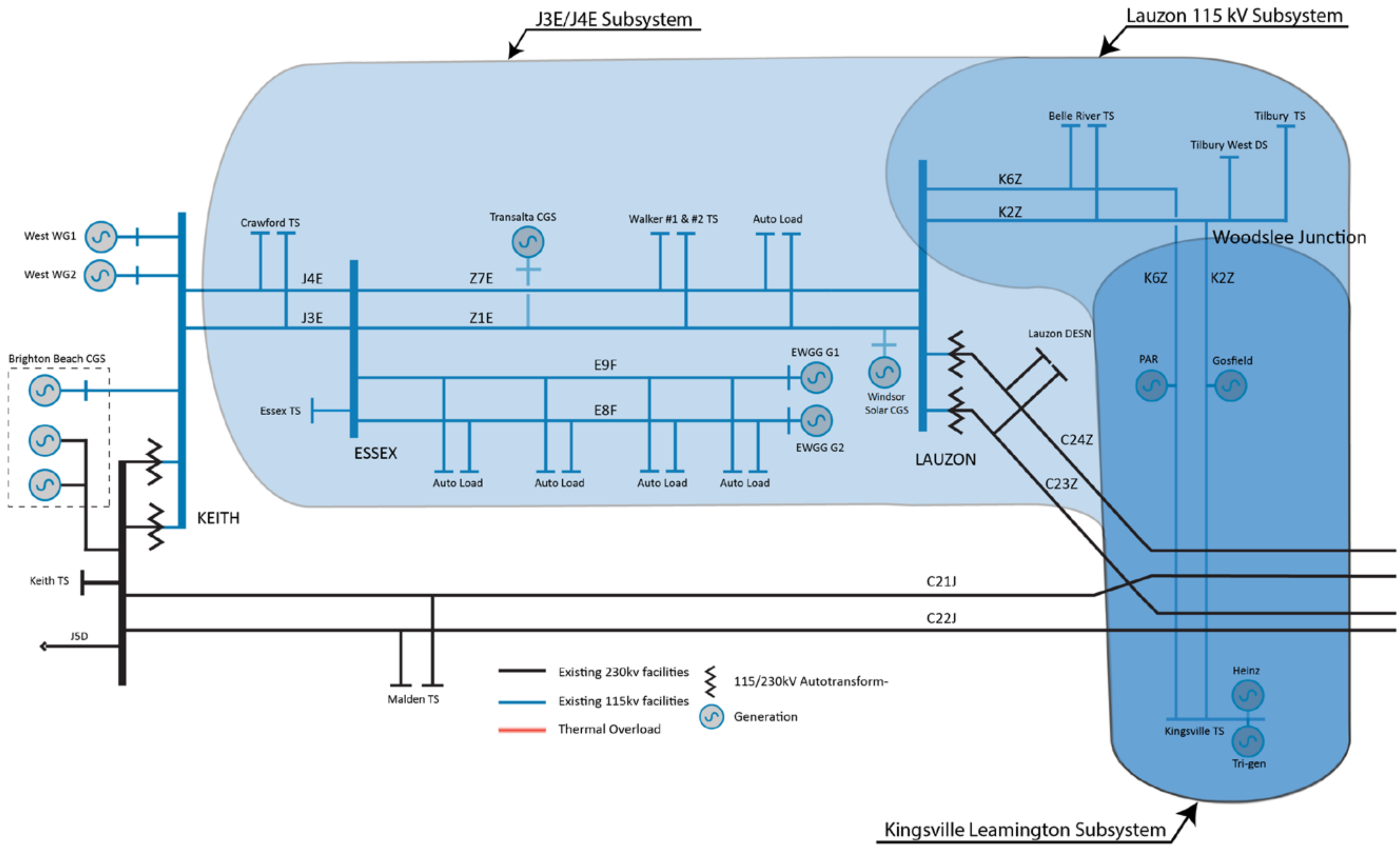


Figure 2. Windsor-Essex Region Subsystems/Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, and Hydro One provided information and input for the Windsor-Essex Region NA. The information provided includes the following:

- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and,
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the Windsor-Essex Region.

6 ASSESSMENT METHODOLOGY

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

Information gathering included:

i. New Load forecast was developed in view of the additional load growth.

ii. Relevant information regarding system reliability and operational issues in the region.

iii. List of major HV transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life relevant for regional planning purposes. This includes HV transformers, autotransformers, HV Breakers, HV underground cables and overhead lines.

Technical assessment of needs is based on:

i. Station capacity and Transmission Adequacy Assessment.

   a. The assessment is based on summer and winter peak loads. The study period for the adequacy assessment is 2017-2026.
   b. 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.
   c. Normal planning supply capacity for Hydro One transformer stations in this Region is determined by the summer 10-Day Limited Time Rating (LTR).

ii. System reliability and operation assessment.

iii. End-of-life equipment: high-level assessment with respect to replacing equipment with similar type versus higher rating /downsizing/elimination of equipment or maintaining status quo.

7 RESULTS

This section summarizes the results of the Needs Assessment in the Windsor-Essex region.

7.1 Transmission System Capacity Needs

The 230/115kV autotransformers at Keith TS and Lauzon TS, providing supply to the J3E/J4E subsystem, are adequate based on existing transformers over the study period for the loss of a single autotransformer.

The 230kV and 115kV transmission lines in the region are adequate over the study period for the loss of a single circuit.

These assessments were conducted based on current load forecast for the region and information on installed/contracted generation.

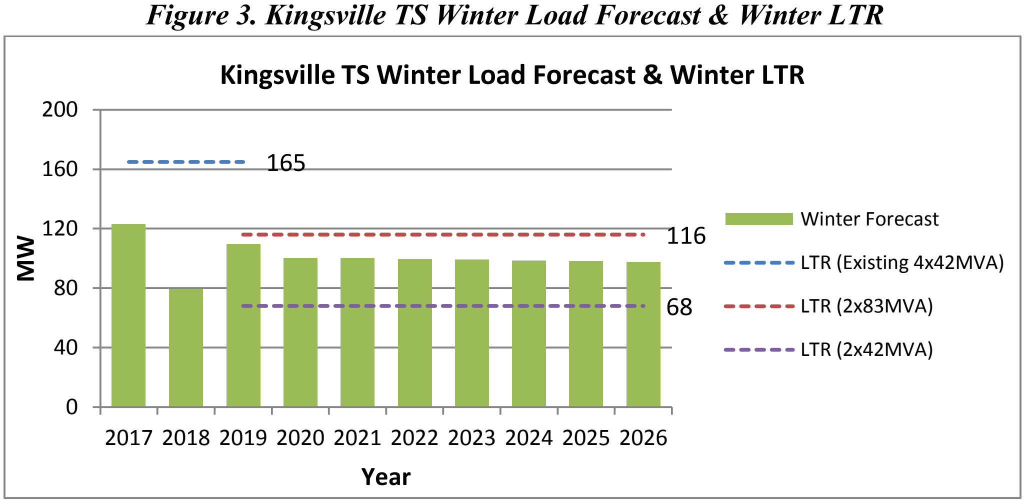
7.2 Transformer Station Capacity Needs

7.2.1 Kingsville TS

As the result of significant load growth in the Kingsville-Leamington area, peak load at Kingsville TS is expected to reach 73MW in the summer and 100MW in the winter within the next 5 years. The winter peak load would be well over the Kingsville TS LTR, if the 4x42 MVA station were to be downsized to a 2x42MVA station in 2018 as per the 2015 RIP plan.

In light of this new load forecast information, Hydro One and the LDC (Hydro One Distribution) have agreed that best alternative is to install larger units (2x83MVA) with relatively small incremental cost. The work is expected to be completed in 2019, and no further action is required to address Kingsville TS. The installation of 2x83MVA units would provide adequate transformation capacity as shown below.

Figure 3. Kingsville TS Winter Load Forecast & Winter LTR



7.2.2 Belle River TS, Lauzon TS (T5/T6 DESN)

Based on the summer forecast, Belle River TS and Lauzon TS (T5/T6 DESN) may exceed their station capacity within the study period. Table 3 below highlights the timing of the capacity need for each station.

Table 3. Station Capacity Needs Based on Summer Load Forecast

Station/DESN	Summer LTR (MW)*	Historical (MW)	Summer Load Forecast (Net) (MW)									
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Belle River TS	53.7	45.2	46.0	46.7	47.6	48.4	49.5	50.5	51.5	52.5	53.6	54.6
Lauzon TS T5/T6	100.8	95.5	105.1	103.6	102.7	102.0	101.5	101.0	100.8	100.4	100.0	99.6

Note *: at 0.9 power factor

However, there are capacitor banks installed at Belle River TS and Lauzon TS T5/T6, rated at 21.6MVar and 46.8 MVar, respectively. Further assessments determine that higher power factor resulting from the installed capacitor banks have effectively addressed the capacity needs identified above by increasing the LTR at Belle River TS and Lauzon TS to about 59MW and 112MW, respectively. As a result, the Study Team determines that no additional investments/plans are required.

7.2.1 Leamington TS

Based on the winter load forecast, Leamington TS may exceed its station supply capacity (LTR) by 2021, as shown in Table 4 below.

Table 4. Station Capacity Needs Based on Winter Load Forecast

Station/DESN	Winter LTR (MW)*	Historical (MW)	Winter Load Forecast (Net) (MW)									
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Leamington TS	194.8	0.0	0.0	73.9	139.3	161.8	204.9	204.5	204.6	204.3	204.2	204.0

Note *: at 0.9 power factor

Capacitor banks, rated at 43.2MVar, are planned to be installed at Leamington TS when it comes into service. Higher power factor resulting from the capacitor banks will imply that Leamington TS will have sufficient capacity over the study period (about 209MW), and no additional investments/plans are required. However, the station winter peak may occur at a time of high voltages in the region due to significantly lower demand in the broader Windsor-Essex region. In this case, the capacitor banks may not be deployed so as not to further aggravate the voltage situation. The Study Team recommends further evaluation of the Leamington TS capacity need through the Scoping Assessment.

7.3 Load Restoration Needs

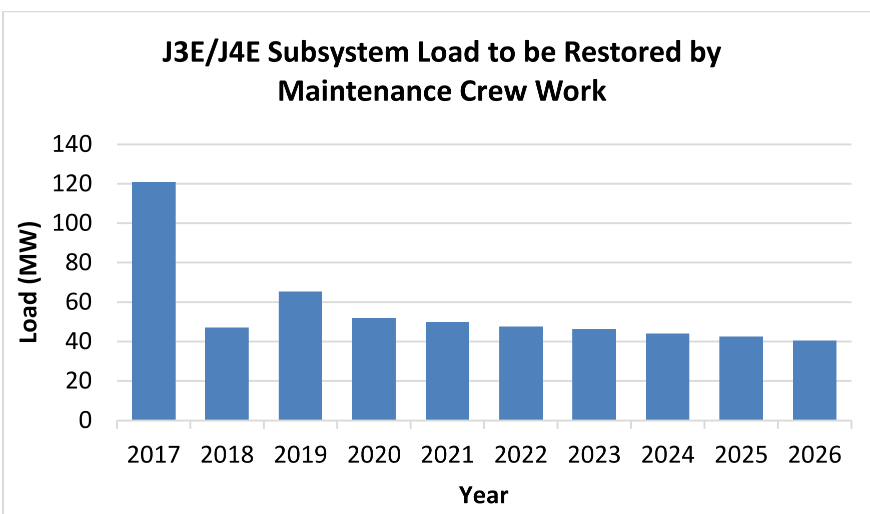
7.3.1 J3E/J4E Subsystem

Following the loss of 230kV double-circuit C23Z/C24Z, the entire load in the J3E/J4E subsystem would have to be met only through the path consisting of the Keith 230/115 kV autotransformers and J3E/J4E 115 kV circuits, by generation within the subsystem, and by load transfers out of the subsystem. Any balance of load would have to be restored through maintenance crew work or recall of an existing outage. This is expected to be accomplished within 8 hours.

Given the load forecast, generator effective capacity and contracts, load transfer limit, and ratings of circuits J3E/J4E and the Keith autotransformers, for the C23Z/C24Z contingency, Figure 4 shows the load that remains to be restored at summer peak through maintenance crew work or recall of existing outage. This load restoration is expected to be accomplished within 8 hours of the initial contingency. The large drop in load requiring maintenance crew work for restoration between 2017 and 2018 is due to the incorporation of Leamington TS and the transfer of load from Kingsville TS to the new station. From 2018 to the end of the study period, the level of load to be restored following the work of maintenance crew is of the order of about 40 MW. Restoration of this level of load within 8 hours meets the ORTAC restoration requirement. (It is assumed that the existing Keith autotransformers are replaced with 2x250MVA units in 2023, as per current sustainment plan.)

Considering the existing generation contracts expiring in the next 10-15 years, the amount of load that would require maintenance crew work for restoration could increase significantly and may exceed 150MW beyond the study period. The Study Team recommends that this need be further assessed in the next phases of the regional planning process, i.e. SA, IRRP and RIP.

Figure 4. J3E/J4E Subsystem Load to be Restored by Maintenance Crew Work



7.3.2 Other Restoration Needs

C21J/C22J, K2Z/K6Z and Z1E/Z7E contingencies will require some load to be restored within 4 hours as per ORTAC. In all cases (post-contingency) and with the new Leamington TS in-service in 2018, interrupted load can be restored by transfer below 150 MW within 4 hours. Remaining load below 150 MW can be restored within 8 hours through maintenance crew work. This would meet the ORTAC restoration requirement in the near- to mid-term. Whether further study of this issue is required, for the mid- to long-term, should be determined in the Scoping Assessment.

7.4 System Operational Issues

For the purposes of the Needs Assessment, the IESO identified issues related to overvoltage or thermal overload for select breaker failure and multiple element contingencies. The IESO will conduct a separate bulk planning study to determine if these events warrant changes to the Windsor Area Remedial Action Scheme to ensure the system can adequately handle these low probability events.

7.5 Aging Infrastructure

Hydro One has identified the following equipment to be reaching the end of their useful life in the next 10 years:

Table 5. Equipment Reaching End-of-Life in the Next 10 Years

Equipment	Replacement/ Refurbishment Timing
Crawford TS: T3 Transformer	2017
Malden TS: LV Breakers	2018
Kingsville TS: T1/T2/T3/T4 Transformers	2019
Keith TS: Autotransformers	2023
Lauzon TS: T1/T2 Autotransformers, T6 & T7 Step-Down Transformers	2025

Note that at this time, no other equipment in the region has been identified for major replacement/refurbishment. The scope of work, timing, and prioritization are under review/development and are subject to change.

The end-of-life equipment assessment for the above assets considered the following options:

1. Maintaining status quo
2. Downsizing equipment with lower ratings and built to current standards
3. Eliminating equipment
4. Replacing equipment with similar equipment with same ratings and built to current standards
5. Replacing equipment with similar equipment with higher ratings and built to current standards

With respect to (1), maintaining status quo for these assets is not an option due to the risk of equipment failure, customer outages and increased maintenance cost.

With respect to (2) and (3), downsizing or eliminating transformation capacity is not an option for the following reasons:

- Upgrading to higher capacity with similar type of equipment where there is forecast load growth or good utilization of current assets has little incremental cost. For example, it may cost $200-$300 thousand versus $5-$10 million in the future.
- Downsizing capacity today in areas where long-term load growth may be uncertain and then later upgrading due to eventual load growth would be significantly more costly (i.e. may result in incremental costs of $5-$10 million if additional capacity is needed within the lifetime of the new assets).
- In scenarios where facilities are well utilized or load is forecast to increase, maintaining or upgrading capacity to the maximum at the station is the most effective and efficient use of land and infrastructure for little incremental cost, if any. It also provides additional flexibility and reliable supply in emergency situations.

Therefore, for the assets currently identified in the region options (4) and (5) are considered preferred options.

7.5.1 Crawford TS

Crawford TS is in Essex County located North West of Windsor. It is supplied by 115 kV J3E and J4E circuits, that runs between Keith TS and Essex TS via Crawford junction. The station is comprised of two (2) step down transformers (T3/T4) in standard DESN configuration rated at 83 MVA with summer 10 day LTR of 91.2 MVA and supplies EnWin Utilities Ltd.

Hydro One has identified that T3 has reached the end of its useful life and in need of replacement in the near term. Considering Crawford TS is forecasted to be fully utilized throughout the study period, downsizing the station capacity is not a viable option given the capacity requirement of this station. The work involves replacement of T3 with the similar unit, 83MVA, removal of grounding transformers units GT3 and GT4, grounding the LV neutrals through Neutral Grounding Reactors, and upgrade of associated P&C system.

This near-term project is planned to be completed by the end of 2017.

7.5.2 Malden TS

Malden TS is located in North West of Windsor and supplied by the 230kV C21J and C22J circuits. The station is comprised of two (2) step down transformers (T1/T2) rated at 125 MVA with summer 10 day LTR of 203.8 MVA. Out of the twelve (12) feeders, six (6) supplies Hydro One Distribution and six (6) supplies EnWin Utilities Ltd. and embedded customer Essex Powerlines Corporation. These feeders supply power to downtown Windsor and the surrounding area.

The two (2) 27.6kV feeder breakers have reached end of life and Hydro One has planned to replace them with SF6 equivalents. Furthermore, AC station service system is also at end of its useful life which is also scheduled to be replaced with upgrade to associated P&C system.

The equipment replacements at Malden TS is planned to be completed by the end of 2018.

7.5.3 Kingsville TS

Kingsville TS is a major station in Essex County located south east of Windsor. It is supplied by double circuit 115kV line, K2Z and K6Z. The station is comprised of four non-standard transformers (T1/T2/T3/T4) rated at 42 MVA with the summer 10 day LTR of 158 MVA. The station supplies Hydro One Networks and embedded customers include several large farms, Local Distribution Companies (LDCs) such as E.L.K Energy Inc., Entegrus Powerlines Inc., Essex Powerlines Corporation and other large retail customers in Essex County.

T1, T2, and T4 transformers along with five LV breakers have reached the end of their useful life. Hydro One has planned to reconfigure the non-standard four-transformer DESN to standard two-transformer DESN. The end of life breakers will also be replaced with upgrade to associated P&C system and station service.

In the previous RIP, Hydro One had planned to downsize and reconfigure Kingsville TS from 4x42MVA to 2x42MVA, and reduce the Kingsville load to about 50 MW, and transfer the rest to Leamington TS.

As a result of the significant increase in load in the Kingsville area, Hydro One is proceeding with a plan to replace the 4x42 MVA transformers with 2x83 MVA units. In addition, it will help to manage the risk of failure of transformers T4 and T2. The state of these transformers is being monitored regularly. The replacement is planned to be in-service in November 2019, but may be sooner depending on the state of T4 and T2.

This project will be coordinated with the SECTR project, in that, some loads at Kingsville will be transferred to the new Leamington TS once the new station is placed in service in 2018.

7.5.4 Keith TS

Keith TS is located in the City of Windsor and is in service since 1952. It is comprised of two 230/115 kV 125 MVA autotransformers (T11/T12) connecting Chatham SS, Malden TS, Lauzon DS and Essex DS. Keith TS consists of one DESN (230/27.6 kV) with two power transformers (T22/T23) and another DESN (115/27.6 kV) with single power transformer (T1), supplying Hydro One Distribution, EnWin Utilities Ltd., and embedded customer Essex Powerlines Cooperation.

It was identified in the previous RIP that the autotransformers have neared the end of their useful life and in need of replacement. There is also operating flexibility limitations due to lack of self-cooled rating of the Keith autotransformers, as they would have to be taken out of service following the loss of station service. It was recommended in the previous RIP to replace with similar unit size (125 MVA), this however, has been revisited and the unit size will be upgraded to 250 MVA. The upgrade will provide long-term value at minimal cost increase, and will address the operating limitations as the new autotransformers will have self-cooled rating.

This project is currently planned to be completed in 2023.

7.5.5 Lauzon TS

Lauzon TS is a major station located in the North West of Windsor and comprised of two 230/115kV autotransformers (T1/T2) and two 230/27.6kV DESN (T5/T6 and T7/T8), rated at 83MVA with 10 day LTR of 112 MVA and 114.7 MVA respectively. This station supplies Hydro One Distribution and EnWin Utilities Ltd and embedded customers include E.L.K Energy Inc. and Essex Powerlines Corporation.

There are several station equipment that are at the end of its useful life including the autotransformers, T6/T7 step down transformers, HV breakers, etc. Considering load growth expected downstream in the 115kV subsystem, as well as the fact that Lauzon TS DESN is forecasted to be near capacity throughout the study period, Hydro One is currently planning to replace the autotransformers and the step transformers with similar size unit. Due to deteriorating condition, the station service transformer, SS2, one 115kV breaker, two LV breakers will be replaced with upgrade to associated ancillary equipment.

There may be opportunities to re-configure the station to improve system restoration following the loss of the circuits from Chatham to Lauzon and to consider if any upsizing would be merited based on future load and or changes to installed/contracted generation in the region. As such, it is recommended that this end-of-life need be considered further in the Scoping Assessment as it may benefit from more comprehensive planning through the IRRP process.

This work is tentatively planned to be complete in 2025.

7.6 Previously Identified Needs

The following needs were previously identified in the RIP, but no impacts/changes are recommended to the associated plan. These needs are listed below for reference only.

- SECTR Project
- 230kV/115kV circuit and 27.6kV feeder reconfiguration at Keith TS due to Gordie Howe International Bridge (GHIB) Project
- Additional feeder position at Malden TS
- Decommission of Tilbury TS and transfer of serviced load to a different supply point
- Decommission of T1 Transformer at Keith TS
- Replacement and upsizing of the Keith autotransformers to 250 MVA units

8 RECOMMENDATIONS

The Study Team recommendations are as follows:

a) Hydro One and relevant LDCs will develop an implementation plan for the following needs:
   - Replacement /refurbishment of EOL station equipment at Kingsville TS, Crawford TS, Malden TS, and Keith TS with similar type of equipment with same or higher ratings.
   - Station capacity needs at Kingsville TS, by replacing transformers with 2x83MVA units (as planned) to provide sufficient capacity over the study period.

b) Station capacity needs identified at Belle River TS and Lauzon TS (T5/T6 DESN) have been confirmed to be addressed by existing capacitor banks. No further investments are required.

c) Further assessment is required for the following needs via the coordinated regional planning process:
   - Station capacity need identified for Leamington TS if capacitor banks are not deployed.
   - Long-term restoration need for J3E/J4E subsystem for the loss of the circuits from Chatham to Lauzon.
   - Potential mid- to long-term load restoration needs for C21J/C22J, K2Z/K6Z, and Z1E/Z7E contingencies.
   - Sustainment needs at Lauzon TS which may lead to configuration changes/non-like-for-like replacement.

d) The IESO will undertake a bulk system study to further assess any changes that maybe needed to the Windsor Area Remedial Action Scheme to respect certain breaker failure or multiple element contingencies which may result in overvoltage or thermal overload.

The SA Study Team will decide if a regional or sub-regional approach is required for the needs recommended to be assessed and scoped in Scoping Assessment. The Scoping Assessment is expected to be completed by Q2 2018.

9 REFERENCES

[1] Planning Process Working Group (PPWG) Report to the Board: The Process for Regional Infrastructure Planning in Ontario. May 17, 2013

[2] IESO Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0

[3] Hydro One Networks Inc. Windsor-Essex Regional Infrastructure Plan. December 22, 2015

APPENDIX A: NON-COINCIDENT NET LOAD FORECAST (MW)

Summer

Station/DESN	LTR (MW)	Historical (MW)	Summer Net Forecast (MW)									
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Belle River TS	53.7	45.2	46.0	46.7	47.6	48.4	49.5	50.5	51.5	52.5	53.6	54.6
Chrysler WAP MTS	58.5	34.4	34.1	33.7	33.4	33.1	32.9	32.7	32.6	32.4	32.2	32.1
Crawford TS	91.5*	78.5	89.3	88.0	87.0	86.2	85.6	85.0	84.6	84.1	83.7	83.2
Essex TS	106.7	53.9	69.9	68.8	68.0	67.3	66.9	66.4	66.0	65.6	65.2	64.8
Ford Annex MTS	38.7	7.2	7.1	7.1	7.0	6.9	6.9	6.8	6.8	6.8	6.8	6.7
Ford Essex CTS	38.7	3.7	3.6	3.6	3.5	3.5	3.5	3.5	3.5	3.4	3.4	3.4
Ford Windsor MTS	58.5	10.9	10.9	10.7	10.6	10.5	10.5	10.4	10.4	10.3	10.3	10.2
G.M.Windsor MTS	38.7	0.0	13.0	12.9	12.7	12.6	12.6	12.5	12.5	12.4	12.4	12.3
Keith TS T1	37.5	8.6	8.5	8.4	8.3	8.2	8.2	8.2	8.1	8.1	8.0	8.0
Keith TS T22/T23	104.8	72.6	70.7	69.7	69.0	68.4	69.2	68.8	68.5	68.2	67.9	67.6
Kingsville TS	**	124.4	125.5	58.6	82.0	72.6	72.8	72.4	72.0	71.7	71.3	71.0
Lauzon TS T5/T6	100.8	95.5	105.1	103.6	102.7	102.0	101.5	101.0	100.8	100.4	100.0	99.6
Lauzon TS T7/T8	103.2	86.6	87.5	86.6	85.8	84.2	83.8	83.4	83.1	82.8	82.5	82.2
Leamington TS	183.4	0.0	0.0	78.1	132.7	116.4	119.4	119.5	119.9	120.1	120.4	120.6
Malden TS	183.4	114.1	122.0	121.9	120.9	121.1	120.7	120.3	121.0	121.6	122.2	121.9
Tilbury TS	7.2	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Tilbury West DS	30.6	19.1	18.9	18.8	18.6	19.3	19.2	19.2	19.2	19.2	19.3	19.3
Walker MTS #2	89.1	87.7	81.1	79.8	79.1	78.5	78.1	77.7	77.4	77.1	76.8	76.5
Walker TS #1	90.4	65.0	70.8	69.8	69.1	68.6	68.3	67.9	67.7	67.4	67.2	66.9

Winter

Station/DESN	LTR (MW)	Historical (MW)	Winter Net Forecast (MW)									
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kingsville TS	**	108.0	123.2	79.3	109.6	100.0	100.1	99.5	99.1	98.5	98.1	97.5
Leamington TS	194.8	0.0	0.0	73.9	139.3	161.8	204.9	204.5	204.6	204.3	204.2	204.0

Notes:
*: Crawford TS LTR after T3 replacement in 2017
**: Kingsville TS:
- LTR of existing configuration (4x42MVA): Summer: 145MW, Winter: 165MW
- LTR after replacement (2x83MVA): Summer: 104MW, Winter: 116MW

APPENDIX B: NON-COINCIDENT GROSS LOAD FORECAST (MW)

Summer

Station/DESN	LTR (MW)	Historical (MW)	Summer Gross Forecast (MW)									
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Belle River TS	53.7	45.2	46.6	47.9	49.3	50.6	52.0	53.3	54.7	56.0	57.4	58.8
Chrysler WAP MTS	58.5	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4	34.4
Crawford TS	91.5*	78.5	90.1	90.2	90.3	90.4	90.5	90.6	90.7	90.8	90.9	90.9
Essex TS	106.7	53.9	70.7	70.8	70.9	71.0	71.0	71.1	71.2	71.2	71.3	71.4
Ford Annex MTS	38.7	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2	7.2
Ford Essex CTS	38.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7	3.7
Ford Windsor MTS	58.5	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9	10.9
G.M.Windsor MTS	38.7	0.0	13.1	13.1	13.1	13.1	13.1	13.2	13.2	13.2	13.2	13.2
Keith TS T1	37.5	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6	8.6
Keith TS T22/T23	104.8	72.6	71.3	71.3	71.3	71.4	72.6	72.6	72.6	72.7	72.7	72.7
Kingsville TS	**	124.4	126.9	60.3	84.9	85.8	86.5	86.6	86.6	86.7	86.7	86.8
Lauzon TS T5/T6	100.8	95.5	106.5	106.7	106.8	107.0	107.1	107.3	107.4	107.6	107.7	107.9
Lauzon TS T7/T8	103.2	86.6	88.4	88.5	88.6	87.6	87.7	87.8	88.0	88.1	88.2	88.3
Leamington TS	183.4	0.0	0.0	79.5	136.5	143.8	147.8	148.8	149.8	150.9	151.9	152.9
Malden TS	183.4	114.1	123.3	124.6	124.9	126.2	126.5	126.8	128.1	129.4	130.6	131.0
Tilbury TS	7.2	0.9	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8
Tilbury West DS	30.6	19.1	19.2	19.3	19.4	20.2	20.3	20.4	20.5	20.6	20.7	20.8
Walker MTS #2	89.1	87.7	82.4	82.5	82.6	82.6	82.7	82.8	82.9	83.0	83.0	83.1
Walker TS #1	90.4	65.0	71.3	71.4	71.4	71.5	71.6	71.7	71.7	71.8	71.9	71.9

Winter

Station/DESN	LTR (MW)	Historical (MW)	Winter Gross Forecast (MW)									
		2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026
Kingsville TS	**	108.0	124.6	81.3	113.3	114.2	115.0	115.0	115.1	115.1	115.2	115.2
Leamington TS	194.8	0.0	0.0	75.2	143.3	191.0	237.1	238.1	239.1	240.1	241.2	242.2

Notes:
*: Crawford TS LTR after T3 replacement in 2017
**: Kingsville TS:
- LTR of existing configuration (4x42MVA): Summer: 145MW, Winter: 165MW
- LTR after replacement (2x83MVA): Summer: 104MW, Winter: 116MW

APPENDIX C: LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DCF	Discounted Cash Flow
DESN	Dual Element Spot Network
DG	Distributed Generation
DSC	Distribution System Code
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
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
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
ROW	Right-of-Way
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
TS	Transformer Station
TSC	Transmission System Code
UFLS	Under Frequency Load Shedding
ULTC	Under Load Tap Changer
UVLS	Under Voltage Load Rejection Scheme

APPENDIX E – 2018 WINDSOR-ESSEX SCOPING ASSESSMENT

WINDSOR-ESSEX REGION SCOPING ASSESSMENT OUTCOME REPORT

MARCH 2, 2018

ieso
Connecting Today. Powering Tomorrow.

Table of Contents

Scoping Assessment Outcome Report Summary			
Region:	Windsor-Essex		
Start Date	December 6, 2017	**End Date**	March 2, 2018

1. Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board’s ǻ“OEB” or “Board”ÆRegional Planning process. The scoping assessment process was led by the IESO in collaboration with the Regional Participants to determine the regional planning approach for the Windsor-Essex region for the needs identified by Hydro One Networks Inc. ǻ“Hydro One”Æ in the Needs Assessment Report[1] published in October 2017.

The first cycle of the regional planning process in the Windsor-Essex region was completed in 2015. Planning activities for the Windsor-Essex Region were already underway before the new regional planning process was introduced in 2013. The Needs Assessment (“NA”) and Scoping Assessment (“SA”) phases were deemed to be complete and the Windsor-Essex Region was identified as a “transitional” region. The Integrated Regional Resource Plan[2] (“IRRP”) was published in April 2015 followed by the publication of the Windsor-Essex Regional Infrastructure Plan[1] (“RIP”) in December 2015.

In accordance with the regional planning process, a regional planning cycle should be triggered every five years, or less if there are emerging needs. The NA completed in October 2017 was triggered by significant load growth and a new load forecast in the Kingsville-Leamington area. The final report concluded that some needs in the region may require regional coordination and more comprehensive planning, and should be reviewed further under the IESO-led scoping assessment process which is the second stage in the Board’s regional planning process.

The Independent Electricity System Operator ǻ“IESO”), in collaboration with the Regional Participants, further reviewed the needs identified along with information collected during the Needs Assessment, information on potential wires and non-wires alternatives, and the overall regional area impact to assess and determine the best planning approach for the whole or parts of the region. The available planning options considered in the Scoping Assessment include: an Integrated Regional Resource Plan, a Regional Infrastructure Plan (wires only plan), or a Local Plan.

---

[1] The Regional Infrastructure Plan from the previous planning cycle and the Needs Assessment report for the Windsor-Essex Region can be found at:
https://www.hydroone.com/about/corporate-information/regional-plans/windsor-essex

[2] The Integrated Regional Resource Plan for the Windsor-Essex Region can be found at:
http://www.ieso.ca/get-involved/regional-planning/southwest-ontario/windsor-essex

This Scoping Assessment report:

- defines the region (or sub-regions) for needs requiring more comprehensive planning as identified in the Needs Assessment report;
- determines the appropriate regional planning approach and scope for the region where a need for regional coordination or more comprehensive planning is identified;
- establishes a terms of reference when the IRRP is the recommended approach; and
- establishes the IRRP working group.

2. Team

The Scoping Assessment was carried out with the following Regional Participants:

- Independent Electricity System Operator
- Enwin Utilities Ltd.
- Essex Powerlines Corporation
- E.L.K Energy Inc.
- Entegrus Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)

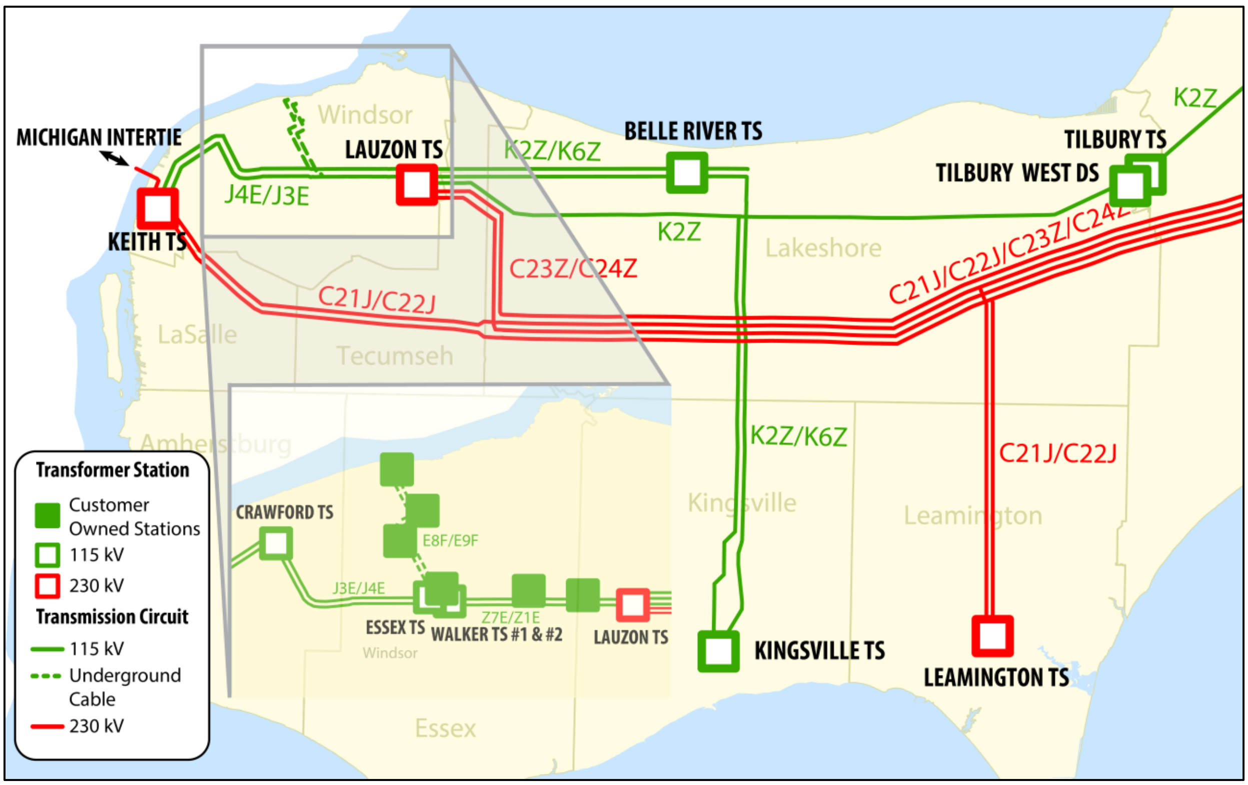
3. Categories of Needs, Analysis and Results

3.1 Overview of the Region

The Region is comprised of the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent and the Township of Pelee Island. The Windsor-Essex region also includes the Caldwell First Nation.

This Region, shown in Figure 1 below is comprised of and is served by five Local Distribution Companies ấ“LDCs”)0 ĒnWin Utilities Ltd. ấ“EnWin”ǼEssex Powerlines Corporation, E.L.K. Energy Inc., Entegrus Inc., and Hydro One. EnWin and Hydro One are directly connected to the transmission system, while the three other LDCs have low voltage connections to Hydro One distribution feeders.

Figure 1: Electricity Infrastructure in the Windsor-Essex Region



The Region is supplied from a combination of local generation and from connection to the Ontario grid via a network of 230 kV and 115 kV transmission lines and stations shown in Figure 2 below. Electricity distribution and conservation initiatives are carried out by the five LDCs serving the Region.

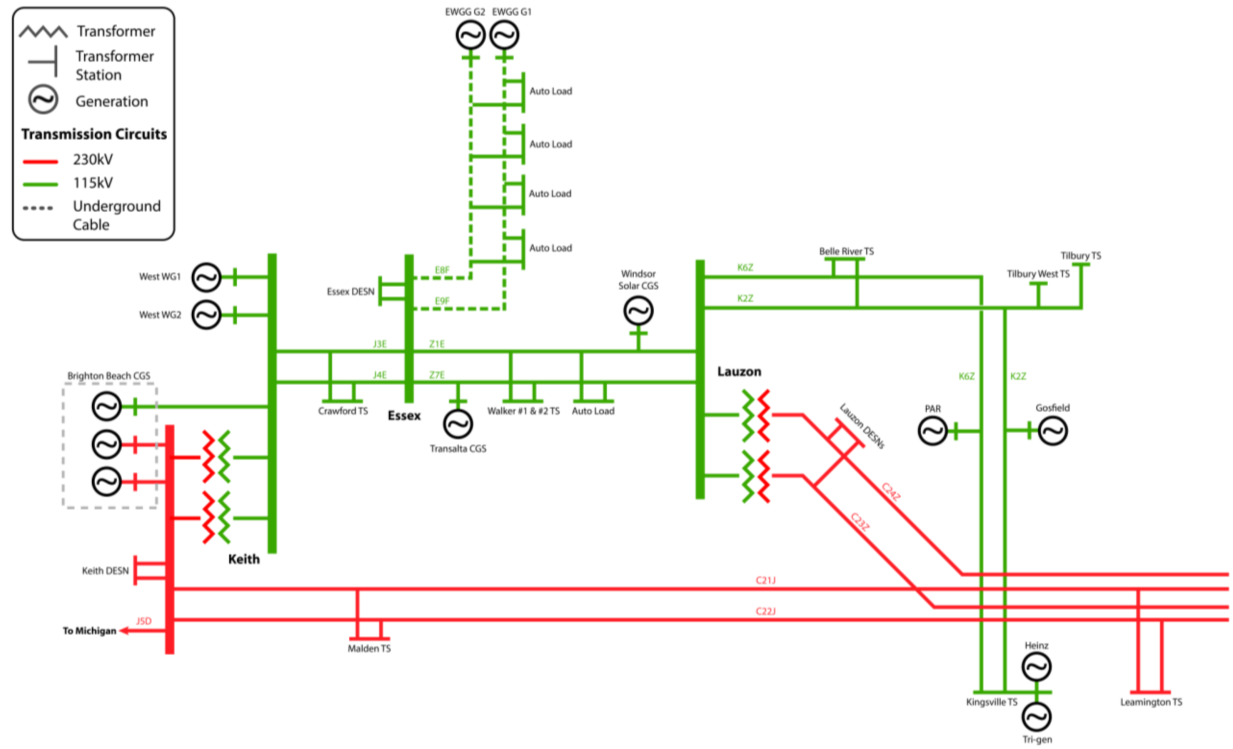


Figure 2: Single Line Diagram of Windsor-Essex Region

The urban portion of the Region in and around Windsor has a long history of advanced manufacturing, especially in the automotive sector. In light of this the transmitter and distributors have made historical investments in electricity infrastructure to enable a very high standard of reliability, which is of strategic importance to the regional and provincial economies. Entertainment tourism is particularly strong in the downtown core, the most significant individual component of which is a provincially owned resort casino.

The rural portion of the Region in Essex County supports a combination of manufacturing and agri-business. Essex County contains the largest concentration of greenhouse vegetable production in North America. This sector is expected to experience major growth in the future with much of the activity taking place in the Kingsville and Leamington areas, increasing electricity supply requirements. The County is also home to several large food processing operations, and a growing winery sector.

3.2 Background

This is the second cycle of regional planning for the Windsor-Essex Region. In the previous cycle, regional planning was underway in the Windsor-Essex Region prior to the OEB’s formalization of the regional planning process. The first phase of regional planning began with the regional plan developed by the former Ontario Power Authority ǻ“OPA”) as part of the 2007 Integrated Power System Plan ǻ“IPSP”)/ which identified a need for conservation as well as transmission reinforcement in the Region.

In 2010, a working group consisting of members from the former OPA, the transmitter, the five LDCs, and the IESO was formed. A study carried out by the former OPA and presented to the working group in 2011 recommended that development activities associated with the proposed Leamington TS temporarily be put on hold as a result of reduced regional electricity demand. In 2013, the former OPA revisited this study with an updated load forecast and the Supply to Essex County Transmission Reinforcement (“SECTR”) project was recommended to address near-term needs in the Kingsville-Leamington area.

In January 2014, Hydro One submitted a Leave to Construct application for this project with the OEB. As a continuation of this planning work for the Region the former-OPA completed the Windsor-Essex IRRP in April 2015. The RIP was published by Hydro One shortly after in December 2015. The RIP indicated that load at Kingsville TS was expected to be maintained under 50 MW and that load beyond this limit would be transferred to the new Leamington TS, expected to be in service by 2018. However, Hydro One Distribution indicated that they would engage in further assessment of the planned Kingsville TS reconfiguration if additional requests for connections were received.

The Needs Assessment was triggered in June 2017 due to significant forecast load growth in the Kingsville-Leamington area as a result of greenhouse sector expansion, above and beyond what had been forecast in the 2015 IRRP. Hydro One completed the Needs Assessment for the Windsor-Essex region on October 24th, 2017. Based on the forecast included in the Needs Assessment, the area supplied by Kingsville TS will become winter peaking by 2019. It is also forecast to exceed the capability of the downsizing plan originally proposed in the 2015 IRRP.

The needs identified in Hydro One’s Needs Assessment form the basis of the analysis for the Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

Hydro One’s Needs Assessment identified a number of needs in the Windsor-Essex region based on load forecasts, forecasted impacts of planned conservation and demand management ǻ“CDM”Ǽprograms/ expected distributed generation ǻ“DG”) capacity based on existing contracts, system reliability and operational issues in the region, along with major high voltage equipment identified to be at the end of their useful life and requiring replacement or refurbishment. The needs have been outlined below and include: station capacity needs, reliability/restoration needs, and end-of-life needs.

Station Capacity Needs

The Needs Assessment identified both potential near-term and mid- to long-term capacity needs throughout the planning period at the stations shown in Table 1.

Table 1: Station Capacity Needs

<table>
<tr><th>Station</th><th>Demand</th><th>Timing</th><th>Note</th></tr>
<tr><td>Kingsville TS</td><td>Winter</td><td>TBD</td><td>Peak load at Kingsville TS is forecast to reach 100 MW in the winter within the next 5 years. This would have exceeded the winter LTR if the station had been downsized to 2x42 MVA units as proposed in the 2015 plan. With Hydro One's current plant to install 2x83 MVA units there is no capacity need in the next 10 years based on transformer capacity, however upstream limitations need to be studied to confirm the station's load meeting capability.</td></tr>
<tr><td>Belle River TS</td><td>Summer</td><td>Long term [1]</td><td rowspan="2">Based on summer forecasts, Lauzon TS T5/T6 is expected to exceed station capacity from 2017 to 2023 and Belle River TS is expected to exceed its capacity in 2026. The timing and magnitude of these needs depends heavily on power factor assumptions and the conservation forecast.</td></tr>
<tr><td>Lauzon TS</td><td>Summer</td><td>Near term [1]</td></tr>
<tr><td>Leamington TS</td><td>Winter</td><td>Near term</td><td>Leamington TS is forecast to exceed its winter LTR by 2021. The IESO has had further conversations with Hydro One Distribution since the completion of the Needs Assessment which indicate the potential load growth may exceed what was known at the time; potentially advancing the need date to as early as 2020 (approximately 80 MW of additional forecast load growth since the Needs Assessment was completed).</td></tr>
</table>

[1] Hydro One's Needs Assessment determined that when accounting for improved power factor assumptions, due to the capacitor banks installed at these stations, the need could be deferred beyond 10-year study period.

Reliability/Restoration/Security Needs

The Needs Assessment identified potential restoration needs for the loss of C23Z/C24Z or C21J/C22J or K2Z/K6Z or Z1E/Z7E. Due to expiring generation contracts in the next 10-15 years, load requiring restoration could increase, impacting the timing and magnitude of these restoration needs.

Bulk System Needs

In the Needs Assessment, the IESO identified issues related to overvoltage or thermal overload for select breaker failure and multiple element contingencies. These issues are dependent on bulk system conditions such as high import/exports.

End-of-Life Needs

Hydro One identified the equipment shown in Table 2 to be reaching end-of-life within the study period.

Table 2: Equipment Reaching End-of-life in the Next 10 Years

Equipment	Need Date
Crawford TS: T3 Transformer	2017 - Completed
Malden TS: Low Voltage Breakers	2018
Kingsville TS: T1/T2/T3/T4 Transformers	2019
Tilbury TS	2020
Keith TS: Autotransformers	2023
Lauzon TS: T1/T2 Autotransformers, T6 & T7 Step-Down Transformers	2025

Plans are already underway for the majority of these investments, as outlined in the following section. These plans reflect the outcomes of the last cycle of regional planning process or planning that occurred between Hydro One and the applicable LDCs.

Projects and Plans Underway

The RIP published in December 2015 identified the wires work required to meet existing system needs. The Needs Assessment also identified plans developed by Hydro One and the LDCs in the subsequent period between the RIP and Needs Assessment publication. These projects, outlined in Table 3, provide a basis for future assessments of the region and should be accounted for in planning.

Table 3: Projects Currently Underway

Need	Plan	I/S Date
Kingsville TS End-of-Life / Capacity Need	Hydro One and Hydro One Distribution have agreed to install larger units (2x83 MVA).	2019
Crawford TS End-of-Life	Replacement of T3 with the similar unit (83 MVA), removal of grounding transformers units GT3 and GT4, grounding the LV neutrals through Neutral Grounding Reactors and upgrade of associated protection and control systems.	2017 - Completed
Keith TS End-of-Life	Replace end-of-life 230 kV/115 kV autotransformers, upgrading from 125 MVA to 250 MVA units.	2023
	Decommission the end-of-life T1 (115 kV/27.6 kV) transformer.	TBD

Need	Plan	I/S Date
Relocation for Gordie Howe International Bridge Project	Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to allow for the construction of the Gordie Howe Bridge	2018
Tilbury TS End-of-Life	Decommission of Tilbury TS and transfer of serviced load to a different supply point.	2020
Kingsville-Leamington Capacity Need / 115kV System Restoration Need	SECTR project as outlined in the RIP. Project includes Leamington TS, 13 km 2-circuit 230 kV line and distribution work for Leamington TS.	2018

3.4 Analysis of Needs and Planning Approach

An Integrated Regional Resource Plan is recommended for the Windsor-Essex Region due to:

- the potential for non-wires solutions to address the identified capacity and restoration needs,
- the opportunities to maximize use of end-of-life assets,
- the potential reliability impact of large local generation reaching contract expiry in the mid-term and not being re-contracted due to the IESO's Market Renewal project, and
- the need to ensure that future planning is consistent with the decisions made in the first cycle of regional planning.

In addition to the needs requiring regional planning, there are some needs which will be addressed either by the IESO through its bulk planning process or through local planning between the transmitter and the impacted LDC(s).

Windsor-Essex Integrated Regional Resource Plan

The IRRP for Windsor Essex Region will focus on ensuring the region continues to have sufficient supply capability, meeting reliability standards, and analyzing assets reaching end-of-life to take advantage of opportunities they may present.

The IRRP will confirm transformer station capacity needs and carry out an assessment of options for confirmed needs, including additional conservation or other non-wires alternatives. The capacity need in the Kingsville and Leamington areas is predicted to continue to grow quickly as more greenhouse operations materialize. The working group recognizes that due to the urgency of the need, as well as the lead time required for potential wires solutions, a hand-off letter to Hydro One may be required early on in the regional planning process to recommend that Hydro One Transmission proceed with work to provide additional transformation supply to the Leamington area.

The potential for non-wires solutions, such as demand response and distributed energy resources, will still be explored in parallel in order to identify options now to manage continued growth in the Kingsville and Leamington areas over the long term. The IRRP will also identify if any additional 230kV/115kV reinforcements are necessary to accommodate load growth in the area.

The IRRP will further assess the impact of existing conservation programs at Lauzon TS and Belle River TS and confirm the impact on the identified capacity need and timing.

The IRRP will evaluate the impact of the updated demand forecast on restoration needs and collect information on reliability issues and load transfer capabilities. These needs may affect multiple LDCs, and all LDCs may play a role in meeting them. The IRRP will also study the potential impacts of generation in the region going off contract due to the ongoing Market Renewal processes. Non-wires options such as demand response and distributed generation will be considered alongside transmission reinforcement or enhanced load transfer capability.

Facilities reaching end-of-life provide an opportunity to re-examine their current use and configuration in the context of the latest load forecast and generation data to ensure that any new assets installed in their place will continue to appropriately service both the impacted LDCs/ and their customers/ over the new assets' lifetime.

Plans to replace end-of-life facilities at Crawford TS, Kingsville TS, and Keith TS, identified previously in the RIP, are continuing. However, any scope changes/new information should continue to be shared as it becomes available. The IRRP will confirm the new load meeting capabilities of Kingsville TS using the updated demand forecast and Hydro One's latest refurbishment plan, and assess upstream limitations, particularly under winter conditions.

Options to re-configure or up-size end-of-life facilities at Lauzon TS will also be studied in the IRRP due to the potential to address system restoration or supply capacity needs.

The IRRP will also examine the current supply to Tilbury West HVDS to determine if additional reinforcements are required to adequately supply Entegrus load once the decommissioning of Tilbury TS is complete.

Bulk System Planning

In the Needs Assessment, the IESO identified issues related to overvoltage or thermal overload for select breaker failure and multiple element contingencies; these issues are linked to bulk system conditions such as high import/exports. The IESO will conduct a bulk study which may involve updating the Windsor Area remedial action scheme ǻ"RAS"ǼResults of the study will form an input to the IRRP, particularly in options development.

Local Planning

The end-of-life need at Malden TS to replace low voltage breakers does not require further regional planning. A local planning process is recommended to address this need, as it requires a limited investment in a wires solution and does not require further regional stakeholder engagement.

4. Conclusion

The Scoping Assessment concludes that:

- Based on the needs identified in the Needs Assessment, an IRRP is recommended for the Windsor-Essex region. The IRRP scope will include the following:
    - capacity needs in the Kingsville and Leamington areas,
    - confirmation of the load meeting capabilities of Kingsville TS after reconfiguration,
    - capacity needs at Lauzon and Belle River TS,
    - system restoration needs following loss of the C23Z/C24Z or C21J/C22J or K2Z/K6Z or Z1E/Z7E double circuit lines, and
    - Lauzon TS re-configuration or upsizing.
- The work to implement recommendations from the previous IRRP and RIP should continue.
- The IESO will conduct a separate bulk planning process in parallel with IRRP. The results will be incorporated into the regional planning processes as they become available.
- A Local Planning process is recommended for end-of-life needs at Malden TS.

The draft Terms of Reference for the Windsor-Essex IRRP is attached in Appendix A.

List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
IESO	Independent Electricity System Operator
IPSP	Integrated Power System Plan
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
MW	Megawatt
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
RAS	Remedial Action Scheme
RIP	Regional Infrastructure Plan
RPP	Regional Planning Process
SA	Scoping Assessment
SECTR	Supply to Essex County Transmission Reinforcement
TS	Transformer Station

Appendix A0Draft Terms of Reference 1

The Windsor-Essex IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan ǻ“IRRP”Ǽfor the Windsor-Essex region.

Based on the near- and mid-term capacity needs identified within the region, continued forecast growth in the greenhouse sector, local gas generation contracts expiring in the mid- to long-term, and opportunities for coordinating demand and supply options with end-of-life needs, an integrated regional resource planning approach is recommended.

The Windsor-Essex Region

The Windsor-Essex region is a summer-peaking region that includes the City of Windsor, Town of Amherstberg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, and the western portion of the Municipality of Chatham-Kent. The region is supplied from the Keith, Crawford, Essex, Walker #1, Walker #2, Malden, Lauzon, Kingsville, Belle River, Tilbury, Tilbury West, and Leamington transformer stations (TS). The Windsor-Essex region also includes Caldwell First Nation. The approximate geographical boundaries of the sub-region are shown in Figure A-1.

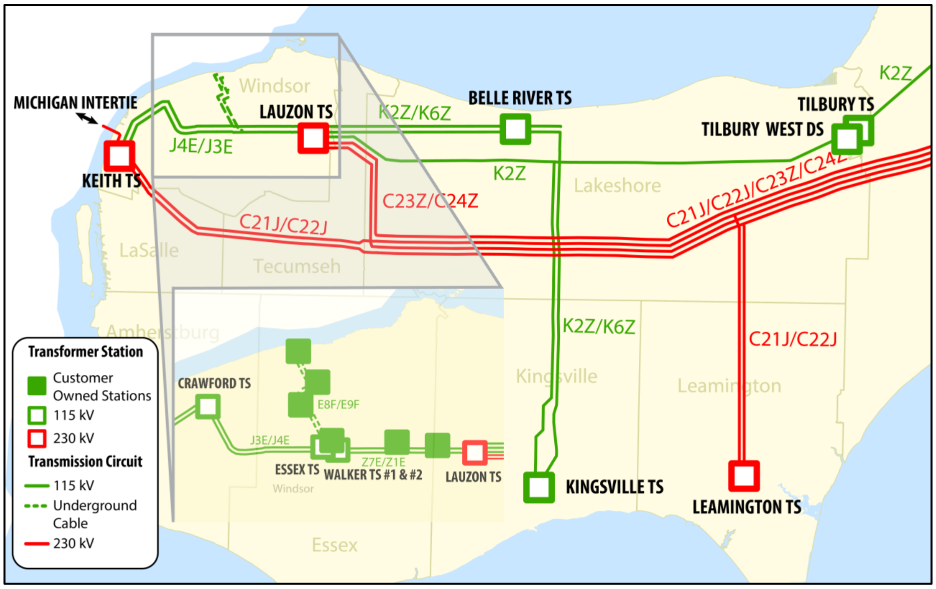


Figure A-1: Electricity Infrastructure in the Windsor-Essex Region[3]

Windsor-Essex Region Electricity System

The electricity system supplying the Windsor-Essex region is shown in Figure A-2.

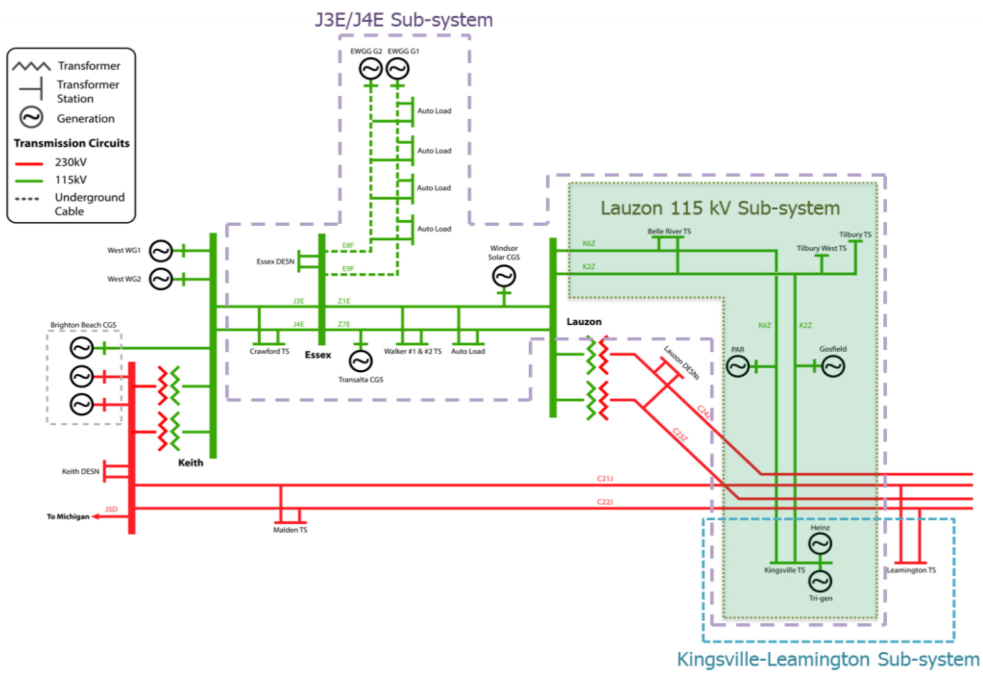


Figure A-2: Single Line Diagram of Electricity System Supplying the Windsor-Essex Region

[3] The region is defined by electricity infrastructure; geographical boundaries are approximate.

For study purposes, three electrical sub-systems have been identified within the Windsor-Essex region:

1. The J3E/J4E sub-system: Includes the load that would be supplied via circuits J3E and J4E for the loss of C23Z and C24Z, along with the Lauzon TS DESN loads on C23Z and C24Z which can be resupplied from the 230 kV/115 kV autotransformers post-contingency.
2. The Lauzon 115 kV sub-system: Includes the transformer stations and generators connected to circuits K2Z and K6Z.
3. The Kingsville-Leamington sub-system: Includes the load supplied by, and generation connected to, Kingsville TS or the new Leamington TS.

Background

In May 2013 the OEB endorsed the Planning Process Working Group's report, formalizing the regional planning process. At that time, regional planning was already underway in the Windsor-Essex region. As such, the Windsor-Essex region was on one of the first regions to undergo the new regional planning process. However, due to how far planning for the region had progressed before the OEB formalized process was implemented, no formal Needs Assessment or Scoping Assessment was published in the first cycle of planning for the region.

In April 2015, the IESO published an IRRP for the Windsor-Essex region which was focused on supply to the Kingsville/Leamington sub-system and restoration of the J3E/J4E sub-system. The main recommendation of this plan was the development of a new 230 kV DESN station, Leamington TS. Subsequently, and in accordance with the OEB's process, Hydro One Transmission published the Windsor-Essex Regional Infrastructure Plan ("RIP"). In addition to reconfirming the details of Leamington TS, the RIP also recommended plans to address a number of end-of-life needs, including the replacement of the Keith autotransformers.

Since the RIP was published, the needs in the Windsor-Essex region have continued to evolve. While the 2015 IRRP had indicated that of the four end-of-life transformers at Kingsville TS only two should be replaced with 2x42 MVA units. This would have resulted in the limited time rating ("LTR") of the station decreasing from about 120 MW to approximately 60 MW. In light of the continued load growth in the area driven by expansion of greenhouse growing operations, Hydro One Distribution and Hydro One Transmission are proceeding with a plan to install 2x83 MVA units, providing a summer LTR of approximately 100 MW.

Additionally, while the RIP had indicated that the autotransformers at Keith TS should be replaced like-for-like, further discussions with Hydro One and studies completed by the IESO, which considered potential impacts to local generation in the area over the course of the equipment's life-time, have confirmed that the incremental cost to upgrade the units at end-of-life to 250 MVA units would be justified.

In the summer of 2017, Hydro One made the IESO aware that the forecast load growth and development interest from greenhouse growers in the Leamington area was exceeding the levels identified in the 2015 IRRP and RIP. In response to the evolving near- to mid- term capacity needs in the region, the IESO and Hydro One decided to begin the next cycle of regional planning early.

Hydro One completed the Needs Assessment for the Windsor-Essex region in October 2017, identifying capacity needs, predominately at Leamington TS, and a number of sustainment and load restoration needs; some of which require boarder regional consideration. Since the Needs Assessment was published, Hydro One Distribution has continued to update their load forecast, indicating that the need date for additional capacity at Leamington TS continues to advance.

2. Objectives

1. To assess the adequacy of electricity supply to customers in the Windsor-Essex region over the next 20 years.
2. To provide certainty around meeting pent-up electrical demand from greenhouse growers in the region by confirming scope and timing of required near-term infrastructure investments.
3. To integrate asset renewal needs with the sub-region's mid- to long-term capacity and reliability needs, and develop a flexible, comprehensive electricity plan for the Windsor-Essex region.
4. To develop an implementation plan that maintains flexibility in order 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.

3. Scope

This IRRP will develop and recommend an integrated plan to meet the needs of the Windsor-Essex region. The plan is a joint initiative involving Hydro One Distribution, Essex Powerlines Corporation, Ewin Utilities Ltd., E.L.K. Energy Inc., Entegrus Inc., Hydro One Transmission, and the IESO, and will also incorporate input from community engagement activities. The plan will focus on the addressing near-term capacity needs in the Kingsville/Leamington sub-system, and assessing any existing or emerging restoration or supply security needs. Opportunities for end-of-life investments to aid in meeting these needs will also be explored. Like all IRRPs, in its identification or confirmation of any capacity or restoration needs, and analysis of options for addressing end-of-life needs, the plan will integrate forecast electricity demand growth, conservation and demand management ("CDM") in the area with transmission and distribution system capability, relevant community plans, other bulk system developments, and distributed energy resources ("DER") uptake.

The scope of the Windsor-Essex IRRP includes the following infrastructure:

- 230 kV Connected Stations – Malden TS, Keith TS, Lauzon TS, Leamington TS
- 115 kV Connected Stations – Crawford TS, Essex TS, Walker TS #1, Walker TS #2, Belle River TS, Tilbury West HVDS, Tilbury TS, Kingsville TS
- Five customer owned transformer stations on the 115 kV system
- 230 kV Transmission Lines – C21J/C22J, C23Z/C24Z, J5D
- 115 kV Transmission Lines – J3E/J4E, Z1E/Z7E, K2Z/K6Z
- 115 kV Transmission Cables – E8F/E9F
- 230/115 kV auto-transformers at Keith TS and Lauzon TS
- Existing local generation assets

The adequacy of the bulk system supplying the area is being assessed by the IESO in parallel with this study through a separate bulk system planning process. Results of that study will be shared with the Working Group and incorporated into applicable regional studies as they become available.

Based on the identified needs, the Windsor-Essex IRRP process will consist of the following activities:

1) Creation of an updated 20-year demand forecast for the region.
2) Confirming the adequacy of transformer station ratings and the area's load meeting capability and reliability.
    a. Identify or confirm the transformer station capacity needs and sufficiency of the area's load meeting capability for the study period using the updated load forecast.
    b. Confirm identified restoration needs using the updated load forecast.
    c. Collect information on any know reliability issues and load transfer capabilities from the Local Distribution Companies ("LDCs").
3) For confirmed needs, carry out an assessment of options. Options are evaluated using decision making criteria included, but not limited to, technical feasibility, economics, reliability performance, environmental and social factors. Evaluation criteria will be informed through community engagement activities and reflect attributes deemed important to the community-at-large.

The options analysis has been divided into groupings based on the priority/timing of the needs, any known lead time information, and the depth of analysis required.

a. Phase 1:
    i. Identify options for meeting the near-term capacity need identified for the Leamington area and, based on the working group's recommendation, issue a hand-off letter to Hydro One.
    ii. Confirm the load meeting capability of Kingsville TS for a winter peak.
    iii. Determine the level of load restoration need that exists for the loss of C23Z/C24Z or C21J/C22J or K2Z/K6Z or Z1E/Z7E, as impacted by the additional capacity needs and proposed solutions for the Kingsville/Leamington sub-system.
b. Phase 2:
    i. Identify options for the end-of-life step-down transformers and autotransformers at Lauzon TS.
    ii. Identify the options for remaining transformer station capacity needs (e.g., Lauzon TS, Belle River TS), accounting for opportunities to manage load growth or upsize or re-configure facilities at end-of-life.
    iii. Determine whether additional reinforcements to the supply to Tilbury West HVDS are required due to the decommissioning of Tilbury TS, in order to respect relevant planning criteria.
    iv. Assess whether additional 230 kV or 115 kV system reinforcements are needed in the mid- to long-term to accommodate load growth in the Kingsville/Leamington area, or to account for expiring generation contracts, and develop a set of options as appropriate in order to respect relevant planning criteria. Outcomes of the IESO's bulk planning study should also be incorporated.

4) Development of the long-term recommendations and the implementation plan.
5) Completion of the IRRP report documenting the near-, mid-, and long-term needs and recommendations.

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in section 4 below.

4. Data and Assumptions

The plan will consider the following data and assumptions:

- Demand Data

  - Historical coincident & non-coincident peak demand information for the sub-region
  - Historical weather correction, for median and extreme conditions
  - Gross peak demand forecast scenarios by region, TS, winter/summer, etc.
  - Coincident peak demand data including transmission-connected customers
  - Identified potential future load customers

- Conservation and Demand Management
  - LDC CDM plans
  - Incorporation of verified LDC results and progression towards OEB targets, and any other CDM programs/opportunities in the area
  - Long-term conservation forecast for LDC customers, based on sub-region's share of the 2013 Long-Term Energy Plan target
  - Conservation potential studies, if available
  - Potential for CDM at transmission-connected customers' facilities
  - Load segmentation data for each TS based on customer type (e.g., residential, commercial, industrial, agricultural) and proportion of LDC service territory within the study area

- Local 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, as applicable
  - LDC Distribution System Plans
  - Community Energy Plans and Municipal Energy Plans (e.g., Windsor Community Energy Plan)
  - Municipal Growth Plans
  - Any transit plans impacting electricity use or tied to community developments

- 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
  - System capability as per current IESO PSS/E base cases
  - Transformer station ratings (10-day LTR) as per asset owner
  - Load transfer capability
  - Technical and operating characteristics of local generation

- End-of-life asset considerations and sustainment plans
  - Transmission assets
  - Distribution assets
  - Impact of on-going plans and projects on applicable facility ratings

- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Transmission
- Enwin Utilities Ltd.
- Essex Powerlines Corporation
- E.L.K Energy Inc.
- Entegrus Inc.
- Hydro One Distribution

Authority and Funding

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

5. Engagement

Integrating early and sustained engagement with communities and stakeholders in the planning process was recommended by the IESO 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, and the focus on community and stakeholder engagement continues to be a priority in the 2017 Long-Term Energy Plan. As such, the Working Group is committed to conducting plan-level engagement throughout the development of the Windsor-Essex IRRP.

The first step in engagement will consist of meetings with municipalities and Indigenous communities within the planning area, Indigenous communities who may have an interest in the planning area, and the Métis Nation of Ontario to discuss regional planning, the development of the Windsor-Essex plan, and integrated solutions.

Municipal engagement will continue throughout the development and completion of the plan. Since agriculture is a significant source of forecast load growth for the region, engagement activities will also focus on obtaining input and feedback from greenhouse growers in the Kingsville and Leamington areas.

The Working Group will develop a comprehensive stakeholder engagement plan, according to the Activities Timeline shown in Section 6.

6. Activities, Timeline and Primary Accountability

Table A-1 Summary of IRRP Timelines and Activities

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	Jan 2018
2	**Develop the Planning Forecast for the sub-region**			
	Establish historical coincident and non-coincident peak demand information	*IESO*	- Long-term planning forecast scenarios	Feb – Apr 2018
	Establish historical weather correction, median and extreme conditions	*IESO*		
	Establish gross peak demand forecast and high/low growth scenarios	*LDCs*		
	Establish existing, committed and potential DG	*LDCs*		
	Establish near- and long-term conservation forecasts based on LDC CDM plans and LTEP CDM targets	*IESO*		

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
	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**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Apr 2018
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Q2 2018
5	**Early Wires Planning**			
	Identify potential wires options to address local near-term capacity needs in the Leamington area	*Hydro One Transmission*	- Cost, feasibility and reliability performance of potential wires options - Detailed option development	Q1-Q2 2018
	Provide information on cost, feasibility and reliability performance of identified wires options for the purpose of developing integrated solutions			
6	**Hand off Wires Component of Integrated Solution**			
	Leamington TS Capacity Needs	*IESO*	- Hand-off letter to Hydro One	May 2018
7	**Complete system studies to identify needs over a 20-year period** - Obtain PSS/E base case, include bulk 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	Q2-Q3 2018
8	**Develop Options and Alternatives**			
	Develop conservation options	*IESO and LDCs*	- Develop flexible planning options for forecast scenarios	Q2-Q3 2018
	Develop local generation options	*IESO and LDCs*		

	Activity	Lead Responsibility	Deliverable(s)	Timeframe
	Develop transmission (see Action 7 below) and distribution options	*Hydro One, and LDCs*	- Deliverables staged according to the three phases outlined in section 3	
	Develop options involving other electricity initiatives (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Integrate with bulk needs	*IESO/HONI*		
	Develop portfolios of integrated alternatives	*All*		
	Technical comparison and evaluation	*All*		
9	**Plan and Undertake Community & Stakeholder Engagement**			
	Early engagement with local municipalities and Indigenous communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*	- Community and Stakeholder Engagement Plan - Input from local communities - Input from greenhouse growers	Q2 2018
	Develop communications materials	*All*		Q3-Q4 2018
	Undertake community and stakeholder engagement	*All*		
	Summarize input and incorporate feedback	*All*		
10	**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	Q4 2018
11	**Prepare the IRRP report detailing the recommended near, medium and long-term plan for approval by all parties**	*IESO*	- IRRP report	Q1 2019

APPENDIX F – 2019 WINDSOR-ESSEX IRRP

Integrated Regional Resource Plan

Windsor-Essex

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

The IESO prepared the IRRP on behalf of the Windsor-Essex Regional Planning Technical Working Group (Working Group), which includes the following members:

- Independent Electricity System Operator
- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- ENWIN Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution) (Transmission)

The Working Group assessed the adequacy of electricity supply to customers in the Windsor-Essex region over a 20-year period; developed a flexible, comprehensive, integrated plan that considers opportunities for coordination in anticipation of potential demand growth and varying supply conditions in the Windsor-Essex region; and developed an implementation plan for the recommended options, while maintaining flexibility to accommodate changes in key conditions over time.

The Working Group members agree with the IRRP's recommendations and support implementation of the plan through the recommended actions, subject to obtaining all necessary regulatory and other approvals.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Acronyms

Acronym/ Alternative	Descriptions
A	Amp or Ampere
ACSR	Aluminum conductor steel-reinforced
ASABE	American Society of Agricultural and Biological Engineers
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CHP	Combined Heat and Power
DESN	Dual Element Spot Network
DG	Distributed Generation
DER	Distributed Energy Resource
DLC	DesignLights Consortium
DR	Demand Response
DS	Distribution Station
EA	Environmental Assessment
E.L.K.	E.L.K. Energy Inc.
Entegrus	Entegrus Powerlines Inc.
ENWIN	Enwin Utilities Ltd.
EPL	Essex Powerlines Corporation
FIT	Feed-in Tariff
GIF	Grid Innovation Fund
HPS	High Pressure Sodium
HV	High Voltage
Hydro One	Hydro One Networks Inc.
IESO	Independent Electricity System Operator

Acronym/ Alternative	Descriptions
IRRP	Integrated Regional Resource Plan
JCT	Junction
kV	Kilovolt
LAC	Local Advisory Committee
LDC	Local Distribution Company
LED	Light Emitting Diode
LEI	London Economics International
LMC	Load Meeting Capability
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MVA	Mega Volt Ampere
MW	Megawatt
NWA	Non-Wires Alternative
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SECTR	Supply to Essex County Transmission Reinforcement
SIA	System Impact Assessment
SPS	Special Protection System
SS	Switching Station
STE	Short-Term Emergency
TS	Transmission Station or Transformer Station
TWh	Terawatt-Hour
ULTC	Under-load Tap Changer
Working Group	Technical Working Group for Windsor-Essex Region IRRP

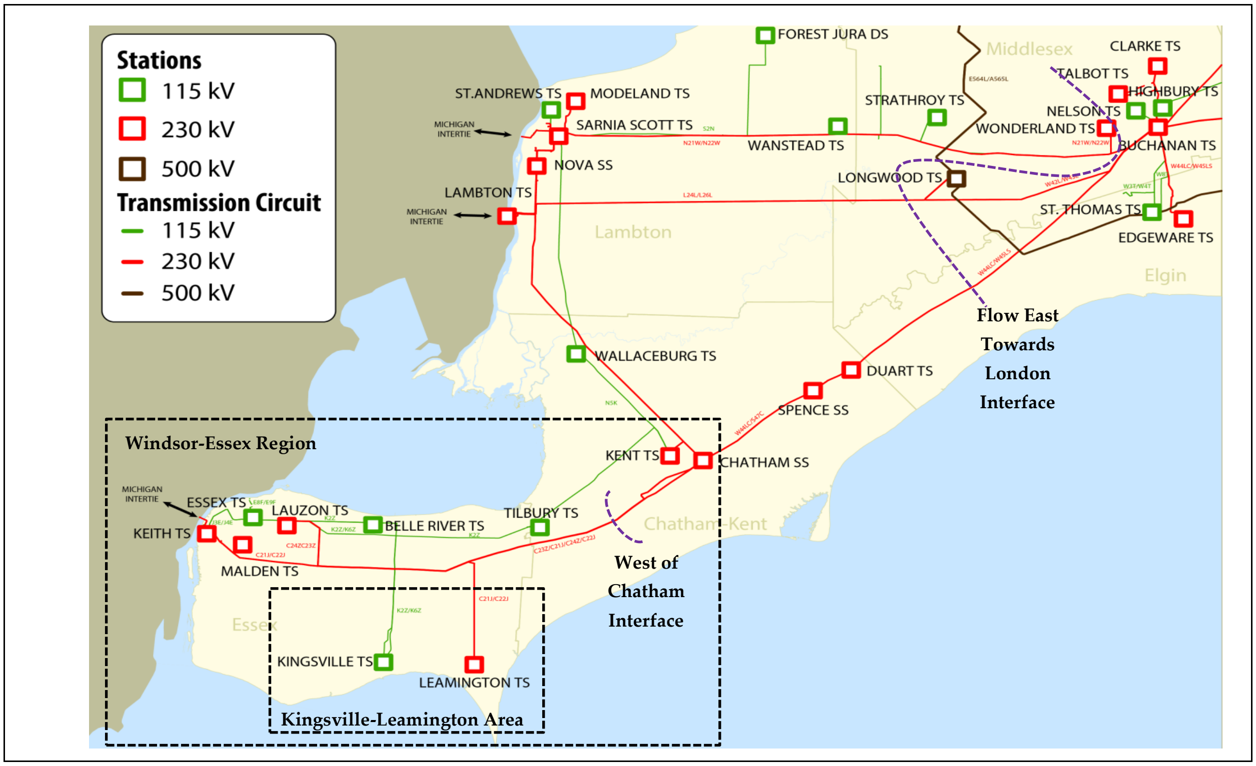
1. Introduction

This Integrated Regional Resource Plan (IRRP) considers and develops a plan to address the electricity needs of the Windsor-Essex region over the next 20 years. This report was prepared by the Independent Electricity System Operator (IESO) on behalf of the Working Group composed of the IESO, E.L.K. Energy Inc. (E.L.K.), Entegrus Powerlines Inc. (Entegrus), Enwin Utilities Ltd. (ENWIN), Essex Powerlines Corporation (EPL), and Hydro One Networks Inc. (Hydro One). These five local distribution companies (LDCs) serve customers in the Windsor-Essex region; ENWIN and Hydro One are directly connected to the transmission system, while Entegrus, E.L.K., and EPL have low-voltage connections to Hydro One distribution feeders.

In Ontario, planning to meet the electrical supply and reliability needs of a large area or region is conducted through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for each of the province's 21 electricity planning regions, including the Windsor-Essex region, at least once every five years. The Windsor-Essex region includes the City of Windsor, Town of Amherstburg, Town of Essex, Town of Kingsville, Town of Lakeshore, Town of LaSalle, Municipality of Leamington, Town of Tecumseh, the western portion of the Municipality of Chatham-Kent, and the Township of Pelee Island. The Windsor-Essex region also includes Caldwell First Nation. It is one of seven planning regions in Southwest Ontario, adjacent to the Chatham-Kent/Lambton/Sarnia region to the east.

The Windsor-Essex region population of approximately 400,000 people remained relatively flat over the last 10 years. Economic diversification is driving the region's electricity growth and use, specifically agriculture, manufacturing, and entertainment tourism in the city core. While growth in the automotive sector in Windsor-Essex has tempered during this period, Windsor is still the country's manufacturing and automotive powerhouse. Other emerging industries, particularly agriculture, have led to substantial growth in the area. The Kingsville-Leamington area within the Windsor-Essex region is home to North America's largest concentration of greenhouse vegetable production. This rapid expansion, development in cannabis growth operations, and the shift to year-round artificial crop lighting, will continue to increase electricity supply requirements in the Kingsville-Leamington area, which are expected to double over the next five years.

Figure 1-1: The Windsor-Essex Region (Study Area)



This IRRP identifies power system capacity, reliability requirements, and end-of-life asset replacement needs and coordinates options to meet customer needs in the area over a 20-year period. Given forecast uncertainty, the longer development lead time and the potential for technological change, the plan does not recommend specific investments or projects to meet mid- and long-term needs, but maintains the flexibility to evolve in step with emerging developments. Instead, this IRRP focuses both on recommendations to meet near-term needs, and on the near-term actions required to lay the groundwork for determining options to meet mid- and long-term needs. Significant consideration was given to the potential for demand-side options to help relieve capacity needs in the Kingsville-Leamington area, with specific recommendations for near-term actions to support projects that reduce electricity demand from indoor agriculture or mitigate market barriers.

The focus of this IRRP is to provide customers in the region with adequate line connection and step-down transformation capacity, and maintain a level of reliability consistent with accepted planning standards. A companion bulk study was completed in June 2019[1] that focused on bulk electricity needs; however, information and recommendations in both studies have been integrated as they impact bulk and regional needs.

A key consideration in these analyses is whether near-term actions maintain, or act as a barrier to, long-term options. The near-term actions recommended are intended to be completed before the next IRRP cycle, scheduled for 2025, or sooner, depending on demand growth or other factors. In some cases, the scope of near-term actions includes the continuation of defined planning activities coordinated among key stakeholders to develop and complete recommendations within a specific time period. The completion of these actions will inform decisions for the next scheduled planning cycle, or sooner, particularly around integrated solutions that address multiple needs, as well as demand-side options and capabilities for which sufficient information is not currently available.

This report is organized as follows:

- A summary of the recommended plan for the Windsor-Essex region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the Windsor-Essex region and the study scope are discussed in Section 4;
- The demand outlook scenarios, and energy efficiency and distributed energy resource (DER) assumptions, are described in Section 5;

[1] Refer to the bulk study for details: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/Need-for-Bulk-Transmission-Reinforcement-in-Windsor-Essex-Region-June2019.pdf?la=en

- Electricity needs in the Windsor-Essex region are presented in Section 6;
- Alternatives and recommendations for addressing the needs are described in Section 7;
- A summary of engagement activities to date and moving forward, is provided in Section 8; and
- A conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

The Windsor-Essex IRRP provides recommendations to address the electricity needs of the region considering forecast electricity demand over a 20 year period, based on the application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC).[2]

This IRRP identifies three planning horizons: from the base-year (2017)[3] through the near term (up to 2025), medium term (six to 10 years, through to 2030), and longer term (11 to 20 years, or through to 2037). These planning horizons reflect the inverse relationship between the length of time and demand certainty (in that the longer the outlook, the less certain it is), lead time for electricity resource development, and planning commitment required.

The recommendations in the IRRP are focused on four main categories of needs:

1. Customer supply needs in the Kingsville-Leamington area, where demand is expected to grow at an unprecedented rate,
2. Needs in the nested 115 kV sub-systems,
3. Local capacity, reliability, and end-of-life needs identified within the study area, and
4. Long-term needs.

Substantial effort was made to evaluate the potential of non-wires alternatives (NWAs) to compliment other more traditional methods of supplying capacity.

The IRRP was developed based on a set of planning considerations, including reliability, cost, feasibility, and flexibility. In particular, associated projects recommended by the companion Windsor-Essex bulk study were integrated into the plan.

[2]Refer to ORTAC for details: http://www.ieso.ca/-/media/files/ieso/Document%20Library/Market-Rules-and-Manuals-Library/market-manuals/market-administration/IMO-REQ-0041-TransmissionAssessmentCriteria.pdf

[3] Load forecast data and study work were initiated in late 2017 as a result of rapid growth which triggered an early start to the IRRP process, as detailed in Section 4.

Given the significant forecast demand increase, a number of capacity and load restoration needs were identified. For the Kingsville-Leamington area, the IRRP identifies specific investments, both non-wires and wires, some of which are already being implemented to ensure they are in service in time to address the region's urgent needs.

For the 115 kV sub-systems, the IRRP identified options for an integrated solution that addresses multiple needs. This will maximize the use of existing electricity system assets in the context of the forecast conditions for the study area, while enabling the analysis that needs to be completed before further recommendations can be made.

For the near and medium term needs in local areas, specific recommendations are identified to address capacity, end-of-life and restoration needs, as appropriate.

For the long term, the IRRP identified near-term actions required to monitor demand growth, technology adoption, and industry change, and lay the groundwork for exploring future options. As these needs are not expected to emerge until further in the future, it is not necessary (nor would it be prudent given forecast uncertainty and the potential for technology change) to commit to further reinforcements at this time.

A summary of ongoing work, as well as the recommendations to meet capacity, restoration, and asset replacement needs appear below.

2.1 ONGOING WORK

Due to the age and condition of the transmission infrastructure in the Windsor-Essex region, a number of plans are already underway to address some of the area's end-of-life asset replacement needs. The previous IRRP, released in 2015, recommended the Supply to Essex County Transmission Reinforcement (SECTR) project – an extension of two existing 230 kV circuits from Chatham SS to Keith TS, south to Leamington TS #1. Hydro One's subsequent Regional Infrastructure Plan (RIP) built on this and recommended several end-of-life replacement projects, which were not part of the scope of the 2015 IRRP.

The status of various regional projects at the start of this IRRP is summarized in chorological order in .

Table 2-1. By the time this IRRP was initiated, significant work had already been completed at these stations, with in-service dates ranging from 2018-2021.

Table 2-1: Summary of Ongoing and Recently Completed Work in Windsor-Essex

Station/Line Section	Need	Proposed In-Service Date
Keith TS	• Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to allow for the construction of the Gordie Howe Bridge	2018 (completed)
Leamington TS #1	• A new 230/27.6 - 27.6 kV 75/100/125 MVA transformer station • A 13 km double circuit 230 kV transmission line south to the new TS from the existing 230 kV circuits from Chatham SS to Keith TS	2018 (completed)
Malden TS	• Replacement of end-of-life low voltage breakers.	2019 (completed)
Kingsville TS	• Replacement of end-of-life transformers T2/T4 with 83 MVA T6	2018 (completed)
Leamington TS Expansion	• Expansion of Leamington TS to include two new 230/27.6 - 27.6 kV 75/100/125 MVA transformers	2019
Tilbury TS	• Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply	2020
Kingsville TS	• Replacement of end-of-life transformers T1/T3 with 83 MVA T5	2021

In addition, the IESO recently completed a companion bulk study of the Windsor-Essex region, which recommended new bulk system facilities – a 230 kV double circuit transmission line from Chatham SS to the Leamington Junction – to address the area's near- and mid-term bulk system needs. A hand-off letter[4] was issued to Hydro One requesting initiation of development work for the transmission circuit, with an expected in-service date of winter 2025/2026.

The impact of these projects in terms of station layout and capacity was incorporated into the assessment of the transmission system capability in the Windsor-Essex region.

2.2 KINGSVILLE-LEAMINGTON AREA

The Kingsville-Leamington area is experiencing unprecedented demand growth – approximately 900 MW of new load requests to Hydro One in 2018 alone – driven by rapid expansion in the indoor agriculture and cannabis industries. The recent interest in retrofitting and installing artificial lighting to enhance greenhouse production is driving a large increase in electricity demand in the Kingsville-Leamington area. For this reason, a combination of NWAs and wires options is required to address the significant near-term customer supply needs identified in this area.

1. **Targeted call for innovative projects**

The greenhouse load characteristics in the Kingsville-Leamington area are fairly homogenous but differ significantly from other typical system loads. As a result, they have the potential to fit with demand-side options to manage greenhouse related load growth. Through the Kingsville-Leamington Local Advisory Committee (LAC), a number of potential demand-side solutions were identified, including energy efficiency and demand response (DR). However, a number of factors (i.e., frequency, duration, and magnitude of demand reduction and corresponding impact to crops) pose barriers to their adoption. As a result, the Working Group recommends that the IESO consider a targeted call for applications through the Grid Innovation Fund (GIF)

[4]Refer to the hand-off letter for details: http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/southwest-ontario/Leamington-Transmission-Line-Handoff-Letter-June2019.pdf?la=en

for Q4 2019/Q1 2020. To identify and mitigate market barriers, or otherwise accelerate the adoption of competitive cost-effective solutions to rising electricity demand associated with the growth of indoor agriculture. The call should solicit projects that validate the performance and business case of promising new technologies, practices, and services across the province. This should leverage the work already performed for demand-side options in Kingsville-Leamington and LAC discussions to help scope parameters of the targeted call. The lessons learned from these projects will be applicable across the province, starting with areas such as Dresden and Niagara, which are experiencing significant growth in indoor agriculture.

2. Provincial Energy Efficiency

Under the Interim Framework (2019-2020), the IESO centrally delivers provincial energy-efficiency programs, including the Retrofit Program, Small Business Lighting, and Energy Manager Program. Last year, updates were made to introduce incentives supporting horticulture light applications. Additionally, the IESO is making approximately $27-million available for LDCs to undertake local energy-efficiency programs through the Local Program Fund with priority given to areas where local needs have been identified. While reliability, crop performance, and technology maturity limited mass uptake of light emitting diode (LED) horticulture lighting technology, existing retrofit programs and future programs beyond the Interim Framework should be evaluated to increase participation in areas with identified local need. The Working Group recommends that the IESO communicate developments of future energy-efficiency programs to the local community, as they arise.

3. Monitor Local Generation

To meet supply needs, some load customers are using behind-the-meter generation to offset their baseload consumption and facilitate their supply needs. The amount of generation connected to the electricity grid, whether directly or behind-the-meter, impacts the short-circuit capability of the connecting transformer station. To maintain a holistic view of short circuit limits is maintained, the Working Group recommends ongoing collaboration with the IESO to monitor the growth of local generation in the Kingsville-Leamington area, and inform the next cycle of regional planning.

4. Leamington Switching Station (Lakeshore TS)

Aside from the NWAs recommended above, rapid growth in the Kingsville-Leamington area necessitates additional reinforcements. The stations supplying this load – Kingsville TS and Leamington TS – are forecast to reach their station capacity within the next year. A new switching station at or near Leamington Junction to sectionalize and switch the four existing 230 kV circuits from Chatham to the Windsor area (C21J/C22J/C23Z/C24Z) is recommended to increase the capability of the system to supply load in the Kingsville-Leamington area while contributing to improved performance of the bulk system.

The proposed switching station will improve reliability, and provide some additional local supply capability to connect an additional transformer station in the area and continue supplying load in the Kingsville-Leamington area. The switching station also relieves the need for interim measures, recommended as a near-term action to maintain supply prior to constuction. Given the urgent nature of this need, which was identified in the process of conducting IRRP study work, the IESO issued a hand-off letter to Hydro One recommending that development work for this switching station (officially referred to as Lakeshore TS) be initiated.

5. Interim Measures

While the above actions are recommended to address the near-term capacity need in Kingsville-Leamington, continued reliance on interim measures is required until those reinforcements are in place. Between the 2015 IRRP and the completion of Leamington TS #1 in 2018, the number of customer connection requests (both transmission and distribution) exceeded the capability of the new station and the total 2015 IRRP load forecast for the area.

In response, Hydro One decided to proceed with an expansion of the recently constructed Leamington TS #1 to double the amount of capacity that can be supplied from the station to 400 MW. To accommodate the expansion and the connection of additional transmission customers starting in early 2020, interim measures, such as load rejection through a Special Protection System (SPS), are required resulting in a lower level of reliability to connecting customers than what is typically provided. The need for interim measures during normal operations is alleviated by the proposed switching station, and will be eliminated when the new line between Chatham TS and the switching station come into service by 2022 and the winter of 2025/2026 respectively.

2.3 115 KV SUB-SYSTEMS

A number of capacity, load restoration and asset replacement needs were identified in the 115 kV sub-systems. Given the nested nature of these sub-systems, an integrated solution that considers the broader context of the area and connected 230 kV network would address multiple needs and maximize benefit to the overall system.

1. **Undertake a Comprehensive Study of the 115 kV Sub-system Capacity and Leamington Load Restoration Needs**

Current station capacity needs at Kingsville TS and Lauzon TS, as well as a future supply capacity need in the Lauzon 115 kV sub-system are being managed with interim measures i.e., through an SPS.

Conversion of Kingsville TS from 115 kV to 230 kV may require an integrated option that can address these needs, as well as potentially assisting with Leamington capacity and load restoration needs. Other options include non-wires solutions, or consideration of supply from Keith TS. However, additional supply capability resulting from these options is limited until the completion of the upstream, new 230 kV double-circuit transmission line from Chatham SS to Lakeshore TS, and is impacted by Hydro One Distribution decisions with respect to the schedule and work plan for local customer load connections. For this reason, timing of the solution should occur in the mid-term – 2025/2026 at the earliest, given the expected in-service date of the new 230 kV circuit from Chatham to Lakeshore.

Effectively solving the 115 kV sub-system capacity needs and the Leamington capacity and load restoration needs requires a coordinated, integrated approach. The majority of these needs are primarily driven by growth in a single sector, making it prudent at this time to ensure that the recommendations contained in this IRRP address near-term needs, while maintaining options for mid-term solutions. To maximize the effectiveness of this option, numerous factors need to be considered, including which of the existing 230 kV transmission lines (C21J/C22J/C23Z/C24Z) to connect to, whether to move the station from 115 kV to 230 kV or maintain a 230/115 kV connection, upstream system impacts, and reactive requirements. The load security and restoration needs at Leamington TS are impacted by the plan to supply the 115 kV sub-systems or corresponding buildout of load transfer capability between Leamington and Kingsville. In addition, Lauzon upstream supply capability requirements are sensitive to the configuration of the nearby Kingsville TS, which will impact options for the autotransformers (T1/T2) and step-down transformers (T7/T8) reaching end of life.

Given the rapid growth in the area, collecting more information on supply options and monitoring load growth as it continues to materialize, will effectively expedite work required for the next IRRP cycle. With this preparation in mind, in addition to the many considerations described above, the Working Group recommends that a study of the 115 kV sub-system capacity, end-of-life needs, and Leamington load restoration needs, be completed by Q2 of 2020 as an addendum to the IRRP. A plan for the proposed work is provided in Appendix C.

2.4 OTHER LOCAL NEEDS

Some independent near- and mid-term needs were identified through this IRRP. Specific recommendations are outlined for capacity, end-of-life and restoration needs, where required.

1. **New DESN station in Chatham-Kent**

A near-term capacity need at Kent TS was identified during the development of this IRRP. While Kent TS is outside the original scope of this IRRP, given the urgency of the need and its proximity to the study area, the Working Group decided to include it in the plan. A customer connection request and forecasted growth would fully utilize capacity at the station by 2020. As a result, the Working Group recommends that a new DESN be built south of Chatham proper, to supply this new load growth and potentially provide load transfer capability for existing loads being supplied out of Kent TS.

2. Upsize Keith TS Autotransformers (T11/T12)

The 2015 RIP recommended like-for-like replacement of the aging Keith TS autotransformers. Since then, additional discussions and studies during the Needs Assessment and Scoping Assessment have instead supported an upsizing based on both the minimal incremental cost and the added supply capability to the 115 kV Windsor-Essex network. The Working Group confirms proceeding with the upsizing of the Keith TS autotransformers T11/T12 from 125 MVA to 250 MVA units by 2024.

3. Decommission Keith Step-Down Transformer (T1)

In the 2015 RIP, Hydro One recommended a plan to decommission the step-down transformer Keith T1. As the load on this transformer will be moving from the area by mid-2020, the Working Group recommends that this decommissioning work proceed as planned towards its target date of 2024.

4. Upsize Lauzon Step-Down Transformers (T5/T6)

Lauzon TS T5/T6 step-down transformers are approaching their end of life and are forecast to exceed their transformer capacity. While Lauzon DESN 1 (T5/T6) has more load connected than DESN 2 (T7/T8), balancing the loads would still not address the Lauzon capacity need. The Working Group recommends that Hydro One proceed with an upsizing of the T5/T6 step-down transformers from 83 MVA to 125 MVA.

5. Lauzon Load Restoration

Existing load restoration needs were identified for the loss of the C23Z/C24Z 230 kV supply circuits. In this instance, resupplying Lauzon TS load through the T1/T2 autotransformers and 115 kV network is sufficient to restore the lost load in excess of 150 MW within four hours, satisfying ORTAC planning criteria. The Working Group recommends that no further action be taken with respect to load restoration at Lauzon.

6. **Tilbury Load Security and System Restoration**

Load security and system restoration needs were identified in the Scoping Assessment as areas that would need further assessment. Based on current load forecasts, no reinforcement needs have been identified for Tilbury. Since the transfer of Tilbury TS load to Tilbury West DS in 2020 satisfies ORTAC Section 7 system restoration and load security requirements, the Working Group recommends that no further action be taken with respect to these needs.

2.5 LONG-TERM NEEDS

In the long term, the Windsor-Essex region's electricity demand is projected to continue to grow, based on the IRRP planning forecast presented in Section 5.7. This IRRP sets out the near-term actions required to ensure that options remain available to address future needs in the most efficient and cost-effective way, if and when they ultimately arise.

1. **Monitor Load Growth at Belle River TS**

Belle River TS is forecast to experience moderate load growth over the study period, with a transformer capacity need arising in the mid to long term. Considering the sensitivity to energy efficiency and demand management savings for this station, this IRRP recommends monitoring station load growth between planning cycles to determine whether to proceed with options to increase station capacity in the next planning cycle.

2. **Monitor Load Growth in the Kingsville-Leamington Area**

Unprecedented growth in the Kingsville-Leamington area is driven by a single sector presenting a risk for long-term transmission investments. For this reason, the Working Group recommends that the IESO continue to monitor long-term growth in the area between regional planning cycles to determine when decisions on the long-term plan are required, inform the next cycle of regional planning for the area, and trigger the next cycle early, as required.

3. Monitor Industry Developments

The agriculture industry and emerging technologies are rapidly evolving. The Working Group recommends that the IESO continue to monitor the status of developments in the indoor agriculture industry through the ongoing Greenhouse Energy Profile Study which will explore greenhouse energy usage trends over the next five to 10 years.

4. Monitor Regional and Bulk System Transmission Developments

As identified or recommended in this IRRP, a number of transmission projects are underway in the Windsor-Essex region, both on the regional and bulk level. To ensure that regional and bulk plans adequately meet projected near- and mid-term needs, the Working Group recommends that the IESO monitor and report on the status of Windsor-Essex transmission projects between regional planning cycles.

3. Development of the Plan

3.1 THE REGIONAL PLANNING PROCESS

In Ontario, preparing to meet the electricity needs of customers at a regional level is conducted through regional planning. Regional planning assesses the interrelated needs of a region - defined by common electricity supply infrastructure – over the near, medium, and long term and develops a plan to ensure cost-effective, reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five year planning cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitter(s) and LDC(s) in each planning region.

The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initially screening of a region's electricity needs;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP which provides further details on recommended wires solutions.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

The IESO is currently conducting a Regional Planning Review Process[5] to consider lessons learned and findings from the previous cycle of regional planning and other regional planning development initiatives, such as pilots and studies.

3.2 WINDSOR-ESSEX REGION WORKING GROUP AND IRRP DEVELOPMENT

Development of the Windsor-Essex IRRP was initiated in late 2017 with the release of the Needs Assessment report[6] for the Windsor-Essex region. This product, prepared by Hydro One Transmission with participation from the IESO, E.L.K., Entegrus, ENWIN, EPL and Hydro One Distribution, identified needs requiring coordinated regional planning. To address these needs and ensure resulting solutions were consistent with the decisions made in the first cycle of regional planning, the subsequent Scoping Assessment report[7] – produced by the IESO – recommended that a number of capacity and restoration needs identified be addressed through an IRRP – a decision that reflected both the significant growth forecast, and the potential for non-wires solutions.

In 2018 the Working Group was formed to develop Terms of Reference for this IRRP, gather data, identify near- to long-term electricity needs in the region, and recommend actions to address them.

In tandem, the IESO undertook a bulk report for the Windsor-Essex region. This report was informed by demand forecasts and plans for new connection facilities developed through this IRRP, and solutions for both were integrated as they impact bulk and regional needs.

[5] More information can be found on the IESO regional planning review engagement site: http://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Planning-Review-Process
[6]Refer to the Needs Assessment to learn more: https://www.hydroone.com/about/corporate-information/regional-plans/windsor-essex
[7]Refer to the Scoping Assessment for details: http://ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/2018-Windsor-Essex-Scoping-Assessment-Outcome-Report.pdf?la=en

3.3 LOCAL ADVISORY COMMITTEE

The Kingsville-Leamington Local Advisory Committee was formed as a vehicle for targeted engagement on local priorities in the Kingsville-Leamington area and demand-side options in particular. The LAC, which included representation from local municipalities, members of the agricultural industry, and local energy service providers, offered advice on the nature of the load growth and feedback on potential demand-side options that could impact local needs. The LAC met three times during the IRRP phase of regional planning and the outcomes of its discussions helped inform the Working Group and the recommendations in this IRRP.

Subsequently, a sub-working group was formed to investigate demand-side options, to manage continued growth in the greenhouse sector and better utilize facilities that can be connected while transmission reinforcement options are being developed. This sub-working group consisted of representatives from the IESO, E.L.K., Entegrus, ENWIN, EPL, and Hydro One. It leveraged contacts in the local community, technical experts and other interested parties to gather information and propose options to the Working Group for incorporation into the options evaluation process of this IRRP.

4. Background and Study Scope

This is the second cycle of regional planning for the Windsor-Essex region. When the OEB formalized the regional planning process in 2013, planning work was already underway in Windsor-Essex. As such, the Needs Assessment and Scoping Assessment phases for the first cycle of the regional planning process were deemed to be complete and Windsor-Essex was identified as a "transitional" region within the Group 1 planning regions, the first group to utilize the formalized regional planning process.

In April 2015, the Windsor-Essex IRRP recommended the SECTR project – an extension of two existing 230 kV circuits from Chatham SS to Keith TS, south to Leamington TS #1 to provide an additional 200 MW of winter local load meeting capability. On the basis of this planning report, Hydro One completed the RIP for Windsor-Essex on December 22, 2015.

Between the 2015 IRRP recommendation and the completion of SECTR in 2018, the number of customer connection requests received by LDCs in the area, particularly Hydro One, exceeded both the capability of the new station and the total 2015 IRRP load forecast. This triggered the second cycle of regional planning for Windsor-Essex in mid-2017. A Needs Assessment was published in October 2017, followed by a Scoping Assessment in March 2018. The Scoping Assessment report identified a number of needs requiring further regional coordination, and recommended that both an IRRP be initiated for the Windsor-Essex region, and a separate bulk planning process occur in parallel with the IRRP. The results contained in the *Need for Bulk Transmission Reinforcement in the Windsor-Essex Region*, which was completed on June 13, 2019, have been incorporated into this plan.

Building on past regional studies and taking into account updates to activities in the region and LDCs' load forecasts, this report presents an integrated regional resource plan for the Windsor-Essex region until 2037. In addition to addressing reliability performance and end-of-life asset replacement needs in the region, the IRRP focuses on identifying recommendations to meet near-term customer supply need through a combination of non-wires and wires options. To set the context for this IRRP, the scope of the planning study and the area's existing electricity system are described in Section 4.1.

4.1 STUDY SCOPE

This IRRP develops and recommends options to meet the electricity needs of the Windsor-Essex region in the near, medium, and long term, and assesses any existing or emerging restoration or supply security needs. The plan, prepared by the IESO on behalf of the Working Group, considers the long-term outlook for electricity demand, energy efficiency, transmission and distribution system capability, relevant community plans, development of the regional transmission system, condition of transmission assets, and distributed energy resources.

The following transmission facilities were included in the scope of this study:

- 230 kV connected stations – Malden TS, Keith TS, Lauzon TS, Leamington TS, Kent TS
- 115 kV connected stations – Crawford TS, Essex TS, Walker TS #1, Walker TS #2, Belle River TS, Tilbury West DS, Tilbury TS, Kingsville TS,
- Five customer owned transformer stations on the 115 kV system
- 230 kV transmission lines – C21J/C22J, C23Z/C24Z, J5D
- 115 kV transmission lines – J3E/J4E, Z1E/Z7E, K2Z/K6Z
- 115 kV transmission cables – E8F/E9F
- 230/115 kV auto-transformers at Keith TS and Lauzon TS
- Existing local generation assets

Electricity to Windsor-Essex is supplied from the rest of the province through two 230 kV double circuits and two 115 kV single circuits. The main 230 kV transmission corridor in the region connects with the rest of the province at Chatham SS in the Municipality of Chatham-Kent. Two 230 kV double-circuit lines, C21J/C23Z and C22J/C24Z, run east-west in this corridor, located south of Highway 401, from Chatham SS to the proposed Lakeshore TS, C21J/C22J continues west to Keith and C23Z/C24Z continue northwest to Lauzon. Keith TS provides an interconnection with the Michigan system via 230 kV circuit J5D and an in-line phase shifter.

In Windsor, Keith TS and Lauzon TS, connect the region's 115 kV network to the 230 kV transmission system via two autotransformers at each station. The main 115 kV transmission corridor runs through Windsor from Keith TS through Essex TS to Lauzon TS. The double-circuit line J3E/J4E located in this corridor connects Keith TS with Essex TS, and the double-circuit line Z1E/Z7E connects Essex TS with Lauzon TS. Other 115 kV transmission corridors provide for circuits K2Z and K6Z; 115 kV circuits E8F and E9F are underground cables and provide supply to four ENWIN-owned stations.

Subsequent to the Scoping Assessment, a near-term capacity need was identified at Kent TS. While this was originally considered to be out of scope, given the urgent nature of the need and its relative proximity to the study area, the scope of this IRRP was extended to include Kent TS.

The Windsor-Essex region is supplied by a mix of internal resources (generation connected within Windsor-Essex) and external resources (generation located outside of Windsor-Essex accessed through transmission infrastructure).[8] The existing 230 kV network through the region provides Windsor-Essex with supply from the rest of Ontario, particularly the wind and gas generation resources located east of Chatham. It also offers a strong link with Michigan, allowing for imports and exports to flow through the region. Windsor-Essex is home to a significant amount of installed gas generation, wind generators, and a large solar installation, as well as a number of distribution-connected wind, solar and combined heat and power (CHP) resources. The majority of generation capacity in the region is located close to Windsor.

The Windsor-Essex region and its supply infrastructure are shown in Figure 4-1 and Figure 4-2.

[8] The mixture of resources used to supply the region's and the province's energy needs at any time is determined by the real-time energy market.

Figure 4-1: The Regional Transmission System Supplying Windsor-Essex

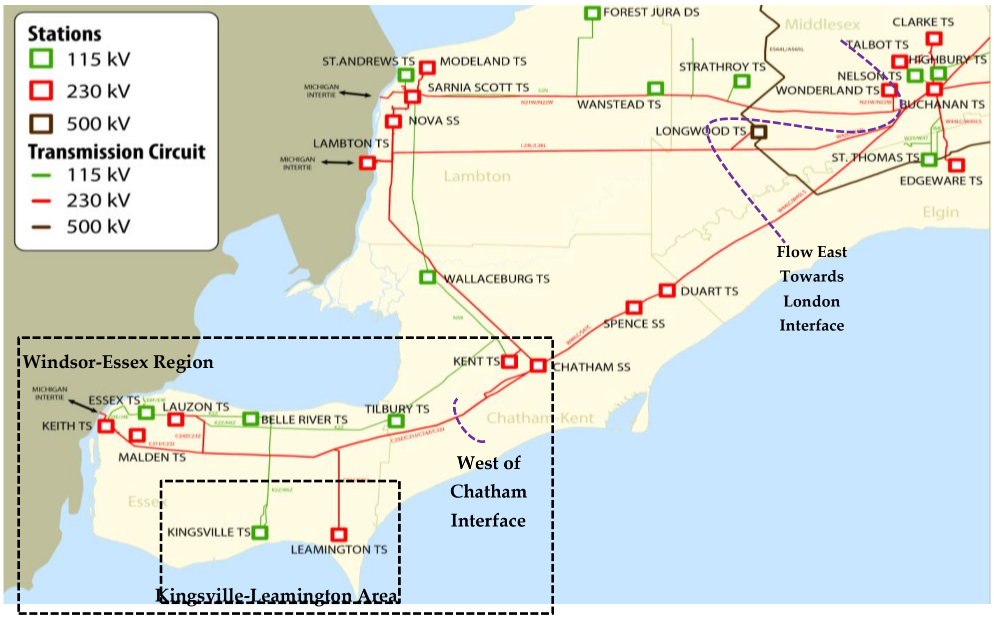
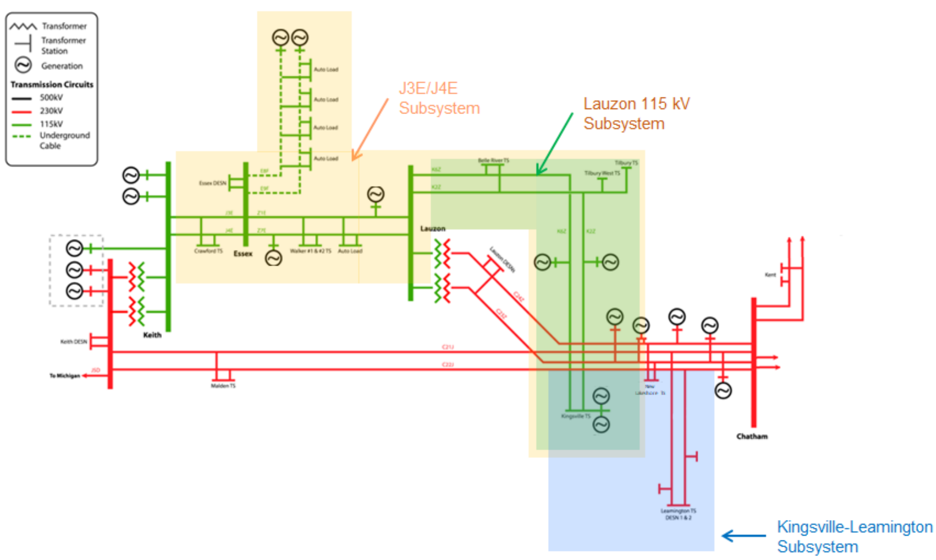


Figure 4-2: The Windsor-Essex Region Electrical Single Line Diagram

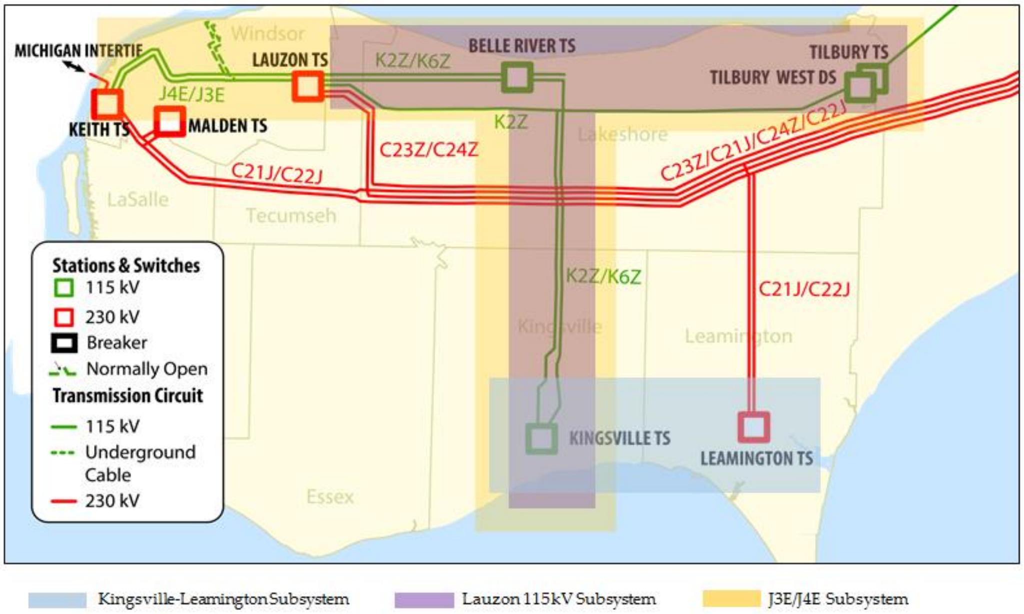


For the purposes of this IRRP, which recommends options to meet the electricity service needs of the Windsor-Essex region, the three nested electrical sub-systems shown in Figure 4-3, are described below:

1. **The J3E/J4E sub-system:** Includes the load that would be supplied via circuits J3E and J4E for the loss of C23Z and C24Z, along with the Lauzon TS DESN loads on C23Z and C24Z which can be resupplied from the 230 kV/115 kV autotransformers post-contingency
2. **The Lauzon 115 kV sub-system:** Includes the transformer stations and generators connected to circuits K2Z and K6Z
3. **The Kingsville-Leamington sub-system:** Includes the load supplied by, and generation connected to, Kingsville TS or the new Leamington TS.

Since the three sub-systems are overlapping, with the Lauzon 115 kV sub-system nested within the J3E/J4E sub-system, the demand for the J3E/J4E sub-system is inclusive of the demand in the Lauzon 115 kV sub-system for the purposes of this plan. Similarly, as the Kingsville-Leamington sub-system partly overlaps both of the other sub-systems, increasing supply to the Kingsville-Leamington sub-system will impact the supply and demand balance in the J3E/J4E and Lauzon 115 kV sub-systems.

Figure 4-3: Windsor-Essex Region Sub-systems



The Windsor-Essex IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand outlook (forecast) and establishing needs over this time frame;
- Examining the load meeting capability (LMC) and reliability of the existing transmission system supplying the Windsor-Essex region, specifically to meet pent-up electrical demand from greenhouse growers in the region, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices;
- Assessing system needs by applying a contingency-based assessment and the reliability performance standards for transmission supply described in Section 7 of ORTAC;
- Confirming identified end-of-life asset replacement needs and timing with the transmitter;

- Establishing feasible integrated alternatives to address needs, including a mix of energy efficiency, generation, transmission and distribution facilities, and other electricity system initiatives;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating options using decision-making criteria that include: technical feasibility, cost, reliability performance, flexibility, environmental and social factors; and
- Developing and communicating findings, conclusions and recommendations within a detailed plan.

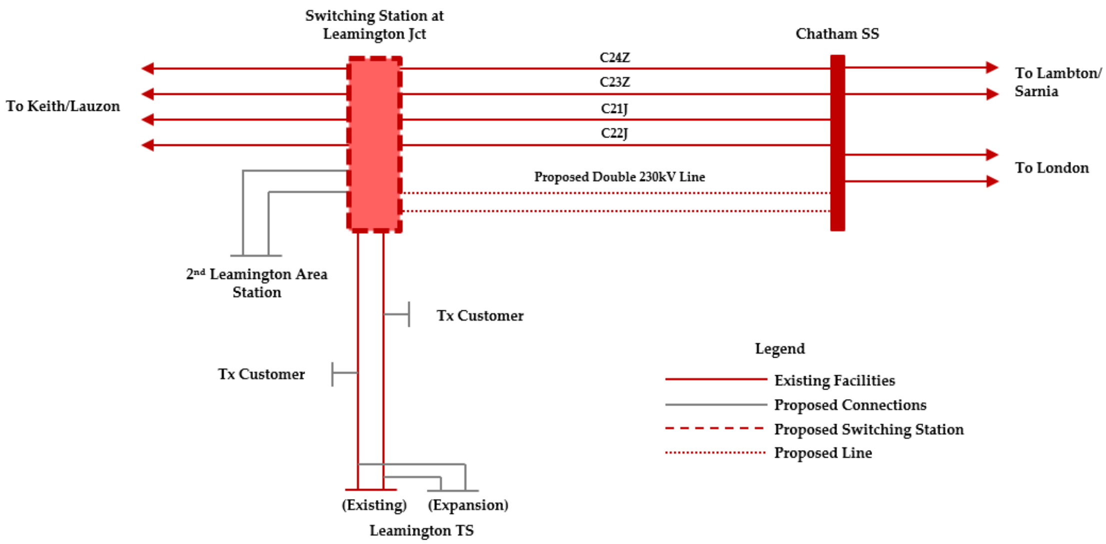
4.2 RECENT, PLANNED, AND COMMITTED RESOURCES

4.2.1 Transmission and Distribution Facilities

In April 2015, the IESO published an IRRP for the Windsor-Essex region, which recommended the SECTR project, which came into service in early 2018. In response to the subsequent number of customer connection requests, Hydro One expanded Leamington TS #1 (Leamington TS #2, with a targeted in-service date of early 2020), to double the amount of capacity that can be supplied from the station to 400 MW. Concurrently, the IESO and Hydro One also received a number of requests – totaling about 100 MW – from larger customers wanting to connect to the new Leamington transmission line. The existing transmission system is unable to accommodate these requests while meeting required planning criteria. Interim measures have been identified to allow the connection of some new facilities and will be included as part of the recommendations of the System Impact Assessments (SIAs) for these projects.

Published in June 2019, a companion report on the bulk transmission system for the Windsor-Essex region recommended a new 230 kV double circuit transmission line from the existing Chatham SS to the new switching station at the Leamington Junction, as shown in Figure 4-4.

Figure 4-4: Single Line Diagram of Existing and Proposed Facilities in the Leamington Area

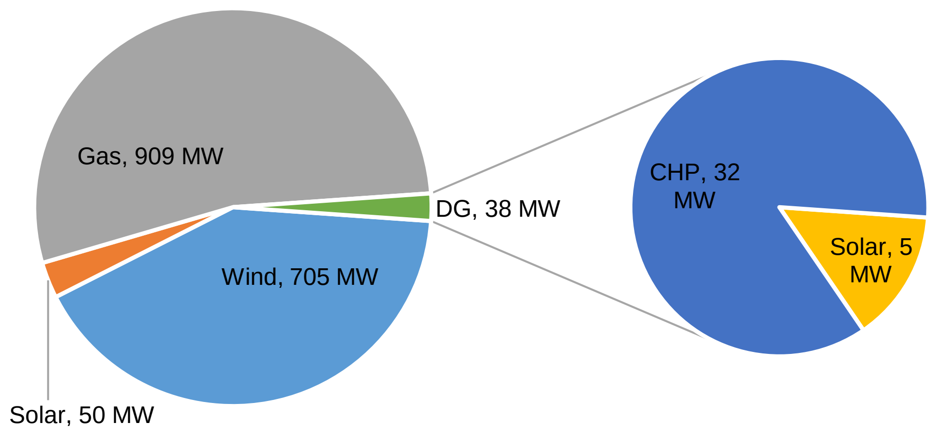


This line will increase the overall transfer capability of the bulk transmission system west of Chatham to reliably supply the forecast load growth in the Kingsville-Leamington area and the broader Windsor-Essex region in the near- to mid-term, permit the resources and bulk facilities in this region to operate efficiently for local and system needs, and maintain existing interchange capability on the Ontario-Michigan interconnection between Windsor and Detroit.

4.2.2 Generation Resources

The region is home to a significant amount of large natural gas generation (including a large combined-cycle plant and a number of CHP generators), wind generators, and a large solar installation in the region, as well as some distributed generation (DG) – primarily CHP and solar. These resources represent a combined total of 1,700 MW of installed generation capacity. Figure 4-5 shows the installed resource mix (transmission-connected and distribution-connected) in the Windsor-Essex region in 2020.

Figure 4-5: Installed Resources in the Windsor-Essex Area for 2020 by Resource Type (Type, MW)

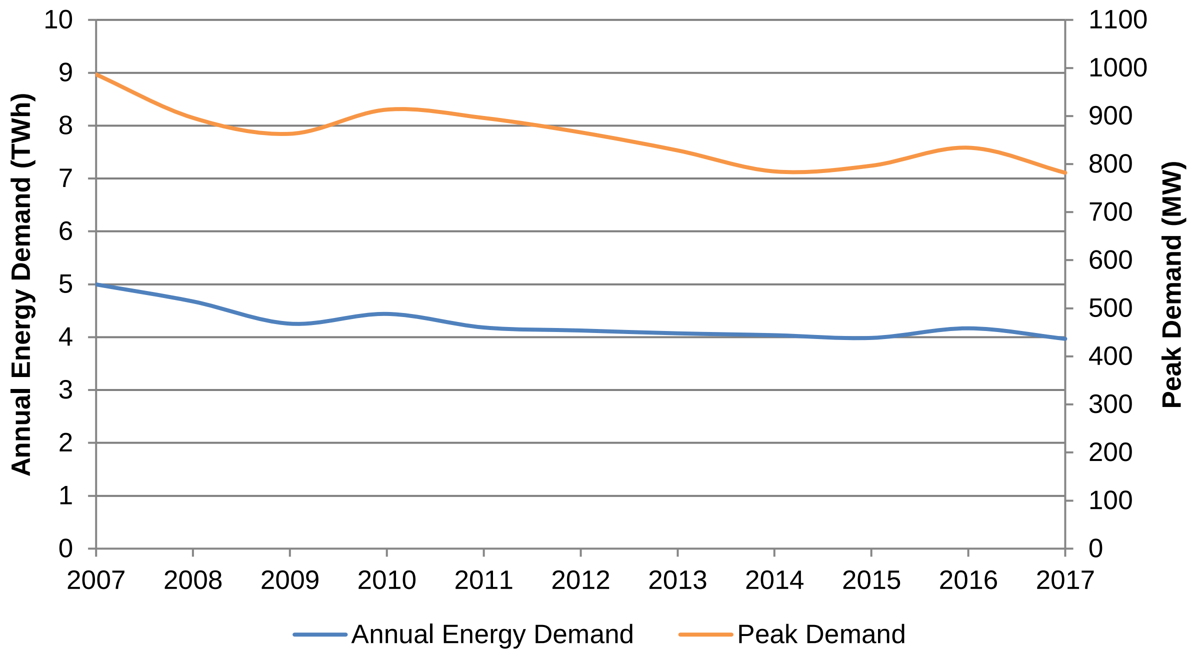


5. Demand Outlook

5.1 HISTORICAL DEMAND

Historically, the electric system in the Windsor-Essex region has been summer-peaking, with the primary load centre being the city of Windsor. Over the past five years, the annual energy requirements and coincident peak demand in the region were around 4 TWh and 800 MW, respectively. As seen in Figure 5-1, prior to 2008 and the subsequent transition from heavy manufacturing to less energy-intensive industries, demand peaked at around 1,000 MW, before decreasing to current levels (less than 800 MW).

Figure 5-1: Historical Summer Demand and Energy Consumption for the Windsor-Essex Region



While the city of Windsor and surrounding municipalities constitute the majority of the geographical area covered by the Windsor-Essex planning region, their loads continue to exhibit relatively flat load growth. In contrast, demand in the Kingsville-Leamington area has increased at an unprecedented rate. As explained in more detail in Section 5.2, this growth has been driven by expansion of the greenhouse sector, which was the key trigger for this planning cycle. Because of the magnitude, geographical concentration, and unique and winter-peaking nature of this load growth, this IRRP distinguishes the planning forecast for the Kingsville-Leamington area from the planning forecast for the broader Windsor-Essex region. Further greenhouse load growth occurring in the Kent area has also been included in this IRRP due to its near-term timing and proximity to the Windsor-Essex region.

5.2 CURRENT DRIVERS OF LOAD GROWTH

The growth in Kingsville-Leamington is driven by rapid expansion in the indoor agriculture and cannabis industries. An understanding of the economic and technological drivers of this growth is important to both manage the build-out of infrastructure reinforcements, and to evaluate potential demand-side options. Additionally, indoor agriculture loads are significantly different from other industrial, commercial, and residential loads in the province. Their unique characteristics, which are described in greater detail below, offer both opportunities for greater efficiency and challenges for the electricity system.

The concentration of indoor agriculture in Windsor-Essex owes much to the region's natural advantages. Its proximity to the Windsor-Detroit border crossing is ideal for supplying both the Canadian and U.S. markets, and its southern latitude and climate provide optimal conditions for agricultural activities. Windsor-Essex also hosts an established ecosystem of support industries and partners, including agriculture research and greenhouse fabrication facilities, which further encourage greenhouse growth in the area.

In recent years, economic factors such as rising consumer demand for year-round local produce and supply disruptions in other markets, have paved the way for an extension of the crop growing season into the winter months. This has led to the proliferation of artificial horticulture lighting, the primary driver for electricity demand growth in Kingsville-Leamington. Rapid local expansion of the cannabis industry, which typically requires energy-intensive lighting and

HVAC systems, following legalization has coincided with the agricultural industry's winter lighting growth.

High-pressure sodium (HPS) lamps are the dominant artificial horticulture lighting technology in agricultural applications driving this load growth. Typical lighting intensity requirements result in an energy intensity of approximately 0.5 MW per crop acre with some variation between crops. Non-lighting loads, such as motorized equipment, make up a very small share of the overall electricity usage. LED lamps have seen limited adoption in agricultural and cannabis applications. Typical cannabis energy intensity is approximately 1 MW per acre and includes significantly higher non-lighting loads such as HVAC and other climate control systems.

5.3 DEMAND FORECAST METHODOLOGY

For the purpose of the IRRP, a 20-year planning forecast was developed to assess electricity supply and reliability needs. Transmission infrastructure supplying an area is sized to meet peak-demand requirements (rather than energy demand requirements). Peak demand requirements are first determined at the station or DESN[9] level, allowing capability in pockets where there is load growth, or where existing equipment has been historically close to its load supply capability, to be more accurately assessed. These forecasts are then aggregated to understand the limits of the transmission system and identify overall regional electricity needs during regional coincident peak times.

The planning forecast is divided notionally into four time horizons: present day, near, medium, and long term. The near term (one to five years) has the highest degree of certainty; any near-term needs are typically met using regional transmission or distribution solutions. Other methods (i.e., conservation and demand management (CDM) or DG) are considered in the near-

[9] A dual-element spot network, or DESN, refers to a standard station layout used throughout the province, where two supply transformers are configured in parallel to supply one or two low-voltage switchgear which the distributor uses to supply load customers. This paralleled dual supply ensures a standard level of reliability where one supply transformer can be lost due to an outage or planned maintenance but supply to the customer can be maintained. A single local transformer station can have one, two, or more individual DESNs.

to mid-term (five to 10 years), since lead times to develop and incorporate these options depend on the size of the need.

The long-term forecast covers the 10- to 20-year period and has the lowest degree of certainty. It is used to identify potential longer-term needs, and for the consideration and development of integrated solutions, including CDM, DG, and major transmission upgrades. Early identification of potential needs and possible solutions enables engagement with the local community and all levels of government long before the need is triggered, maximizes opportunities for input to inform decision-making, and helps ensure local planning can account for new infrastructure.

To address the long-term uncertainty in the electricity demand outlook, the robustness of the existing system was assessed to determine the capability of the existing system and its ability to supply customers, given possible outages and system states (e.g., contingencies).

Additional details on the demand outlook assumptions can be found in Appendix B. The demand outlook was used to assess any growth-related electricity needs in the region.

5.4 GROSS DEMAND FORECAST

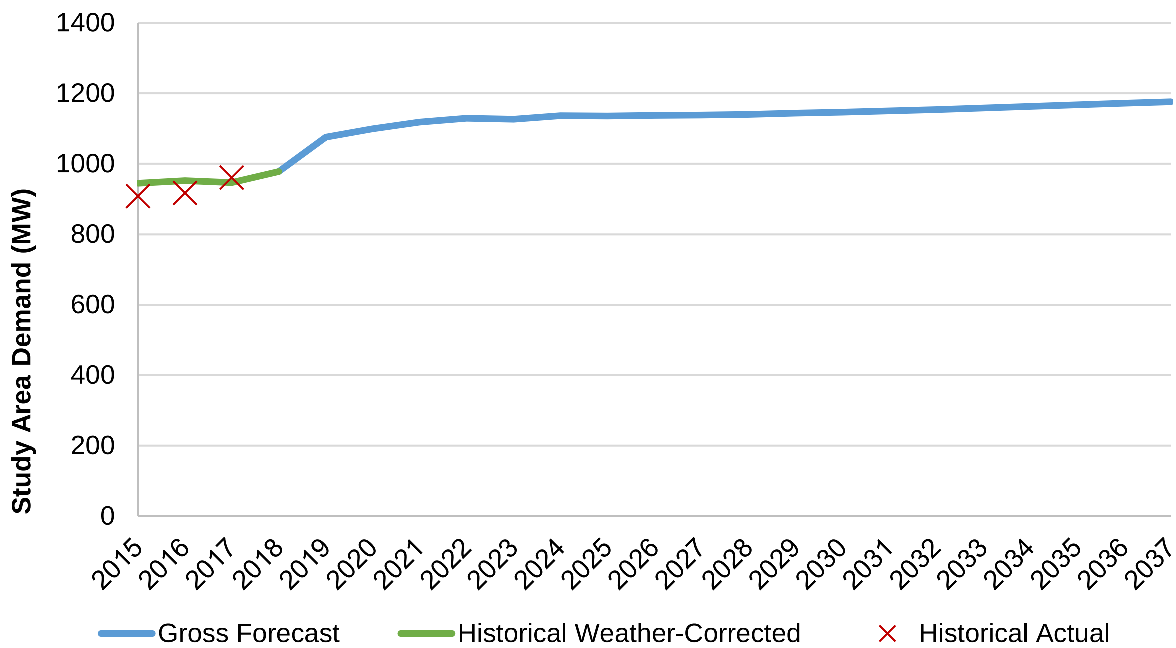
The Working Group prepared a gross demand outlook for each of their service areas within the Windsor-Essex region at the transformer station level, or at the station bus level for multi-bus stations.[10] Gross demand forecasts account for increases in demand from new or intensified development, but not for the full impact of future energy-efficiency measures such as codes and standards and DR programs. However, LDCs are expected to account for changes in consumer demand resulting from typical energy efficiency improvements and response to increasing electricity prices, which is known as "natural conservation."

[10] Often transformers will supply multiple buses at a station. As the amount of load that a transformer can supply will vary based on how load is shared between buses, it can often be useful to have a bus level forecast depending on the nature of the capacity needs in an area.

Thanks to their direct relationship with customers, LDCs have the best information on customer and regional growth expectations in the near and medium term. Other common considerations include known connection applications and typical electrical demand for similar customer types. More details on demand outlook assumptions can be found in Appendix B.

The graph in Figure 5-2 shows the gross demand outlook for the Windsor-Essex region under median weather conditions. This was developed through forecasts provided by the Working Group up to Leamington DESN 1 and 2, combined with historical data points for comparison. The planning forecasts in Section 5.7 break this forecast into smaller areas, as appropriate.

Figure 5-2: Windsor-Essex Region Demand Outlook (Summer Gross Forecast)



These forecasts are based upon the best available information at the time of this IRRP and will be updated going forward as appropriate. The gross demand forecast by station is provided in Appendix B.

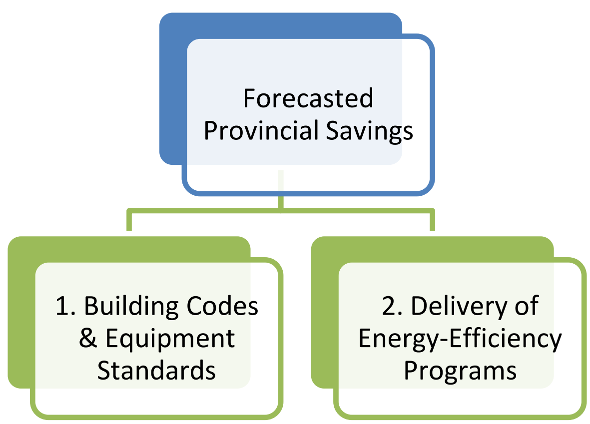
5.5 ENERGY EFFICIENCY ASSUMED IN THE FORECAST

Energy efficiency is achieved through a mix of program-related activities, and mandated efficiencies from building codes and equipment standards. It plays a key role in maximizing the use of existing assets and maintaining reliable supply by offsetting a portion of a region's growth, and helping to ensure demand does not exceed equipment capability. The energy efficiency savings forecast for the Windsor-Essex region have been applied to the gross peak-demand forecast for median weather, along with DG resources (described in Section 5.5), to determine the net peak demand for the sub-region.

Future energy-efficiency savings for the Windsor-Essex region have been applied to the gross peak-demand forecast to take into account both policy-driven and funded energy efficiency through the Interim Framework (estimated peak demand impacts due to program delivery to the end of 2020), as well as expected peak demand impacts due to building codes and equipment standards for the duration of the forecast. As policy related to future provincial energy-efficiency activities changes, the forecast assumptions will be updated accordingly.

To estimate the peak-demand impact of energy-efficiency savings in the sub-region, the forecast provincial savings were divided into two main categories:

Figure 5-3: Categories of Energy Efficiency Savings



1. *Savings due to building codes & equipment standards*
2. *Savings due to the delivery of energy-efficiency programs*

For the Windsor-Essex region, the IESO worked with the LDCs to establish a methodology to assess the estimated savings for each category, which were further subdivided by customer sector: residential, commercial and industrial. This provides a better resolution for the forecast energy efficiency, as energy efficiency potential estimates vary by sector due to differing energy consumption characteristics and applicable measures.

For the Windsor-Essex region, LDCs provided both their gross-demand forecast and a breakdown of electrical demand by sector for each TS. Once sectoral gross-demand at each TS was estimated, peak-demand savings were assessed for each energy efficiency category – codes and standards, and energy-efficiency programs. Due to the unique characteristics and available data associated with each group, estimated savings were determined separately. The final estimated energy efficiency peak-demand reduction, 46 MW by 2037, was applied to the gross demand to create the planning forecast. Table 5-1 provides the peak-demand savings for a selection of the forecast years.

Table 5-1: Peak Demand Savings from Energy Efficiency, Select Years, in MW

Year	2020	2025	2030	2037
Savings (MW)	27	38	44	46

Additional energy efficiency forecast details are provided in Appendix B.

5.6 DISTRIBUTED GENERATION ASSUMED IN THE FORECAST

There are several DG resources in the Windsor-Essex region and that number increased with the introduction of the *Green Energy and Green Economy Act, 2009*, and the associated development of Ontario's Feed-in Tariff (FIT), MicroFIT, and CHP Programs.

The effects of projects that were already in-service prior to the base year of the forecast were not included as they are already embedded in the actual demand, which is the starting point for the forecast. Potential future (but uncontracted) DG uptake was not included and is instead considered as an option for meeting identified needs.

Based on the IESO contract list as of May 31, 2018, new DG projects are expected to offset an incremental 34 MW of peak demand within the Windsor-Essex region by 2020. The distribution-connected contracted generators included in the forecast comprise a mix of solar and CHP. The majority of these generators in the region are CHP (86% of contracted capacity), with solar accounting for 14% of the remaining contracted capacity. Capacity contribution factors of 98% and 37% (CHP and solar respectively) to the regional peak have been assumed to account for the expected output of the mix of local generation resources during summer peak conditions.

Additional information on the regional demand impacts from DG are provided in Appendix B.

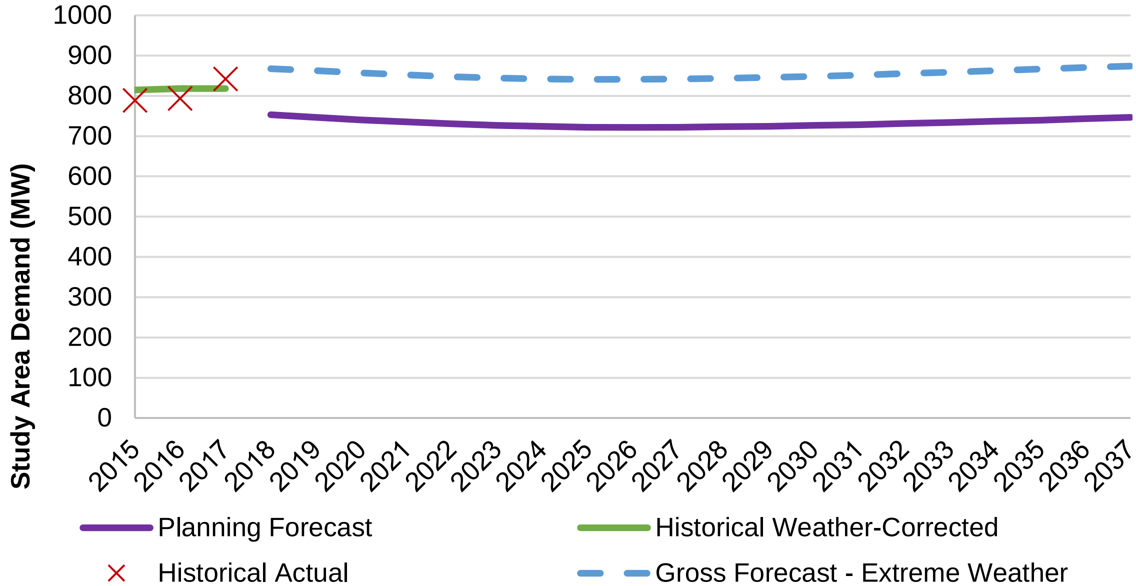
5.7 PLANNING FORECASTS

After taking into consideration the combined impacts of energy efficiency and DG, a 20-year planning forecast was produced for the Windsor-Essex region excluding the Kingsville-Leamington area. The following subsections also describe the demand outlook separately for the Kingsville-Leamington and Kent areas due to the significant and unique nature of load growth.

5.7.1 Windsor-Essex Region

Overall, recent historical demand in the traditionally summer-peaking Windsor-Essex region has been relatively flat, with the majority of the load continuing to exhibit modest growth. Figure 5-4 illustrates the planning forecast, along with historic demand in the area. This planning forecast and for comparison, the gross-demand forecast, have been adjusted for extreme weather conditions. Further information on the planning forecast scenarios are provided in Appendix B.

Figure 5-4: Windsor-Essex Region Summer Planning Forecast (Excluding Kingsville TS and Leamington TS)



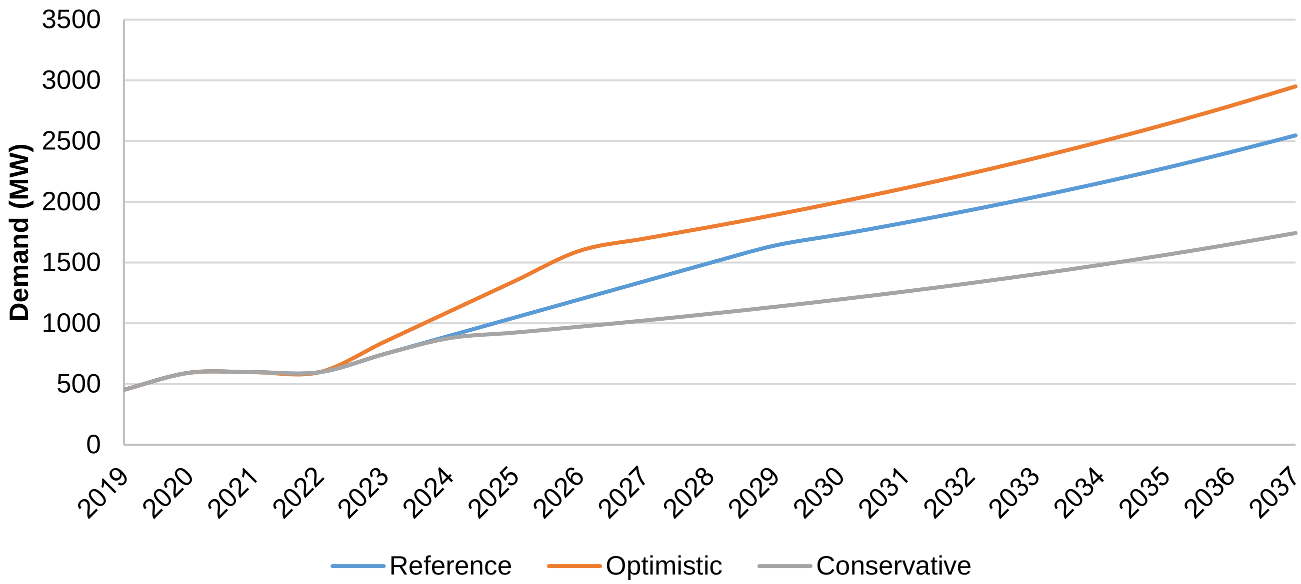
5.7.2 Kingsville-Leamington Area

For loads in the Kingsville-Leamington area, the winter peak forecast is expected to approximately double within the next five years. This is related to the rapid expansion of agricultural businesses, as described in detail in Section 5.2. Highlighting this unique growth separately from the rest of the Windsor-Essex region, three load growth scenarios are shown in Figure 5-5 for the Kingsville-Leamington area. These scenarios were developed based on a number of considerations:

- Customer connection requests to the distribution system received by area LDCs;
- Historical rate of acreage expansion of greenhouses;
- Customers requesting a connection to the transmission system;
- Expansion of other necessary infrastructure to support greenhouse growth in the area (e.g. gas infrastructure, water and waste water servicing); and

– Rate at which new transmission infrastructure can be built.

Figure 5-5: Kingsville-Leamington Area Demand Forecast (Winter-Peaking)[11]



Indoor agricultural and cannabis electricity load profiles differ greatly from historical provincial electricity consumption patterns. Figure 5-6 and

Figure 5-7 illustratively show the forecast agricultural and cannabis load profiles compared with the rest of the Windsor-Essex region in the summer and winter, respectively.

[11] For the purpose of assessing incremental need in the Kingsville-Leamington area, the proposed switching station at the Leamington Junction is assumed to be in place. This switching station relieves the need for interim measures and allows additional load connections to be accommodated up to the capability of the bulk system to supply. For all scenarios in Figure 5-7, the load forecast plateaus until 2022, after which the switching station is presumed to be in service.

Figure 5-6: Sample Hourly Profile for Winter Peak Day

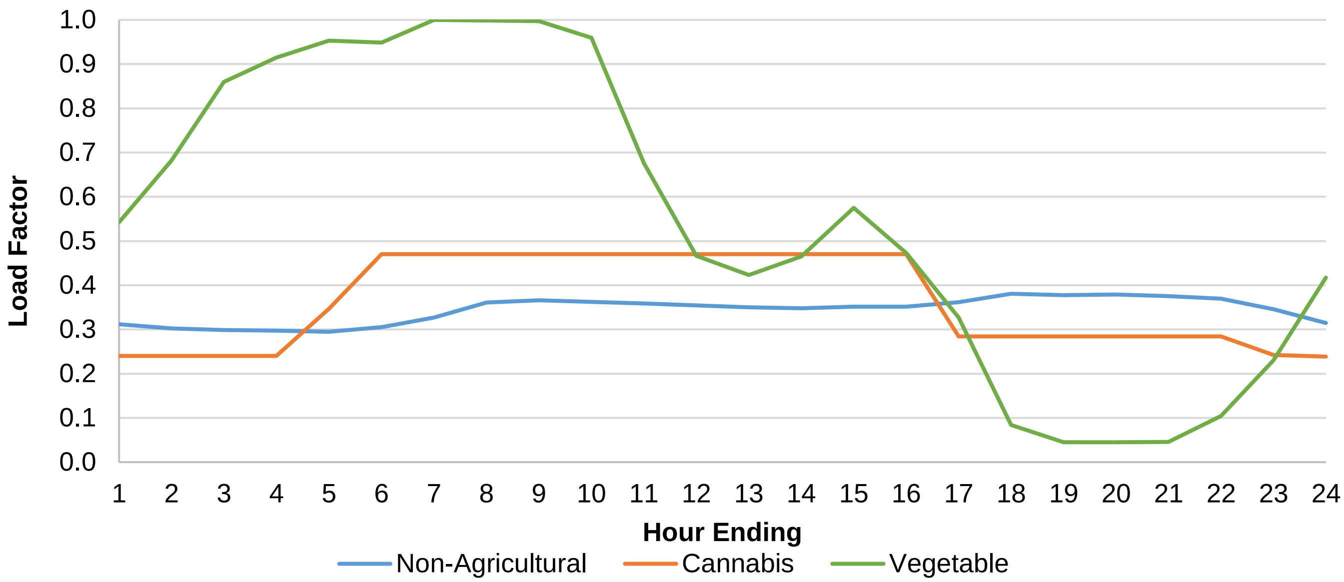
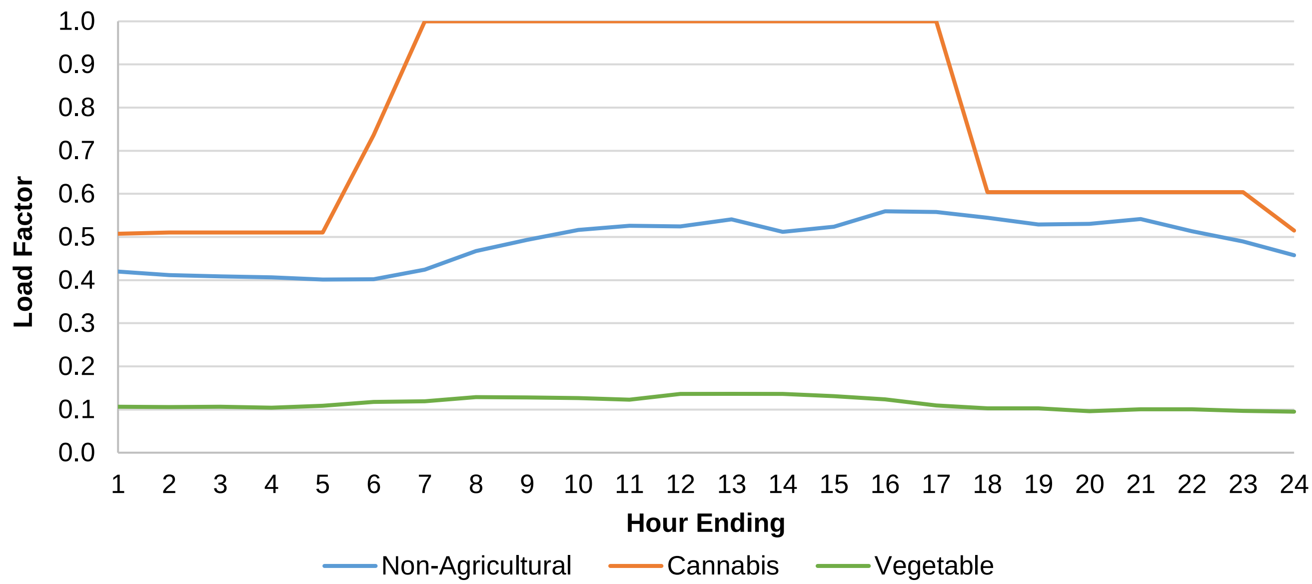


Figure 5-7: Sample Hourly Profile for Summer Peak Day



Indoor agriculture loads are typically winter-peaking, generally from September to April, when artificial lighting is employed to compensate for lower solar insolation during the day and extend lighting hours into the early morning and late evening. While lighting schedules vary among agricultural facilities, the aggregate load profile for all agricultural loads in the area peaks in the winter morning hours between 6 a.m. to 10 a.m.

Cannabis loads peak uniformly throughout the year and exhibit stepwise jumps in load. Cannabis lighting schedules, in combination with HVAC and other non-lighting loads, result in relatively flat daily load profiles with sustained demand for approximately 18-hour intervals.

The energy profiles shown in Figure 5-6 and

Figure 5-7 were used to better understand the local supply requirements and potential to use demand-side options. Further details on the development of an hourly forecast are provided in Appendix B.

5.7.3 Kent Area

Load in the Kent area has been relatively flat over the last several years. However, recently a new 55 MW load approximately 6 km southwest of Kent TS has requested to be connected. Aside from this, growth in public facilities, housing, and the small commercial sector is occurring at a higher rate than recent years, which is projected to result in an additional 12.5 MW of load growth over the next five years.

6. Needs

Based on the demand outlook, system capability, consideration of transmission investments underway, application of provincial planning criteria, and the transmitter's identified end-of-life asset replacement needs, the Windsor-Essex IRRP Working Group determined electricity needs in the near, medium, and long term. This section describes end-of-life, capacity, and reliability needs in the Windsor-Essex region.

6.1 NEEDS ASSESSMENT METHODOLOGY

ORTAC, the provincial standard for assessing the reliability of the transmission system, was applied to assess supply capacity and reliability needs. ORTAC includes criteria related to the assessment of the bulk transmission system, as well as local or regional reliability requirements (see Appendix C for more details).

In applying these criteria, three broad categories of needs were identified:

- **Station Capacity** describes the electricity system's ability to deliver power to the local distribution network through regional step-down transformer stations. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by the station equipment. Station ratings are often determined based on the 10-day limited time rating (LTR) of a station's smallest transformer(s), under the assumption that the largest transformer is out of service.[12]
- **Supply Capacity** is the electricity system's ability to provide continuous supply to a local area. This is limited by the LMC of the transmission supply to the area. The LMC is determined by evaluating the maximum demand that can be supplied to an area accounting for limitations of the transmission element(s) (e.g., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC. LMC studies are conducted using power system simulations analysis (see

[12] A transformer station can also be limited when downstream or upstream equipment (e.g., breakers, disconnect switches, low voltage bus, high voltage circuits) are undersized relative to the transformer rating.

Appendix C for more details). Supply capacity needs are identified when the peak demand for the area exceeds the LMC.

- **Load Security and Restoration** is the electricity system's ability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as the loss of a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements prescribed by ORTAC are described in Appendix C.

The Needs Assessment also identifies requirements related to equipment end-of-life activities. End-of-life asset replacement needs are identified by the transmitter and consider a variety of factors, such as asset age, the asset's expected service life, risk associated with the failure of the asset, and its condition. Replacement needs identified in the near and early mid-term timeframe would typically reflect the assessed condition of the assets, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.

6.2 POWER SYSTEM NEEDS

During completion of the Needs Assessment for the Windsor-Essex region IRRP, the Working Group identified three main categories of needs: (1) local station supply capacity needs, (2) local load security and reliability needs, and (3) end-of-life asset replacement needs. The station supply capacity needs are further characterized within Section 6.2.1.6 in order to properly assess non-wires options.

6.2.1 Local Supply Capacity Needs

Capacity needs, both existing and in the long-term, were identified in the Windsor-Essex region at the station level. These are summarized in Table 6-9, and described in detail in the sub-sections below.

6.2.1.1 Kingsville-Leamington Sub-system Capacity Needs

The Kingsville-Leamington sub-system is experiencing rapid electricity demand growth greatly exceeding both transformer capacity at Kingsville TS and Leamington TS as well as the transmission supply capability into the area. At the time of writing, there is more than 1,300 MW of load seeking connection in this sub-system above the fully utilized Kingsville TS and Leamington TS. Due to the nature of the load growth, the sub-system is expected to be winter peaking; all loading and capacity values below refer to the winter peak.

While load growth is distributed throughout the area, the sub-system is electrically supplied from two separate paths:

(1) Kingsville TS is supplied from 115 kV circuits extending radially from the Lauzon sub-system.
(2) Leamington TS is supplied from the radial 230 kV circuits at the Leamington Junction connected to the upstream C21J/C22J 230 kV circuits.

Kingsville TS loading is already beyond its LTR and is further limited by the Lauzon sub-system LMC. Kingsville TS capacity needs will be described in further detail in Section 6.2.1.2.

The capacity needs in the Leamington area have three nested levels. First, there is a station capacity need, which refers to capacity constraints at the step-down transformer station. Leamington TS has been fully allocated from its in-service date up to the transformer LTR of 200 MW. The Leamington TS expansion, scheduled to be completed by 2020, will increase the LTR to 400 MW but is expected to be fully allocated on its in-service date. Second, there is a supply capacity need on the Leamington "tap," which refers to local transmission constraints that limit the amount of load served from the circuits between Leamington Junction and Leamington TS. The LMC of the tap is 370 MW and is limited by voltage change and decline issues[13] at Leamington TS. Additionally, there are two transmission connected customers

[13] See Appendix C.9.2 for details

seeking connection on the Leamington tap totaling approximately 100 MW. Lastly, there is bulk system capacity need which, in the context of the Windsor-Essex region, refers to the capability of the four 230 kV bulk system circuits westward from Chatham to deliver power to the entire region. The identification and study of bulk system needs include other considerations such as generation behaviour, flow distribution, and imports/exports patterns that are broader than the scope of this IRRP. For more information on the bulk system need, please refer to the *Need for Bulk Transmission Reinforcement in the Windsor-Essex Region* report.

Table 6-1: Kingsville-Leamington Sub-system Capacity Needs

Station(s)	Description	Timing
Kingsville-Leamington Sub-system	A supply capacity need was identified for the load cumulatively supplied by the 115 kV circuits extending radially from the Lauzon sub-system and the radial Leamington tap connected to the upstream C21J/C22J 230 kV circuits.	Today

6.2.1.2 Lauzon Sub-system Capacity Needs

Several local capacity needs were identified in, or related to, the Lauzon 115 kV sub-system within the Windsor-Essex region. These needs are summarized in Table 6-2 and described in detail in the sub-section that follows.

Table 6-2: Lauzon 115 kV Sub-system and Lauzon TS Capacity Needs

Station(s)	Description	Timing
Kingsville TS	An existing station capacity need was identified for the load served by Kingsville TS	Today
Lauzon DESN 1	An existing transformer capacity need was identified for the load supplied by Lauzon DESN 1	Today
Lauzon TS (DESN 1 and 2)	An existing station capacity need was identified for the total load supplied by Lauzon TS	Today
Lauzon 115 kV Sub-system	A supply capacity need was identified for the load cumulatively supplied by Kingsville TS, Belle River TS, and Tilbury West DS	2023

Following its end-of-life refurbishment by 2021, Kingsville TS will comprise two 115 kV/27.6 kV transformers supplying low-voltage switchgear at a distribution voltage of 27.6 kV. With this configuration, the station has a total load meeting capability of 95 MW, limited by voltage change violations of ORTAC Section 4.3 for the loss of the upstream K2Z circuit. According to the winter planning forecast, this station capability is exceeded today and is currently managed by an SPS.

The limiting contingency and phenomenon described above also restricts the LMC of the previously-defined Lauzon 115 kV sub-system that encompasses the loads served collectively by Kingsville TS, Belle River TS, and Tilbury West DS. Assessing these stations served by the K2Z and K6Z circuits together, the sub-system capacity is 157 MW, and according to the planning forecast, is exceeded in 2023.

Related, though supplied by the 230 kV C23Z and C24Z circuits rather than the 115 kV sub-system, are the current capacity needs at Lauzon TS. In addition to the end-of-life needs for all Lauzon TS step-down transformers (further described in Section 6.2.3.1), there is a capacity need specifically for the T5/T6 step-down transformers at Lauzon DESN 1. Moreover, the total station capability for Lauzon TS is further restricted to 190 MW – beyond this cumulative load level, the contingency of a loss of a CxZ circuit results in voltage change violations at

Lauzon TS. These load meeting capabilities reveal station capacity needs that exist today according to the planning forecast, also currently managed by the SPS.

6.2.1.3 J3E/J4E Sub-system Supply Capability

Several local capacity concerns were assessed in the J3E/J4E sub-system within the Windsor-Essex region. While no needs were found during the study period, key issues are summarized in Table 6-3, and described in detail in the sub-section that follows.

Table 6-3: J3/4E Sub-system Supply Capability

Circuit	Description	Timing
J4E	Load supply to all stations in the J3E/J4E sub-system is thermally limited by flow on the J4E circuit	N/A

Currently serving 415 MW and exhibiting less than a 1% year-over-year growth rate, the summer peak for all loads served in the J3E/J4E sub-system reaches 432 MW by the end of the study period. The reliability of supply to this sub-system is especially impacted by the capability of the double-circuit 230 kV circuits J3E and J4E connecting Keith TS and Essex TS, as well as local gas generation east of this transmission corridor in the city of Windsor.

Supply capability to the J3E/J4E sub-system is most limited in two scenarios:

(1) A C23Z/C24Z outage, in which the entire 115 kV network must be supplied through the J3E/J4E circuits, or
(2) A contingency of J3E, in which J4E (which has a lower LTE) is thermally overloaded.

In both scenarios, because the LMC of the sub-system is greater than the planning forecast load, no need is indicated during the IRRP study period.

Closely related to the J3E/J4E supply capability is the load restoration capability to Lauzon TS, as elaborated on in Section 6.2.2.2.

6.2.1.4 Kent Transformer Capacity Needs

A local capacity need was identified in the Kent TS within the Windsor-Essex region. Kent TS currently consists of two DESNs connected to the 230 kV system, which supply load at 27.6 kV. The T1/T2 DESN has a summer capacity of 153 MVA, while the T3/T4 DESN is 58.7 MVA. Based on historical non-coincident loading, the Kent TS currently has approximately 30 MW of capacity remaining. A new 55 MW load approximately 6 km from Kent TS is requesting connection and a SIA has been submitted for the part of this load that can be connected to the existing station. Hydro One and Entegrus are currently working through feeder and protection setting changes required to accommodate the additional loading at Kent TS up to the current capability of the station. Aside from this, growth in public facilities, housing, and small commercial is happening at a higher rate, which is projected to result in an additional 12.5 MW of load growth over the next five years. As a result, Kent TS will be fully committed by the end of 2020, with a capacity need of 31-37 MW remaining, between 2020 and 2027.

Table 6-4: Kent TS Capacity Needs

Station(s)	Description	Timing
Kent TS	A new supply capacity need was identified for additional load to be served by Kent TS	2020

6.2.1.5 Belle River Transformer Capacity Needs

Belle River TS currently consists of a single DESN (T1/T2) connected to the 115 kV circuits K2Z and K6Z, supplying low-voltage switchgear at a distribution voltage of 27.6 kV. This station has a total capacity of 60 MVA or approximately 54 MW. Supplying a peak summer demand of around 45 MW today, Belle River TS is expected to serve a moderately increasing load with a yearly growth rate of up to 2.5 per cent throughout the study period. While sensitive to power factor assumptions and the energy-efficiency forecast, the T1/T2 transformer capacity is expected to be exceeded by approximately 10 MW by 2037, with a need first arising in 2028.

Table 6-5: Belle River TS Capacity Needs

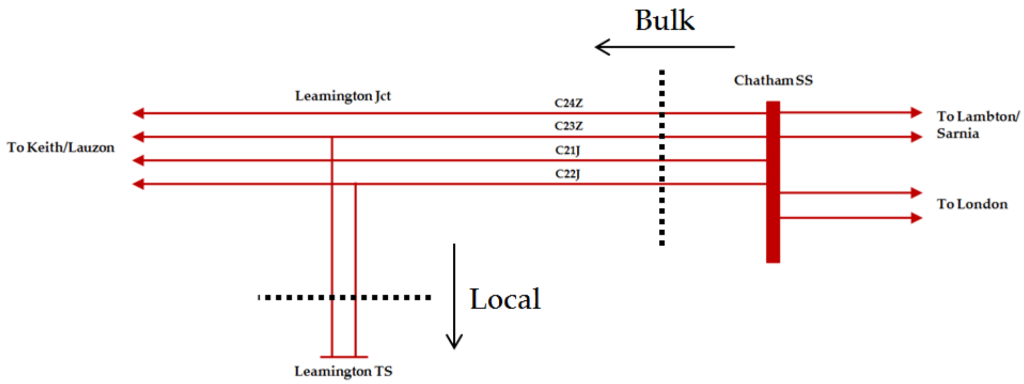
Station(s)	Description	Timing
Belle River TS	A potential supply capacity need was identified for the load served by Belle River TS	2028

6.2.1.6 Non-Wires Characterization

In contrast to the rest of the region where load forecast is relatively flat over the planning horizon, the Kingsville-Leamington area is experiencing sudden and unprecedented demand growth. In 2018 alone, Hydro One Distribution, the main distributor in the areas experiencing growth, received approximately 900 MW of new load requests with in Kingsville-Leamington– an amount comparable to the entire Windsor-Essex regional summer peak of approximately 960 MW in 2017. In light of this unique situation, the Working Group explored opportunities for demand-side options to maximize usage of existing infrastructure while concurrently developing transmission reinforcement options.

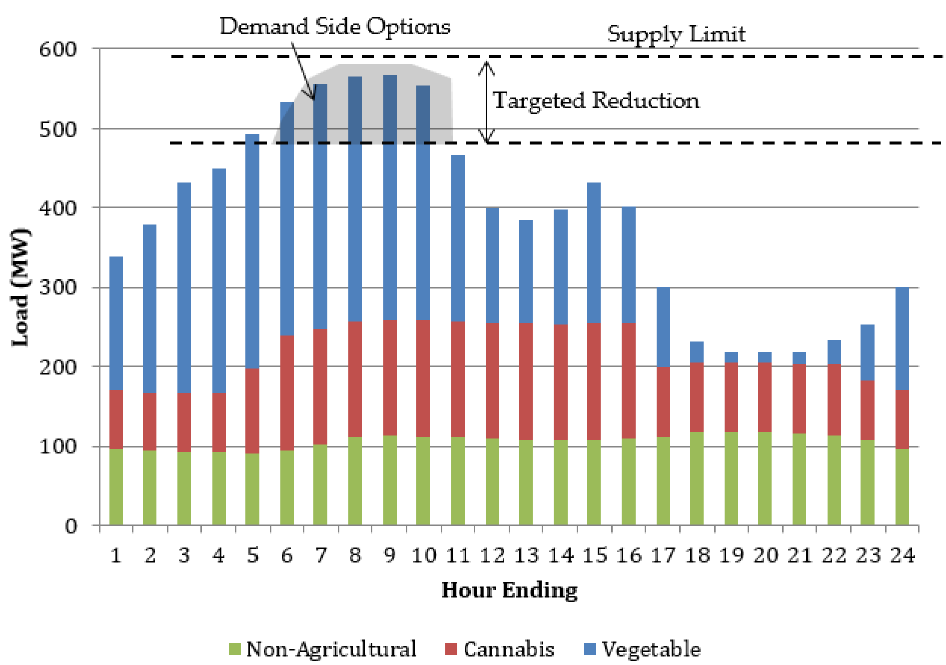
The system supply capability for the Kingsville-Leamington area is limited, as shown in Figure 6-1, by the lower of (1) the Leamington tap LMC and (2) upstream bulk transfer limits on the 230 kV circuits from Chatham SS. Demand-side options should be targeted differently depending which limitation is being addressed. To relieve Leamington tap LMC constraints, demand-side options must target the local Kingsville-Leamington peak as this is the only load downstream of the constraint. In contrast, the bulk circuits from Chatham SS serve more than just Kingsville-Leamington loads. To relieve bulk transfer limitations, demand-side options must target the portion of Kingsville-Leamington loads that is coincident with the overall bulk transfer interface peak. Since the Leamington tap LMC constraint is the most immediate limit, analysis of demand-side options in this IRRP focuses on reducing the Kingsville-Leamington local peak only. If the most limiting constraint changes in the future, further studies will be required to target demand-side options accordingly.

Figure 6-1: System Supply Capability for Kingsville-Leamington Area



The Kingsville-Leamington load profile is the summation of indoor agricultural load, cannabis loads and preexisting residential and commercial loads. The overall forecast winter load profile is shown in Figure 6-2.

Figure 6-2: Illustrative Kingsville-Leamington Area Winter Load Profile



The need in peak load hours that demand-side options seeks to address usually refers to the hours during which Kingsville-Leamington loads exceed the system's supply capability. In this context, where pent up demand already greatly exceeds the system supply capability, demand-side options can offer a way to manage existing agricultural and cannabis demand in hours approaching the supply capability limit by enabling more customers to connect, as illustrated in Figure 6-2. Given the magnitude of pent demand, demand-side options are not expected to replace or defer the need for infrastructure reinforcements, but rather maximize the utilization of existing assets.

The need is defined by three characteristics:

1. the magnitude (MW) over the supply limit or desired reduction in peak,
2. the duration (consecutive hours) that demand must be manage to achieve the desired magnitude of reductions, and
3. the frequency at which the need occurs per year or season.

The magnitude of the desired peak reduction will determine the duration and frequency of the need. The relationship between these variables is inherently probabilistic since the load profile varies daily and seasonally. As an example, Figure 6-3 visualizes the duration and frequency requirement for a desired peak reduction of 15 MW in 2021 using a heat map that shows the probability of a need arising in a given time of year and hour of day.

Figure 6-3: Heat Map Showing Need for 15 MW Reduction

% Probability of Demand Reduction Needed at the given MW Range or Greater

MW Range	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
14-15	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	1%
12-14	2%	3%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%
11-12	5%	6%	2%	0%	0%	0%	0%	0%	0%	0%	0%	2%
9-11	7%	12%	2%	0%	0%	0%	0%	0%	0%	0%	0%	2%
8-9	9%	14%	2%	0%	0%	0%	0%	0%	0%	0%	0%	4%
6-8	15%	22%	3%	0%	0%	0%	0%	0%	0%	0%	0%	5%
5-6	21%	26%	4%	0%	0%	0%	0%	0%	0%	0%	0%	8%
3-5	23%	32%	4%	0%	0%	0%	0%	0%	0%	0%	0%	9%
2-3	28%	36%	6%	0%	0%	0%	0%	0%	0%	0%	0%	14%
0-2	35%	40%	8%	0%	0%	0%	0%	0%	0%	0%	0%	17%
Month	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec

Key Statistics

Forecast Year	2021
Peak Reduction Targeted	15MW
Total Hours Requiring Demand Reduction per Year	95

% Probability of Demand Reduction Needed at the given MW Range or Greater

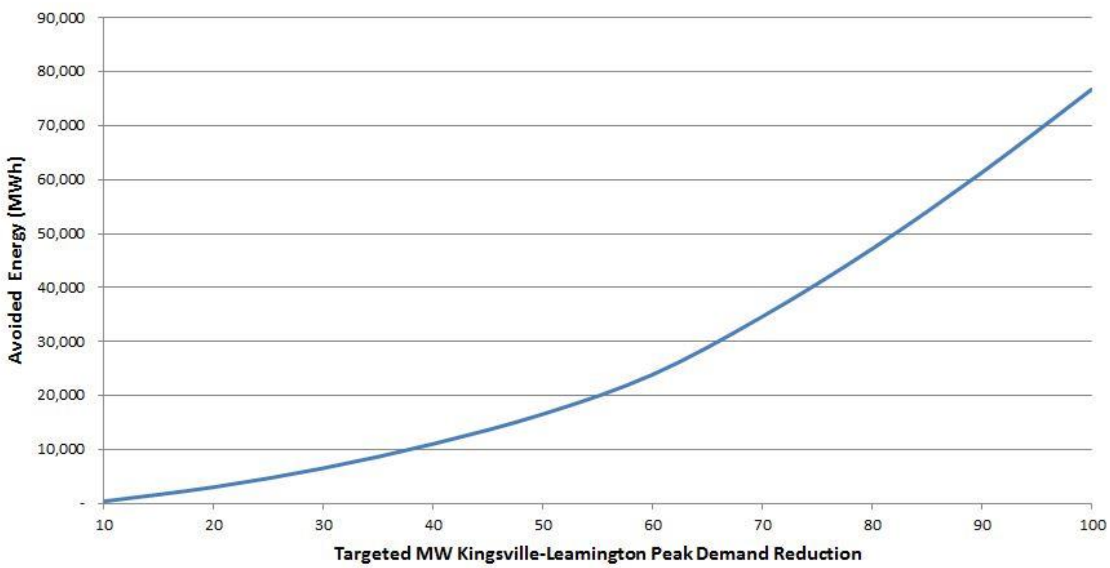
MW Range	1AM	2AM	3AM	4AM	5AM	6AM	7AM	8AM	9AM	10AM	11AM	12PM	1PM	2PM	3PM	4PM	5PM	6PM	7PM	8PM	9PM	10PM	11PM	12AM
14-15	0%	0%	0%	0%	0%	0%	0%	1%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
12-14	0%	0%	0%	0%	0%	0%	0%	2%	3%	1%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
11-12	0%	0%	0%	0%	0%	0%	0%	5%	6%	2%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
9-11	0%	0%	0%	0%	0%	0%	0%	8%	7%	4%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
8-9	0%	0%	0%	0%	0%	0%	0%	9%	12%	4%	4%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
6-8	0%	0%	0%	0%	0%	0%	0%	14%	19%	7%	4%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
5-6	0%	0%	0%	0%	0%	0%	0%	16%	23%	12%	8%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
3-5	0%	0%	0%	0%	0%	0%	0%	19%	25%	14%	8%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
2-3	0%	0%	0%	0%	0%	0%	1%	21%	33%	17%	11%	2%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
0-2	0%	0%	0%	0%	0%	0%	2%	26%	35%	19%	13%	2%	2%	1%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
Hour Ending	1AM	2AM	3AM	4AM	5AM	6AM	7AM	8AM	9AM	10AM	11AM	12PM	1PM	2PM	3PM	4PM	5PM	6PM	7PM	8PM	9PM	10PM	11PM	12AM

Each cell in the heat map shows the probability that, of the total hours requiring demand reductions, the hour or month shown on the x-axis will require the given magnitude range shown on the y-axis or greater. The heat map demonstrates that:

- A total of 95 hours in 2021 require some degree of demand reduction between 0 and 15 MW.
- These 95 hours are distributed in December, January, February, and March between the hours of 7 a.m. to 2 p.m.
- February mornings at 9 a.m. exhibit the greatest probability of requiring demand reductions. Over the year, it is statistically expected that approximately 35 of the 95 hours requiring demand reductions will occur at 9 a.m. Approximately 3 hours of the 35 will require a demand reduction in the 14 to 15 MW range.

The frequency and duration requirement increase non-linearly with the desired magnitude of peak reduction. Appendix C shows the heat maps for 2021 with 5 MW, 10 MW, 15 MW, 50 MW and 100 MW peak reductions. Figure 6-4 shows the relationship between the desired magnitude of peak reduction and the total avoided energy required. The relationship is roughly quadratic in the range between a 0 and 100 MW reduction in 2021.

Figure 6-4: Relationship Between the Avoided Energy and Peak Demand Reduction in the Kingsville-Leamington Area



6.2.2 Local Load Security and Reliability/Resilience

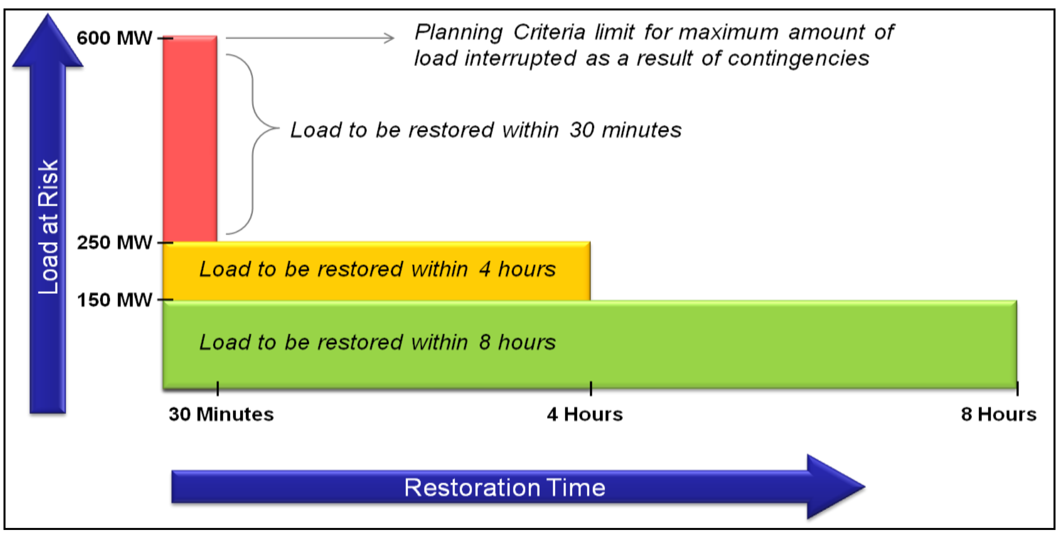
The transmission system must exhibit acceptable performance following specified design criteria contingencies. The load security criteria can be found in Section 7.1 of the ORTAC, and a summary of the load security criteria shown in Table 6-6.

Table 6-6: Load Security Criteria

Number of transmission elements out of service	Local generation outage?	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted by load curtailment, rejection, and curtailment
One	No	≤ 150 MW	None	≤ 150 MW
	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

ORTAC Section 7.2 further specifies that all interrupted load must be restored within approximately eight hours; interrupted load above 150 MW must be restored within four hours and interrupted load above 250 MW must be restored within 30 minutes. Figure 6-5 provides a visual representation of the load restoration criteria.

Figure 6-5: Load Restoration Criteria



Load security and restoration needs identified in the Windsor-Essex region for certain transmission outage conditions are described in Table 6-7.

Table 6-7: Windsor-Essex Region Load Security and Restoration Needs

Transmission Outage	Impacted Transformer Stations	Description	Timing
K6Z	Tilbury West DS	No need identified.	N/A
C23Z and C24Z	Lauzon TS	No need identified.	N/A
C21J and C22J	Leamington TS Malden TS	Interrupted load for the loss of both C21J and C22J exceeds load security and restoration criteria. Interrupted load for the loss of either C21J or C22J exceeds load security.	Today

6.2.2.1 K6Z (Tilbury)

When it reaches end of life in 2020, Tilbury TS will be decommissioned and load transferred to Tilbury West DS. The Scoping Assessment identified that analysis is required to determine whether additional reinforcements to the supply to Tilbury West DS are required to respect relevant planning criteria. The proposed system design satisfies ORTAC Section 7.2, for capacity, system restoration and load security. No further system reinforcements have been identified at this time.

6.2.2.2 C23Z/C24Z (Lauzon)

Subsequent to an outage of the C23Z and C24Z circuits, load supply to Lauzon TS is entirely interrupted. According to summer planning forecasts, this load is approximately 210 MW, of which 150 MW can be assumed restored within eight hours. As stipulated in ORTAC Section 7.2, the remaining 60 MW expected during peak hours at Lauzon TS must be restored within four hours.

Existing transmission reconfiguration options are sufficient to restore the interrupted load beyond 150 MW, as Lauzon TS can be resupplied through the 115 kV network and from the 230 kV/115 kV T1/T2 autotransformers. Through conversations with the transmitter and in consideration of typical circuit outage restoration timelines for the Windsor-Essex region, restoration of the remaining load under 150 MW is expected to occur within eight hours. As such, there are no additional load restoration requirements at Lauzon TS for the study period of this IRRP.

6.2.2.3 C21J/C22J (Leamington)

Subsequent to an outage of both C21J and C22J, approximately 510 MW of load on the Leamington tap will be interrupted by configuration. This includes 400 MW at the expanded Leamington TS and 110 MW at two transmission-connected customers all of which are expected to materialize before the in-service date of Lakeshore TS. In addition, approximately 140 MW of load will be interrupted by configuration at Malden TS. While the Malden TS load is not coincident with the winter peaking Leamington TS loads, the C21J/C22J double contingency outage will result in approximately 650 MW of load interrupted. This is in violation of ORTAC Section 7.1 for load security which only allows 600 MW of load interruption by configuration for two elements out of service. The existing transmission system also cannot meet the requirement (ORTAC Section 7.2) that load in excess of 250 MW to be restored within 30 minutes.

Subsequent to an outage on either C21J or C22J, one of the two transmission-connected customers on the Leamington tap will be interrupted by configuration resulting in a load loss of approximately 60 MW, which is within the acceptable amount of load allowed to be interrupted by configuration, as per ORTAC Section 7.1. An additional 120 MW at Leamington TS must also be rejected to bring the total load on the Leamington tap below its LMC of 370 MW. This is in violation of ORTAC Section 7.1, which does not allow any load to be interrupted by load rejection following a single element contingency.

In terms of load restoration for either a C21J or C22J outage, of the 180 MW of load interrupted; 30 MW must be restored within four hours and the remaining within eight hours. It can be reasonably assumed that the 30 MW can be transferred to Kingsville TS within four hours, while the rest can be restored within eight hours, in compliance with the restoration criteria stipulated by ORTAC Section 7.2.

6.2.3 End-of-life Asset Replacement Needs

The transmitter identified some end-of-life asset replacement needs for the Windsor-Essex region, with several needs arising in the near to medium term. These needs are summarized in Table 6-8.

Since end-of-life needs are based on the best available asset condition information at the time of each stage of the planning cycle, timing of asset needs can change as new information becomes available. As a result, the scope and timing of some asset needs has been revised since the Needs Assessment and Scoping Assessment were completed.

Table 6-8: Windsor-Essex Region End-of-life Asset Replacement Needs

Facilities	Need	Expected Timing
Lauzon TS	▪ End-of-life step-down transformers T6 and T8	2024
	▪ End-of-life step-down transformers T5 and T7 ▪ End-of-life autotransformers T1/T2	2029
Keith TS	▪ End-of-life 230/115 kV autotransformers T11/T12	2024
	▪ End-of-life 115 kV/27.6 kV transformer T1	2024

6.2.3.1 Lauzon Transformers

Lauzon TS currently consists of two 230 kV/115 kV autotransformers (T1/T2) and four step-down transformers: T5 and T6 (which supply DESN 1), and T7 and T8 (which supply DESN 2).

Both DESN stations are supplied at 230 kV and both supply two low-voltage switchgears at a distribution voltage of 27.6 kV.

During the Needs Assessment, Hydro One identified that the T1 and T2 autotransformers and the T6 and T7 step-down transformers would be reaching their end of life within the next 10 years. During the development of the IRRP, Hydro One refined its original estimate, finding that the T6 and T8 step-down transformers will be reaching their end of life by 2024, while the remaining transformers (T1, T2, T5 and T7) have potential end-of-life needs within the next decade. Given that these transformers have been in service for between 40-49 years, they will all require replacement for safety, reliability, and maintainability purposes shortly.

Lauzon TS currently supplies 220 MW of load in the summer. With a planning forecast year-over-year growth rate between -1.2% and +0.3%, the load at the Lauzon TS is expected to remain fairly flat. However, DESN 1 currently supplies 40 MW more than DESN 2, about 130 MW and 90 MW respectively. Consequently, there is also a current and continuing transformer capacity need at DESN 1, whose current rating is 112 MVA or approximately 100 MW.

The total load connected on the Windsor-Essex region 115 kV system is supplied by both the Lauzon TS autotransformers and the Keith T11/T12 autotransformers. This load is also projected to be relatively flat over the study period, with a yearly growth rate ranging from -1.5% to +0.7%. There is currently no foreseeable need to uprate the Lauzon autotransformers.

6.2.3.2 Keith Transformers

Keith TS is currently composed of:

- Two 230 kV/115 kV autotransformers T11 and T12,
- One DESN supplied by two 230 kV/27.6 kV transformers T22/T23, and
- One DESN supplied by one 115 kV/27.6 kV transformer T1.

During regional coincident peak demand, approximately 60 MW of total load is currently served by Keith TS in the summer, with about 90 MW served during non-coincident peak times.

ENWIN, Hydro One Distribution, and EPL (as an embedded customer) constitute this load, which exhibits a yearly growth rate of less than 1% throughout the study horizon.

Decommissioning of the end-of-life T1, which historically supplied approximately 7 MW during times of regional coincident peak demand, directly impacts ENWIN load. This industrial customer is shifting its operations; as such, by 2020 the corresponding load will no longer be connected to Keith TS, so there is no additional capacity need.

Keith TS T11/T12 autotransformers currently connect the Windsor-Essex 230 kV network with the 115 kV network. The 2015 IRRP did not identify additional capacity requirements through T11/T12, but recognized the need for a like-for-like replacement of these autotransformers. However, subsequent discussions between Hydro One and IESO confirmed that the incremental cost to upgrade the units from 115 MVA to 250 MVA would be justified. This upsizing is supported through studies preceding the IRRP, which assessed scenarios varying local generation and loads under CxZ circuit outages and the impact on power flow through T11/T12. Considering the exceedance of transformer capacity under some of these scenarios before an upsizing occurs, this IRRP is in agreement with the Needs Assessment and Scoping Assessment regarding the Keith T11/T12 autotransformer findings and recommendations. No further needs have been identified for the Keith transformers.

6.3 NEEDS SUMMARY

The majority of needs in the Windsor-Essex region focus on addressing the growing station capacity shortfalls which exist today and into the long term, to ensure adequate load restoration, and some replacement of assets when they reach their end of life.

Table 6-9 provides a brief summary of needs considered during the development of options for the plan in chronological order of need date.

Table 6-9: Summary of Needs in Windsor-Essex Sub-Region

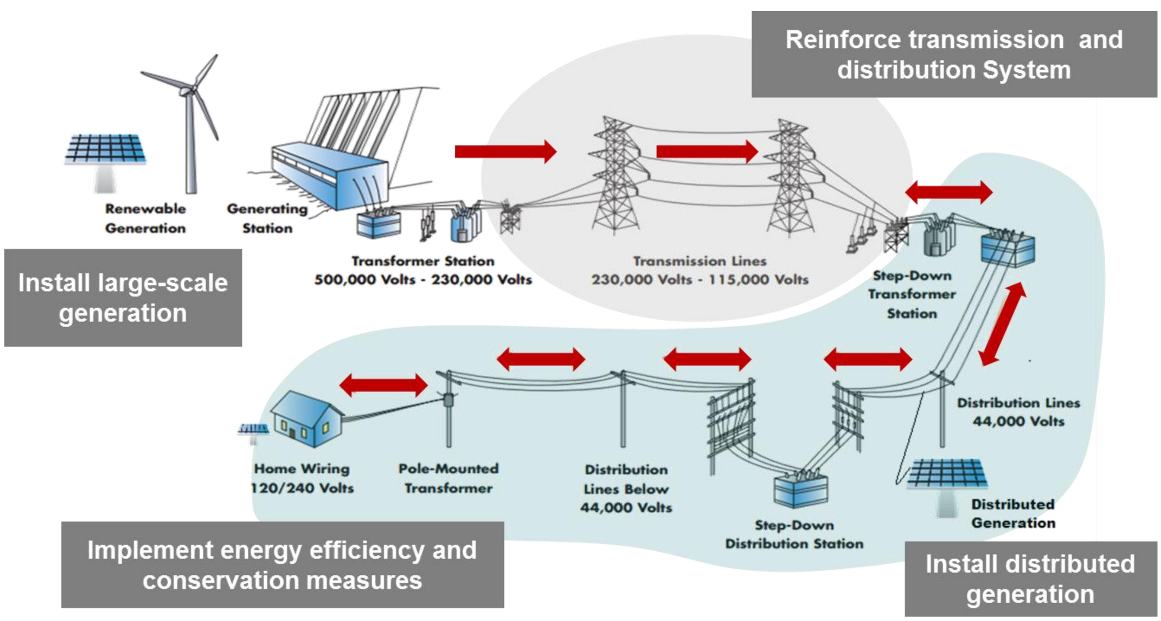
Area	Need	Description	Need Date
Kingsville TS	Supply Capacity	A supply capacity need was identified for the load served by Kingsville TS.	Today
Kingsville-Leamington Sub-system	Supply Capacity	A supply capacity need was identified for the load cumulatively supplied by the 115 kV circuits extending radially from the Lauzon sub-system and the radial Leamington tap connected to the upstream C21J/C22J 230 kV circuits.	Today
Leamington (C21J/C22J)	Load Security and Restoration	Interrupted load for the loss of both C21J and C22J exceeds load security and restoration criteria. Interrupted load for the loss of either C21J or C22J exceeds load security.	Today
Lauzon DESN 1	Station Capacity	A station capacity need was identified for the load supplied by the T5/T6 DESN 1 at Lauzon TS.	Today
Lauzon TS (DESN 1 and 2)	Station Capacity	An existing station capacity need was identified for the total load supplied by Lauzon TS	Today
Kent TS	Station Capacity	A supply capacity need was identified for the load served by Kent TS.	2020
Lauzon 115 kV Sub-system	Supply Capacity	A supply capacity need was identified for the load cumulatively served by Kingsville TS, Belle River TS, and Tilbury West DS.	2023
Lauzon TS Transformers	End of Life	Hydro One has identified the step-down transformers (T6 and T8) to be at end of life.	2024

Area	Need	Description	Need Date
Belle River TS	Station Capacity	A transformer capacity need was identified for the load supplied by T1/T2 at Belle River TS.	2028
Lauzon TS Transformers	End of Life	Hydro One has identified the autotransformers (T1/T2) and step-down transformers (T5 and T7) to be nearing end of life.	2029

7. Options and Recommended Plan to Address Regional Electricity Needs

As shown in Figure 7-1, power has traditionally been generated from large, centralized generation sources. To provide electricity supply to the various communities across Ontario, power has been delivered through transmission and distribution infrastructure. To address regional and local electricity needs one approach is, therefore, to reinforce the transmission and distribution infrastructure supplying the local area. In recent years, however, communities and customers have been exploring opportunities to reduce their reliance on the provincial electricity system by meeting their electricity needs with local, distributed energy resources and community-based solutions. This approach includes a combination of emerging technologies and energy-efficiency programs, such as targeted DR and energy-efficiency programs, DG and advanced storage technologies, micro-grid and smart-grid technologies, and more efficient and integrated process systems combining heat and power.

Figure 7-1: Options to Address Electricity Needs



Options Evaluation

When evaluating alternatives, the Working Group considered a number of factors, including technical feasibility, cost, flexibility, alignment with planning policies and priorities and consistency with long-term needs and options. Solutions that maximized the use of existing infrastructure were given priority.

Investing in new electricity infrastructure, such as a new transmission line or a generation facility requires substantial capital investment, has environmental/land-use impacts and has a long service life. As such, it is important to take into the consideration the longer-term cost implications, value and potential risks (e.g., stranded or underutilized assets) when recommending an investment. Furthermore, these facilities typically require long lead times to obtain approvals and complete construction. Decisions on new facilities must take into account these considerations and be made with sufficient lead time to ensure they are available when needed.

When assessing the need for infrastructure investments, it is important to strike a balance between overbuilding infrastructure (e.g., committing to infrastructure when there is insufficient demand to justify the investment) and under-investing (e.g., avoiding or deferring investment despite insufficient infrastructure to support growth in the region). Typically, demand management and energy-efficiency programs can be implemented within six months, or up to two years for larger projects, whereas transmission and distribution facilities can take five to seven years to come into service. The lead time for generation development is typically two to three years, but could be longer depending on the size and technology type.

Finally, the issue of how much is appropriate to invest and who pays needs to be addressed. In regional planning, depending on the type and classification of assets, the costs may be shared by all provincial ratepayers or recovered only by the specific customers they serve (e.g., LDC, industrial customers). In some cases, a combination of cost-sharing may occur when there are both provincial and local benefits.

Near-Term Actions and Long-Term Planning Considerations

For the near and medium term, the IRRP identifies specific actions and investments for immediate implementation. This ensures that necessary resources will be in-service in time to address more pressing needs. For the long term, the IRRP identifies potential options to meet needs that may arise in 10 to 20 years. It is not necessary to recommend specific projects at this time (nor would it be prudent given forecast uncertainty and the potential for technological change). Instead, the long-term plan focuses on developing and maintaining the viability of long-term options, engaging with communities, and gathering information to lay the groundwork for making decisions on future options.

As discussed in Section 5.7.2, actions need to be taken to address (1) local transformer station and supply capacity needs, (2) local load security and restoration needs, and (3) asset replacement needs. Given the significant and diverse capacity needs identified, this is further broken down into three areas: (1) the Kingsville-Leamington area, (2) 115 kV sub-systems, and (3) other local capacity needs. In developing the 20-year plan, the Working Group examined a wide range of integrated solutions to address local and regional needs and recommended additional studies that to inform mid- and long-term plans and actions. These options are discussed in the following section.

7.1 OPTIONS FOR ADDRESSING KINGSVILLE-LEAMINGTON AREA CAPACITY NEEDS

In contrast to the rest of the region where load forecast is relatively flat over the planning horizon, the Kingsville-Leamington area is experiencing sudden and unprecedented demand growth, comparable to the entire Windsor-Essex regional summer peak. Capacity needs in the Kingsville-Leamington area are currently being addressed through interim measures, which results in a lower level of reliability. Various options to address this, along with the rapid load growth forecast for the area were considered, including non-wires options and other wires solutions as described in this sub-section.

7.1.1 Non-Wires Options

In light of the unique load profile in this area, the Working Group explored opportunities for demand-side options to maximize usage of existing infrastructure while concurrently developing transmission reinforcement options.

Demand-side options can be categorized as dispatchable or non-dispatchable solutions. Dispatchable solutions are measures that actively reduce the demand in response to dispatch signals targeting the specific hours when the need occurs. Non-dispatchable solutions are measures that broadly reduce electricity consumption to address the need without requiring active management. This section documents LAC discussions on two options:

(1) Dispatchable – Lighting load demand response, and
(2) Non-dispatchable – Lighting technology energy efficiency.

Lighting Load Demand Response

Demand response is a dispatchable solution involving loads that can be reduced or avoided during hours when the need occurs. Since lighting comprises the vast majority of load in agricultural and cannabis facilities, DR targeting lighting schedules would have the most impact on peak reductions. This can be accomplished through either lighting load curtailment or local behind-the-meter generation and storage.

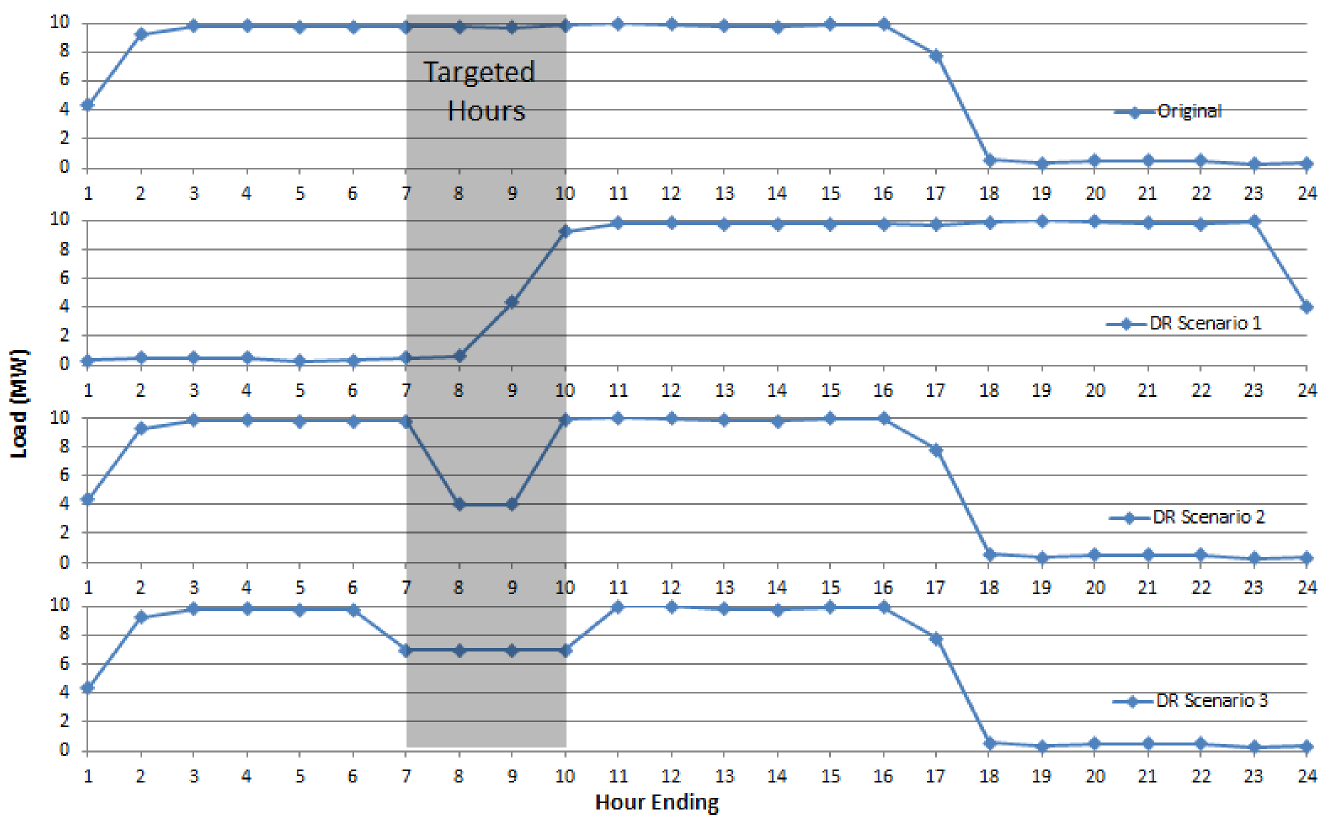
The existing provincial DR auction, as detailed in the IESO's Market Manual 12, typically consists of procuring DR resources zonally with a $/MW-day clearing price for summer or winter commitment periods. Successful DR resources are then required to participate in the energy market during all availability windows with a bid ($/MWh) greater than a DR bid price threshold. The LAC identified three broad barriers that prevent the direct application of the provincial DR program in relieving the Leamington tap LMC constraint:

- The provincial DR program specifications are designed to address the provincial seasonal peak which typically occurs on summer afternoons and winter evenings and do not align with the local Kingsville-Leamington peak,

- Zonal procurement is not granular enough to target the select stations downstream of the Leamington tap LMC constraint, and
- The requirement to participate in the energy market may not accommodate artificial horticulture lighting constraints such as maximum seasonal frequency and duration of curtailment.

The last barrier, the accommodation of horticulture lighting constraints, may be the most challenging to address due to the lack of industry knowledge and comfort around quantifying the specific agricultural and cannabis constraints. The LAC explored possible variations of lighting DR, examples of which are illustrated in Figure 7-2, but no consensus was reached on which variations were acceptable to local growers and facility operators.

Figure 7-2: Illustrative Lighting Demand Response Scenarios



In DR Scenario 1, the entire lighting period shifted by eight hours; DR Scenario 2, depicts a large magnitude, short duration lighting load reduction; and DR Scenario 3 shows a low-magnitude, long duration lighting load reduction.

While there are broad indications that short, infrequent lighting curtailment may be acceptable, there remain a number of questions which remain unanswered due to the lack of industry experience with DR including:

- What specific actions can be taken or technologies employed to reduce load during the hours when need arises?
- What operational or economic barriers exist for behind-the-meter generation or storage?
- What is the cost associated with taking DR actions including the impacts on crop productivity?
- What are the maximum duration and frequency of lighting curtailment in a growing season?
- What procurement constraints such as commitment period, forward period and activation lead time exist and how would they impact participation?
- Are there variations between crop types that would impact the answers to any of the above questions?

<u>Lighting Technology Energy Efficiency</u>

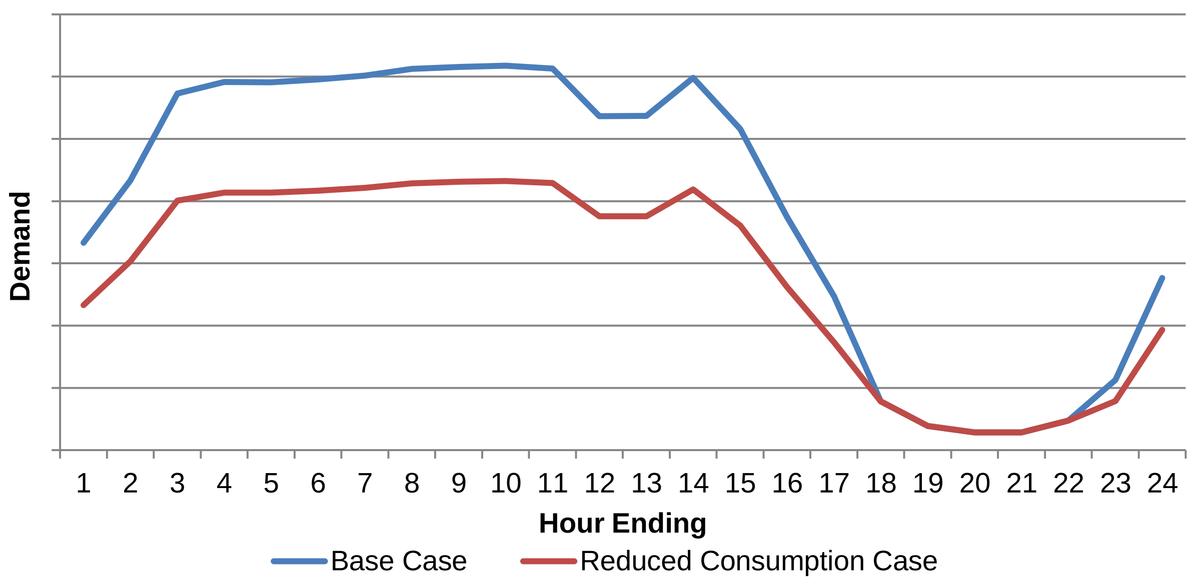
As with demand-response solutions, since the overwhelming majority of the demand growth is driven by lighting loads, discussions of energy-efficiency measures have been focused on lighting technologies. Energy-efficiency measures are non-dispatchable solutions that help address the need by reducing the overall energy and demand consumption, but do not require signals or instructions to activate.

The primary artificial lighting technology used in agricultural applications is the HPS lamp with an energy intensity of approximately 1 kW lamp per square meter. The LAC confirmed that LED horticulture lighting technology offers approximately 20-40%[14] improved energy efficiency

[14] Anticipated efficiency improvement varies widely depending on light spectrum requirements and layout design.

but with a four to five fold increase in capital cost compared with HPS lamps. LED lighting minimizes waste heat which enables higher density vertical farming but may be disadvantageous in winter operations when heating is required. Figure 7-3 visualizes the anticipated load profile impact of LED lighting at a generic agricultural facility. Note that the improved efficiency impacts all hours with the exception of 6 p.m. to 10 p.m. when no lighting is anticipated. This impact profile makes lighting energy-efficiency well suited to address local capacity constraints.

Figure 7-3: Sample Agricultural Load - Winter Day Profile



The LAC clearly indicated that the primary barrier to date for LED proliferation is technology maturity risk. The LED horticulture lighting industry is still in a high degree of flux. The rate of change in LED technology means subsequent product iteration in the near future will likely outperform any LED lighting investments made today at lower cost. The LAC raised concerns about warranty dependability due to high turnover in suppliers coupled with performance reliability issues significantly hinders LED technology investments. The LAC also expressed concerns regarding the impact of LED lighting on crop productivity and the difficulty in testing LED products that lack industry standards and are prone to rapid iterative changes.

Despite concerns raised by the LAC, there are indications that the horticultural lighting industry is evolving to address the need for standardization, which may improve current and future LED products. In late 2018, the American Society of Agricultural and Biological Engineers (ASABE) published new lighting standards that enables standardized product testing and facilitates comparison of products between manufacturers. The DesignLights Consortium (DLC) is also updating their testing and technical requirements for products to be qualified in a new DLC Horticultural Lighting Qualified Products List.

Currently under the Interim Framework, and previously the Conservation First Framework, there is a retrofit program to incentivize adoption of LED lighting for existing facilities. Since this change was recently implemented, it is too early to determine the impact on the uptake of LED technology with agricultural loads. Previously, there was also a High Performance New Construction program under which incentives were available for new indoor agriculture facilities. With the cancellation of that program in April 2019, the ability to incent the installation of LEDs is reduced, but is still applicable for new installations under the Retrofit Program.

7.1.1.1 Targeted Call for Innovative Projects

Given the barriers to demand-side options identified above and the gaps in industry knowledge regarding the feasibility of these options with the unique end use applications driving load growth in Kingsville-Leamington, further work is recommended to explore the potential of demand-side options with agricultural loads.

The IESO will consider a targeted call for innovative projects under the Grid Innovation Fund in Q1 2020. The GIF advances innovative opportunities to achieve electricity bill savings for Ontario ratepayers by funding projects that enable customers to better manage their energy consumption or that reduce the costs associated with maintaining reliable operation of the province's grid. The IESO will leverage LAC discussions and the work already performed to date for demand-side options in Kingsville-Leamington to help scope parameters of the targeted call. The call will solicit projects related to indoor agriculture that validates the performance and business case of promising new technologies, practices, and services. Since other areas of the province such as Dresden and Niagara are experiencing similar agricultural sector growth, the call will open to projects across the province.

7.1.1.2 Provincial Energy-Efficiency Programs

While concerns such as technology maturity, reliability, and crop performance will likely limit uptake of LED horticulture lighting technology with additional programs or incentives, the IESO will evaluate existing and any future energy-efficiency programs beyond the Interim Framework to increase participation in areas with identified local need. There is an opportunity for energy-efficiency programs to influence the technologies used while the indoor agriculture and cannabis industries rapidly expand. Given the magnitude of growth forecast in Kingsville-Leamington, there remains a need to manage the growth in the long term even after the implementation of the wires reinforcements in Section 7.1.3. The IESO will notify relevant communities of any future energy-efficiency opportunities that may arise.

7.1.1.3 Continued Monitoring of Industry Developments

The IESO will continue monitoring the status of indoor agriculture industry developments through the ongoing Greenhouse Energy Profile Study. This study forecasts energy use for the greenhouse sector over the next five to 10 years and quantifies the potential for energy and water savings, and is anticipated to conclude in Q3 of 2019.

7.1.2 Local Generation

While there are off-grid generation assets owned and operated by customers in the Kingsville-Leamington area, the need for grid-supplied capacity persists. Customer owned generation assets such as CHP facilities are generally sized to fulfill thermal or CO_2 requirements. Facilities of this size may be sufficient to meet baseload electricity requirements but are not suited to supply highly energy-intensive lighting demand. Meeting the entire electricity requirements of lighting loads with behind-the-meter generation would entail either the installation of dedicated electricity generation assets such as a simple-cycle gas turbine or drastically oversizing CHP facilities. These strategies are typically cost-prohibitive compared to grid supply unless there are additional revenue streams aside customer load supply.

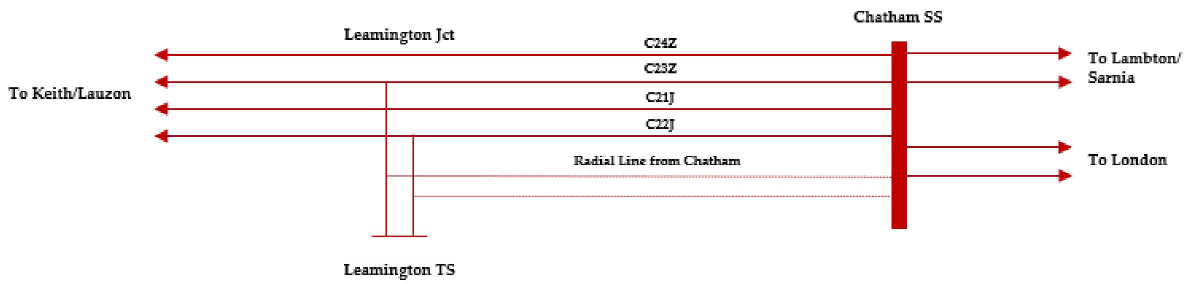
Grid-connected behind-the-meter generation assets are also an option, but existing facilities are expected to take up the bulk of the remaining short circuit limitation at the expanded Leamington TS, with some room remaining at Kingsville TS. The IESO, with the Working Group, will monitor the growth of local generation in the Kingsville-Leamington area. This information will be used to update the forecast net demand which may impact the timing of future transmission and distribution infrastructure plans and inform the next cycle of regional planning for the area.

7.1.3 Leamington Switching Station (Lakeshore TS)

Due to the magnitude and timing of the requirement, non-wires options alone are not sufficient to meet the identified needs. A grid-supplied generation option located at Leamington Junction was considered but was impractical due to the technical infeasibility and high anticipated cost. A new generator would need to be connected close to the load centre, near Leamington Junction, and a 230 kV bus would be required to accommodate the size of that facility. This bus would essentially be the equivalent of a 230 kV switching station, which negates the value of generation, since this option would provide the same benefits described later for the switching station, but with the additional cost of building generation.

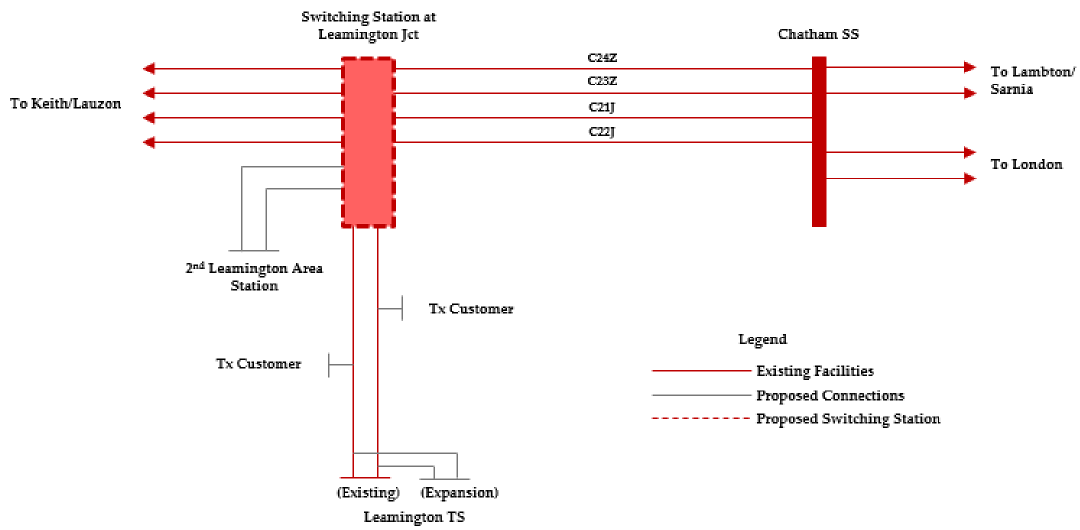
An option to build a new radial 230 kV line from Chatham SS to Leamington TS, as shown in Figure 7-4, was also considered. The LMC would be insufficient to meet the forecasted growth, since it would be limited by voltage concerns as is typical of a radial line connected to a large load. In addition, the solution would not provide the flexibility to supply future growth beyond the Leamington TS expansion.

Figure 7-4: Configuration of Option for a Radial line from Chatham



Another option is a switching station at or near the Leamington Junction, north of the municipality of Leamington, which would sectionalize and switch the four existing 230 kV circuits going west from Chatham SS to the Windsor area (C21J/C22J/C23Z/C24Z). This option is shown in Figure 7-5. The switching station would improve reliability, and provide some additional local supply capability to connect an additional transformer station and continue supplying load in the Kingsville-Leamington area. See Appendix C.9.2 for details. Upstream transmission limitations are still anticipated but can potentially be mitigated by interim congestion management strategies.

Figure 7-5: Configuration of Option for a Switching Station at Leamington



In addition to improving load supply capability in the Kingsville-Leamington area, the proposed switching station will improve the performance of the bulk system by balancing the flow on the existing transmission circuits from Chatham, thus enhancing transfer capability. The switching station will also reduce exposure to outages by allowing the existing 230 kV circuits to be sectionalized and switched independently, as outlined in Section 7.4. Furthermore, it will allow for future transmission reinforcements to increase the transfer capability west of Chatham which will maintain existing export capability to Michigan while enabling additional load growth throughout the Windsor-Essex region.

7.1.4 Interim Measures

The Windsor-Essex region already has a number of interim measures in place. These include existing special protection systems – originally designed to address automotive industry loads – to help improve reliability to the region. These SPSs are still used today in some scenarios, such as under high import or export conditions.

Load in the Kingsville-Leamington area has also historically exceeded the capability of existing local transmission infrastructure. Summer-peaking load at Kingsville TS has ranged from 120 to 130 MW, and SPSs have been used to accommodate this demand by interrupting load in the Kingsville area following recognized contingencies. While this enabled higher load connection than the Kingsville TS capability, local customers experience reduced reliability compared to that provided in the rest of the province.

Load growth in the area will increase the frequency of the SPS use mentioned above and require new interim protection measures for customers connecting prior to the in-service date of the switching station and new line from Chatham SS to the switching station (outlined in the bulk Windsor-Essex report). The interim measures address both thermal and voltage limitations for a range of recognized contingencies to allow loads to connect on the Leamington tap above its current load meeting capability. Interim measures include both contingency- and voltage-based SPSs enabling load and capacitor rejection at Leamington TS.[15]

7.1.5 Continued Monitoring of Kingsville-Leamington Load Growth

Given the rapid growth and changing nature of load in the Kingsville-Leamington area, changes to the assumptions for demand in this region could significantly impact the suitability of the recommended plan. To mitigate this, on an annual basis, the IESO, with the Working Group, will review actual load growth in the Kingsville-Leamington area, the queue of load customers requesting connection from LDCs, transmitter or the IESO, and factors driving growth of the sector. This information will be used to determine when decisions on the long-term plan are required, inform the next cycle of regional planning for the area, and trigger a cycle early, as required.

7.2 OPTIONS FOR ADDRESSING THE 115 KV SUB-SYSTEM CAPACITY NEEDS

In addition to a supply capacity need in the Lauzon 115 kV sub-system starting in 2023, multiple present-day capacity needs in the current nested 115 kV sub-systems have been identified. These include a station capacity need at Kingsville TS, transformer capacity need at Lauzon DESN 1, and station capacity need at Lauzon TS (DESNs 1 and 2). Currently, existing capacity needs are being managed with SPSs.

In light of these supply requirements, the IRRP considered the option of converting Kingsville TS from its 115 kV supply to 230 kV, non-wires options, and supply from Keith TS. These options have many implications, requiring an integrated and coordinated evaluation that prevents recommendations for numerous needs from occurring in isolation. Conversion of Kingsville to 230 kV would effectively solve the Kingsville station capacity need, as well as remove it entirely from the Lauzon 115 sub-system, eliminating the sub-system’s supply capacity need. Depending on which 230 kV circuits ultimately supply the reconfigured

[15] Interim measures will be specified in detail in the Leamington TS expansion SIA.

Kingsville TS, the conversion could also relieve the voltage violations that characterize the Lauzon station capacity need.

There are two options for staging this conversion, considering the ongoing transmission developments in the area:

Option One: Build Lakeshore DESN 1, convert Kingsville from its 115 kV supply to 230 kV, and then build Lakeshore DESN 2. This would allow for an equitable load connection sequence based on the chronological order of customer requests. While there is load growth near both the proposed Lakeshore TS and existing Kingsville TS, customers earlier in the connection queue are geographically closer to the Kingsville station. However, Kingsville TS is currently fully utilized, with interim measures being used to supply existing customers beyond the capability of the station. In Option One, therefore, the initial DESN station at Lakeshore would first supply new loads in its proximity, followed by the 230 kV Kingsville conversion to supply loads closer to Kingsville and relieve the interim measures at Kingsville TS. The second Lakeshore DESN would subsequently enable remaining customer connections in the area.

Option Two: Build Lakeshore DESN 1 and DESN 2 before converting Kingsville to 230 kV. This would better align with Hydro One's preliminary implementation plan, which includes timelines for design, construction, and environmental assessments (EAs). Hydro One has already begun the EA for the two Lakeshore DESNs, with construction scheduled for early 2020 and an expected in-service date of 2023. The conversion of Kingsville from 115 kV to 230 kV would also require its own EA, Section 92, and construction of transmission infrastructure to the existing 230 kV system, which would take five to seven years.

Based on these timelines, Option Two would connect more customers in a shorter timeframe than Option One. However, if adhering to the chronological order of the customer connection application queue, new customers near Kingsville TS would be supplied from the more electrically-distant Lakeshore TS with long distribution feeders, resulting in approximately $20-million in additional distribution costs. One benefit of this option, though, would be the potential for load restoration capability between Kingsville and Lakeshore stations under the final distribution network configuration. Option Two would also allow the IESO additional time to assess the firmness of load growth in the area, given that it is largely driven by a single sector. Moreover, until upstream bulk transmission reinforcements are in-service (specifically the new 230 kV circuit from Chatham to Lakeshore), any additional supply capability resulting from the 230 kV conversion of Kingsville TS cannot be fully utilized.

As the load in the Kingsville-Leamington area continues to materialize and stations are constructed to provide local supply, converting Kingsville to 230 kV could also provide the long-term flexibility to address Leamington load security and restoration needs after the switching station is in-service, as identified in Section 7.4. Final distribution system build-out between Kingsville and Lakeshore in Option Two would also be a factor to consider in this regard.

Beyond the ability to address multiple capacity needs, this study would inform the end-of-life needs at Lauzon TS. As explained in Section 7.5.1, end-of-life transformers T5/T6 at Lauzon TS could be addressed through an upsizing rather than a more straightforward like-for-like replacement. However, the justification for increased transformer capacity of T7/T8 and step-down transformer capacity of T1/T2 must align with the ability to first relieve Lauzon station capacity needs – which, in turn, must align with the potential 115 kV sub-system capacity and Leamington restoration study.

Ultimately, optimizing the configuration of Kingsville to address the multiple needs identified requires careful consideration, at a minimum, of which of the existing 230 kV transmission lines (C21J/C22J/C23Z/C24Z) to connect to, whether to move the station from 115 kV to 230 kV or maintain a 230/115 kV connection, and reactive requirements. Given the study work that is required to be completed and the implementation timelines of Hydro One, the Working Group recommends that the 115 kV sub-system capacity and Leamington restoration needs be examined in detailed through IESO-led studies undertaken subsequent to this IRRP, and expected to be completed by Q2 of 2020. A plan for the proposed work is provided in Appendix C.

7.3 OPTIONS FOR ADDRESSING LOCAL SUPPLY CAPACITY NEEDS

7.3.1 New DESN Station in Chatham-Kent

Four options were considered to supply the capacity need at Kent TS:

1. Upsize the existing T3/T4 DESN transformers at Kent TS from 25/42 MVA single winding transformers to 50/83 MVA dual winding transformers,
2. Add two additional 230/27.6 kV DESN transformers at Kent TS,
3. Build a new DESN station west of Kent TS connecting to the idle Section K6Z, and
4. Build a new DESN station south of Chatham proper connecting to the 230 kV circuits between Chatham and Keith/Lauzon

With the existing Kent TS fully loaded by 2020, and without the ability to transfer load, supply could not be maintained during outages to the existing transformers required for the replacement. In addition, the new capacity need is located south of Chatham, requiring long feeders from Kent to the load, which would add significant distribution costs. Existing station egress and feeder routing challenges have also been identified through the feeder work required to utilize the remaining capacity at Kent TS to supply part of this new load.

Option Two would add two additional 230/27.6 kV DESN transformers to Kent TS, with a capacity of 150 MW. This option could be implemented in two to three years, which would address the short-term need and future load growth in the Chatham-Kent area, but not resolve the distribution, egress, and feeder routing challenges as identified above.

The option to site a new DESN station west of Kent TS, connecting to the idle Section K6Z was ruled out for timing and economic reasons. Since the existing easement is too crowded to add more feeders, the approximately 4.5 km of idle K6Z would need to be rebuilt to a double 230 kV circuit from Kent TS to the new site and would require an EA and Section 92, increasing both implementation timelines and project costs. In addition, this option is not supported by the Municipality of Chatham-Kent due to concerns regarding construction through residential areas.

The option to site a new DESN station south of Chatham proper, is preferred due to comparable or lower costs and potential for load transfer capability between the proposed site and existing loads that are in closer proximity but currently being fed from Kent TS. Implementation times for this option may be slightly longer since an EA may be required, but given the proximity to existing 230 kV circuits, connection will not require a Section 92. If this station is constructed prior to the proposed switching station at Leamington Junction, connection to the CxJs would be restricted given the amount of load already supplied through these circuits. After the switching station, the limiting factor would be potential supply issues east of Chatham. To mitigate the capacity need at Kent TS, the Working Group recommends that a new DESN station be built south of Chatham proper.

7.3.2 Continued Monitoring at Belle River TS

While Belle River TS is forecast to experience moderate load growth over the study period, its transformer capacity need (as described in Section 6.2.1.5) does not arise until 2028.

The implementation of provincial energy-efficiency initiatives will continue to offer benefits into the mid to long term for the Windsor-Essex region. In developing the demand forecast, peak-demand impacts associated with meeting provincial targets through the Interim Framework were assumed before identifying residual needs, consistent with the approach taken in all IRRPs. Meeting provincial energy-efficiency targets will address approximately 22% of the total forecast demand growth by the end of the study period. Implementation of the existing target will help to address the future capacity need at Belle River TS and maintain load levels below the available station capacity into the mid and long term based on the forecast.

Absent of provincial targets, or if the forecast load were to increase for this station, the Working Group should reevaluate the capacity need. In accordance with its recommendation, the Working Group and the IESO will monitor Belle River TS load, before making a final determination on whether to proceed with options to increase station capacity in the next planning cycle.

7.3.3 Continued Monitoring of Regional and Bulk Transmission Projects

The implementation of a number of transmission projects underway in the Windsor-Essex region, will significantly impact the ability to meet the capacity needs identified in this IRRP.

On the bulk system, the new transmission line from Chatham SS to Lakeshore TS is targeted to be in-service by the winter of 2025/2026. While this line was primarily designed to increase the overall transfer capability of the bulk transmission system west of Chatham, it supports the reliably supply of the forecast load growth in the Kingsville-Leamington area.

On the regional system, the new switching station (Lakeshore TS), various DESN stations at Leamington TS and Lakeshore TS, and transmission-connected customers are scheduled for the near to medium term. The implementation of these projects will directly affect the rate of load growth in the region and the feasibility of proposed mid-term options.

To ensure that regional and bulk plans adequately meet projected near- and mid-term needs, the IRRP recommends that the IESO, with the Working Group, monitor and report the status of Windsor-Essex transmission projects between regional planning cycles on an annual basis. This information will be used to determine when decisions on the long-term plan are required, and to inform the next cycle of regional planning for the area.

7.4 OPTIONS FOR ADDRESSING LOCAL SECURITY AND LOAD RESTORATION NEEDS

Of the three load security and restoration needs evaluated in Section 6.2.2, only the C21J/C22J outage need at Leamington persists and cannot be met by the existing transmission system.

The switching station, as specified in Section 7.1.3, alleviates some but not all load security and restoration needs. Prior to the switching station, an outage on both C21J and C22J would result in the loss of all load on the Leamington tap as well as Malden TS. The switching station sectionalizes the C21J/C22J/C23Z/C24Z circuits into two sections east and west of the switching station. A double contingency on C21J/C22J west of the switching station only results in the loss of Malden TS which is below 150 MW and can be restored within the mandatory eight-hour time limit. Contingencies on any of the four existing circuits east of the switching station will not result in load interrupted by configuration. However, prior to the in-service date of the new line from the Chatham TS to the switching station, interim measures including load rejection at Leamington TS will be required for certain contingencies. These interim measures will require exemptions from ORTAC load security and restoration criteria.

While the switching station insulates the Leamington tap loads from C21J/C22J contingencies, a contingency on either or both of the tap circuits will still result in load security and restoration needs. Addressing these needs will depend heavily on the amount of transfer capability on the distribution system in the area as well as the Kingsville reconfiguration which may provide a restoration path. The remaining load security and restoration needs on the Leamington tap should therefore be examined in the 115 kV sub-system studies subsequent to the IRRP as specified in Section 7.2.

7.5 OPTIONS FOR ADDRESSING ASSET REPLACEMENT NEEDS

When a piece of equipment reaches end of life and requires replacement, a number of alternatives often warrant consideration. The transmission or distribution system will likely have changed over the decades the equipment has been in service, community needs may have evolved, equipment standards changed, and opportunities for non-traditional options, such as CDM, may increasingly play a role in determining the future of a specific asset when it comes to time for renewal.

In developing options, three main alternatives were considered:

- Replacement with a like-for-like asset or with the closest available standard;
- Reconfiguration of the existing assets to right-size the replacement option based on: forecast load growth, changes to the use of the asset since it was originally installed, or to realize reliability or other system benefits that an alternate configuration may provide; or
- Retirement of a facility, considering the impact on load supply and reliability.

Most of the asset replacement needs identified for the Windsor-Essex sub-region impact transmission assets are critical to maintaining a reliable and sufficient supply of electricity. As such, complete retirement of these assets identified as replacement candidates was ruled out as a feasible alternative, even with consideration of existing CDM and DG forecasts or capacity that may exist at adjacent stations. Further to the replacement options above, the Working Group determined that since these needs are related to asset age and condition, non-wires alternatives are not a viable option.

For end-of-life replacement needs identified in the mid to long term, particularly Lauzon TS T5/T8 step-down transformers, near-term options were identified to help better inform replacement decisions in the next planning cycle or closer to when these facilities require a decision to be made on the scope of reinvestment.

7.5.1 Lauzon Transformers

Prior to June 2019, the T1/T2 autotransformers and T6 and T7 step-down transformers were identified in the Needs Assessment as reaching end of life within the study period. During development of the IRRP, Hydro One informed the IESO of potential additional end-of-life needs at the T6 and T8 step-down transformers – thereby emphasizing the need to consider total station configuration and supply capability at Lauzon TS. The timing of all these end-of-life needs was ultimately redefined (as outlined previously in Section 6.2.3.1). A number of replacement solutions were considered for these transformers, including a complete like-for-like replacement option, as well as a mixture of options that included upsizing.

Lauzon TS currently has four 230 kV/27.6 kV step-down transformers that can supply up to 100 MW of load at each of its two DESNs. Since the higher load (both current and forecast) on DESN 1 results in the existing transformer capacity need for T5/T6, an option to balance loads between DESN 1 and DESN 2 through distribution feeders was considered. This would allow both DESNs to be fully and evenly loaded without a transformer upsizing. This option is ultimately not recommended due to the following considerations:

- 200 MW cannot currently be supplied without interim measures, as identified through the Lauzon TS supply capacity need described in Section 6.2.1.2;
- The demand forecast for Lauzon TS (total) exceeds 200 MW in every year of the study period regardless; and

- The required transfer of approximately 30 MW from DESN 1 to DESN 2 cannot be addressed solely by EPL and/or Hydro One Distribution (who, together, serve less than 30 MW in total from DESN 1), and would require ENWIN to obtain new feeder positions at DESN 2 (from which its customers are not currently supplied by).

If continuing the loading at the two DESNs as is, upsizing T5/T6 would be an option to solve both the existing DESN 1 capacity and part of the Lauzon TS end-of-life needs. No capacity need was identified for T7/T8, however, to provide justification for their upsizing at this time. Simultaneously, regardless of any action to replace the end-of-life transformers, any benefit of additional transformer capacity would still be limited by the overall Lauzon TS supply capacity need. Because the voltage phenomenon that restricts supply capability to Lauzon TS may potentially be improved by the nearby Kingsville TS and its final reconfiguration (as identified in Section 7.2), recommendations for the T7/T8 step-down transformers would be better informed by the upcoming detailed 115 kV sub-system capacity and Leamington restoration study.

Consequently, this IRRP recommends that Hydro One proceed with an upsizing of the T5/T6 step-down transformers from 83 MVA to 125 MVA. Determination of the replacement options for the T7/T8 step-down transformers will follow the 115 kV sub-system capacity and Leamington restoration study.

Finally, with the timing of the end-of-life needs for the Lauzon autotransformers redefined to be 2029, this IRRP recommends that the potential to right-size T1/T2 be considered within the 115 kV sub-system capacity and Leamington restoration study, which addresses supply into the 115 kV sub-system as a whole.

7.6 RECOMMENDED PLAN AND IMPLEMENTATION TO ADDRESS LOCAL NEEDS

The Working Group recommends the actions described below to meet identified needs in the Windsor-Essex region. Successful implementation of these actions, in addition to achievement of targeted energy-efficiency measures, is expected to address the region's near- to mid-term electricity needs.

7.6.1 Implementation of Recommended Plan

To address the near-term electricity needs of the Windsor-Essex region are addressed, it is important that the plan recommendations be implemented as soon as possible. Specific actions and deliverables are outlined in Table 7-1, along with the recommended timing.

Table 7-1: Summary of Needs and Recommended Actions in Windsor-Essex Region

Need(s)	Item #	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe for Recommendation
Kingsville-Leamington sub-system supply and station capacity need	1	Initiate engagement and approvals for a new switching station at the Leamington Junction	Hydro One	2022
	2	Collect information on future DR opportunities through a potential targeted call focused on reducing electricity demand from indoor agriculture	IESO	2020
	3	Monitor growth; regional and bulk transmission projects; behind-the meter generation; DERs and energy efficiency, and gather information on developments in the agriculture industry and emerging technologies, to inform next planning cycle; trigger next planning cycle early if required	IESO	Annually
	4	Employ interim measures to maintain current load capability	IESO	Immediate
	5	Refer to item #6	-	-
Kingsville TS station capacity need	6	Monitor growth, and develop high-level options for the 115 kV sub-system capacity and Leamington restoration needs	IESO	2020

Need(s)	Item #	Recommended Action(s)/Deliverable(s)	Lead Responsibility	Timeframe for Recommendation
Lauzon 115 kV sub-system supply capacity need	7	Refer to item #1 and 6	-	-
Lauzon TS DESN 1 transformer capacity needs	8	Upsize end-of-life stepdown transformers T5/T6	Hydro One	2020
Lauzon TS station capacity needs	9	Refer to item #6	-	-
Kent TS station capacity need	10	Initiate engagement and approvals for a new DESN station	Entegrus	2023
Belle River TS station capacity need	11	Monitor load growth and impact of energy efficiency until the next planning cycle	IESO	Annually
Leamington load restoration need	12	Refer to item #6	IESO	2020
Lauzon TS end-of-life asset replacement needs	13	Replacement of end-of-life stepdown transformers T5/T6, as per item #8	-	-
	14	Determine replacement of end-of-life stepdown transformers T7/T8, according to findings from item #6	IESO	2020
	15	Determine replacement of end-of-life autotransformers T1/T2, according to findings from item #6	Hydro One	2020
Keith TS end-of-life asset replacement needs	15	Upsize end-of-life 230/115 kV autotransformers T11/T12 from 125 MVA to 250 MVA	Hydro One	2024
	16	Decommission the end-of-life T1 (115 kV/27.6 kV) transformer	Hydro One	2024

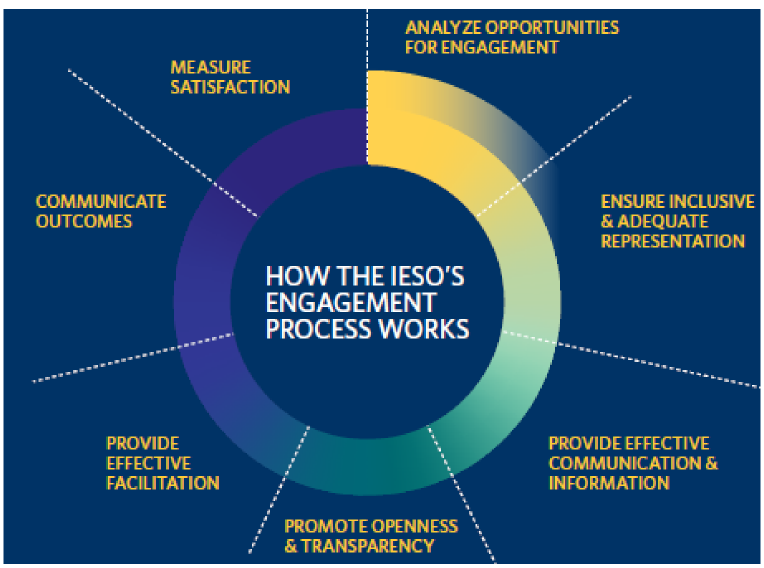
8. Community and Stakeholder Engagement

Community engagement is an important aspect of the regional planning process. Providing opportunities for input in regional planning enables the views and preferences of the community to be considered in the development of an IRRP and help to lay the foundation for successful implementation. This section outlines the IESO's engagement principles as well as the engagement activities undertaken for the Windsor-Essex IRRP.

8.1 ENGAGEMENT PRINCIPLES

IESO Engagement Principles[16] guide the process to ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, and build trusted relationships.

Figure 9-1: IESO Engagement Principles



[16] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Overview/Engagement-Principles

8.2 CREATING OPPORTUNITIES FOR ENGAGEMENT

The dialogue on the Windsor-Essex IRRP commenced in January 2018. A dedicated IRRP Windsor-Essex engagement web page[17] on the IESO website included rationale for the development of the Windsor-Essex IRRP, Terms of Reference and a listing of the organizations involved. In addition to providing an inventory of all engagement activities in a transparent manner, the webpage provides background information, presentations, public webinars and meeting notes and feedback received.

A dedicated email subscription service for the broader Windsor-Essex planning region was used to send information to interested communities and stakeholders who subscribed to receive email updates. Targeted outreach to municipalities, Indigenous communities and other business sectors in the region was conducted at the outset of this engagement and throughout the planning process.

In addition, regular updates on the plan were included in the IESO's weekly e-bulletin, which reaches interested parties from across Ontario's electricity sector.

8.3 ENGAGE EARLY AND OFTEN

Early communication and engagement activities for the Windsor-Essex IRRP began with invitations to learn more about the draft Windsor-Essex region Scoping Assessment Outcome Report, and to provide comments before it was finalized in March 2018. This feedback was considered in the final Scoping Assessment, which identified the need for an IRRP for the Windsor-Essex region. And included Terms of Reference for the development of the IRRP.

To begin the development of the IRRP, an engagement plan was prepared to outline the background, objectives and proposed timelines and seek input from communities to inform the final IRRP. The engagement plan included the formation of a local advisory committee to better inform forecast demand and energy needs for the continued growth of the greenhouse sector in

[17] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Windsor-Essex

the Leamington/Kingsville area, particularly with respect to load profile characteristics and potential non-wires solutions in this area. Membership consisted of representation from local municipalities, associations and businesses including: the Municipality of Leamington and Town of Kingsville, the growers' association, local growers of different scales, and local boards of trade and chambers of commerce.

Broader engagement efforts for the Windsor-Essex region were also incorporated into the engagement plan which included webinars to facilitate access to information and provide opportunities to submit feedback.

8.4 BRINGING COMMUNITIES TO THE TABLE

As key parties in the development of this IRRP, targeted invitations went out to communities including the Municipality of Leamington, Town of Kingsville, City of Chatham-Kent, City of Windsor, and the Caldwell First Nations to present an overview of the IRRP and invite opportunities to provide input for consideration. Meetings and regular communications were held throughout the IRRP process.

In addition, detailed discussions with the Kingsville-Leamington LAC were conducted throughout the development of the IRRP and were paramount to informing and identifying potential solutions for this targeted study area. Membership in this committee was voluntary and participants (including observers) devoted significant time and effort to providing input for consideration in the recommendations targeted for this area.

In the final phase of the IRRP, individual follow-up meetings were held with four municipalities to discuss the draft plan and proposed approaches for near-term options. A public webinar was also held to further expand the discussion, invite opportunity for feedback and facilitate broader awareness of the regional plan at a local level.

All background information as well as engagement presentations and recorded webinars are available on the Windsor-Essex IRRP engagement webpage.[18]

8.5 SUMMARY OF ENGAGEMENT FEEDBACK

More than 100 individuals actively participated in this IRRP engagement initiative and over 1,000 elected to receive regular updates throughout the process. In addition, nine outreach meetings were held with various representatives from four municipalities. This resulted in valuable input in the development of this IRRP, including:

- A fulsome understanding of the needs and priorities of the targeted areas within this planning region;
- Information to explore options to alleviate capacity constraints in the Kingsville/Leamington area;
- Identification of barriers and opportunities for potential demand-response options within the greenhouse industry;
- Feedback on the design of potential demand-response pilot projects to explore;
- Opportunities to present the draft recommendations for review and consideration in this final IRRP; and
- Opportunities to strengthen relationships with all interested parties for ongoing dialogue beyond this IRRP.

The IESO received a lot of support from the agricultural sector throughout the process and looks forward to continuing to work with the industry as part of the implementation of applicable recommendations and future plans.

[18] http://www.ieso.ca/Sector-Participants/Engagement-Initiatives/Engagements/Integrated-Regional-Resource-Plan-Windsor-Essex

9. Conclusion

This report documents an IRRP that has been carried out for the Windsor-Essex region. The IRRP identifies electricity needs in the Windsor-Essex region over a 20-year period, recommends options to address near-term needs, and lays out actions to evaluate, monitor, and address needs that may arise in the long term.

To further review "wires" solutions that address end-of-life asset replacement and other transmission supply needs, the IRRP recommends that Hydro One initiate a RIP. The IESO will continue to provide input and support throughout the RIP process, and assist with any regulatory matters that may arise during plan implementation.

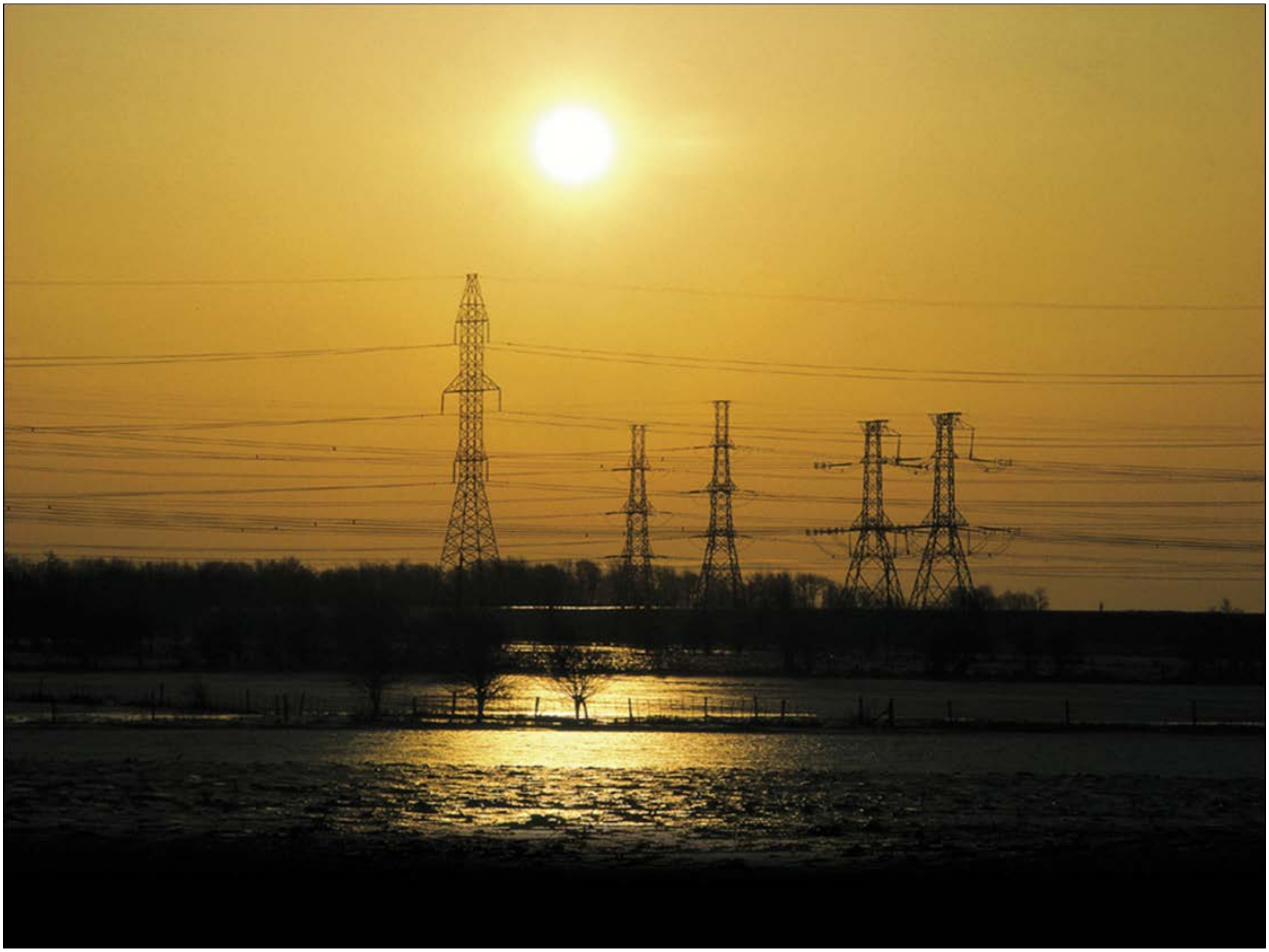
Multiple actions are recommended to address near- to mid-term needs through a combination of non-wires and wires options. Near-term actions are recommended to determine mid-term solutions, in particular the study of the 115 kV sub-system capacity and Leamington load restoration needs, and to monitor developments required to inform the long-term plan.

To support the development of the plan, the IRRP recommends a number of actions, including a Grid Innovation Fund targeted call focused on reducing electricity demand from indoor agriculture, the ongoing development of alternatives for mid-term actions, and continued monitoring of load growth and energy-efficiency activities and results. Responsibility for these actions has been assigned to the appropriate members of the Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the IRRP for the Windsor-Essex region.

The Windsor-Essex region Working Group will continue to meet at regular intervals to complete the recommended 115 kV study, monitor developments in the sub-region, and track progress toward plan deliverables. In particular, actions and deliverables associated with the medium and long term will require an annual review of system demand and generation, as well as development of ongoing transmission reinforcements to determine whether recommendations require further review by the Working Group. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the OEB-mandated five-year schedule.

APPENDIX G – 2020 REGIONAL INFRASTRUCTURE PLAN

-



Windsor-Essex

REGIONAL INFRASTRUCTURE PLAN

March 18, 2020

hydro one

(This page is intentionally left blank)

Prepared and supported by:

Company
E.L.K. Energy Inc.
Entegrus Powerlines Inc.
EnWin Utilities Ltd.
Essex Powerlines Corporation
Hydro One Networks Inc. (Distribution)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Lead Transmitter)

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE WINDSOR-ESSEX REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- E.L.K. Energy Inc.
- Entegrus Powerlines Inc.
- EnWin Utilities Ltd.
- Essex Powerlines Corporation
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- Hydro One Networks Inc. (Transmission)

This RIP is the final phase of the second cycle of Windsor-Essex regional planning process, which follows the completion of the Windsor-Essex Integrated Regional Resource Plan ("IRRP") in September 2019 and the Windsor-Essex Region Needs Assessment ("NA") in October 2017. This RIP provides a consolidated summary of the needs and recommended plans for Windsor-Essex Region in the near-term (up to 5 years) and the mid-term (5-10 years).

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and the solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects have been completed and underway:

- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): two 27.6 kV feeder breakers have been replaced.
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to accommodate the construction of Gordie Howe International Bridge (I/S 2019)
- Leamington TS expansion: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)

- Kingsville TS transformers replacement (in progress, I/S 2022): Transformers T2 and T4 have been replaced with 50/83 MVA T6 in 2018. Transformers T1 and T3 replacement is underway.
- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (expected I/S 2024).

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1: Recommended Plans in Windsor-Essex Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate ($M)
1	Supply capacity need to Kingsville- Leamington area	• Build new switching station at Leamington Junction (Lakeshore TS), and new DESN station (South Middle Road TS) • Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS	2022-2025	$295M
2	Lauzon TS T5/T6 transformers end-of-life and station capacity	• Replace Lauzon TS T5 & T6 transformers replacement with larger 75/125 MVA units	2024	$34M
3	Kent TS station capacity	• Install new feeder positions to supply load growth at Kent TS • Further evaluate the plan for a new DESN south of Chatham as part of the Chatham-Lambton-Sarnia regional planning process	-	-
4	Belle River TS station capacity	• Monitor load growth and re-evaluate the need in the next regional planning cycle	-	-

The Study Team recommends that Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status.

TABLE OF CONTENTS

List of Figures

List of Tables

1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE WINDSOR-ESSEX REGION BETWEEN 2020 AND 2030.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Study Team that consists of Hydro One, E.L.K. Energy Inc., Entegrus Powerlines Inc., EnWin Utilities Ltd., Essex Powerlines Corporation, Hydro One Networks Inc. (Distribution), and the Independent Electricity System Operator ("IESO") in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The Windsor-Essex Region is comprised of the area southwest of the Municipality of Chatham-Kent. It includes the City of Windsor, Town of LaSalle, Town of Amherstburg, Town of Tecumseh, Town of Essex, Town of Lakeshore, Town of Kingsville, Municipality of Leamington, Township of Pelee, and the western portion of the Municipality of Chatham-Kent.

Electrical supply to the region is provided by seventeen 230 kV and 115 kV step-down transformer stations ("TS"). The map of the region is shown in Figure 1-1 below.

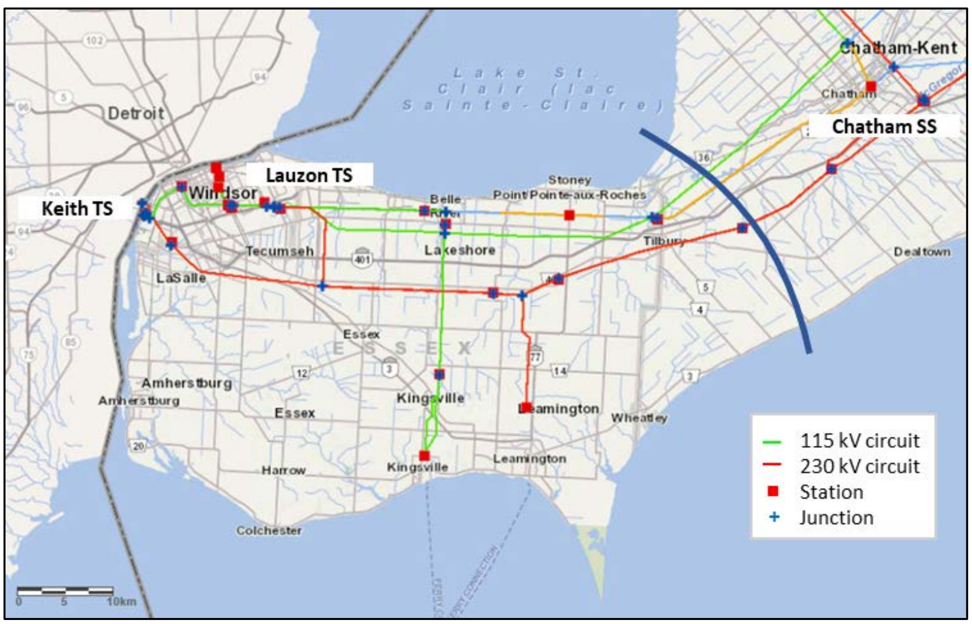


Figure 1-1: Windsor-Essex Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the Windsor-Essex Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;

- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and/or distribution facilities that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the near to mid-term planning horizon (i.e., within the next 10 year period);
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 discusses the needs and provides the alternatives and preferred solutions.
- Section 7 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

[1] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

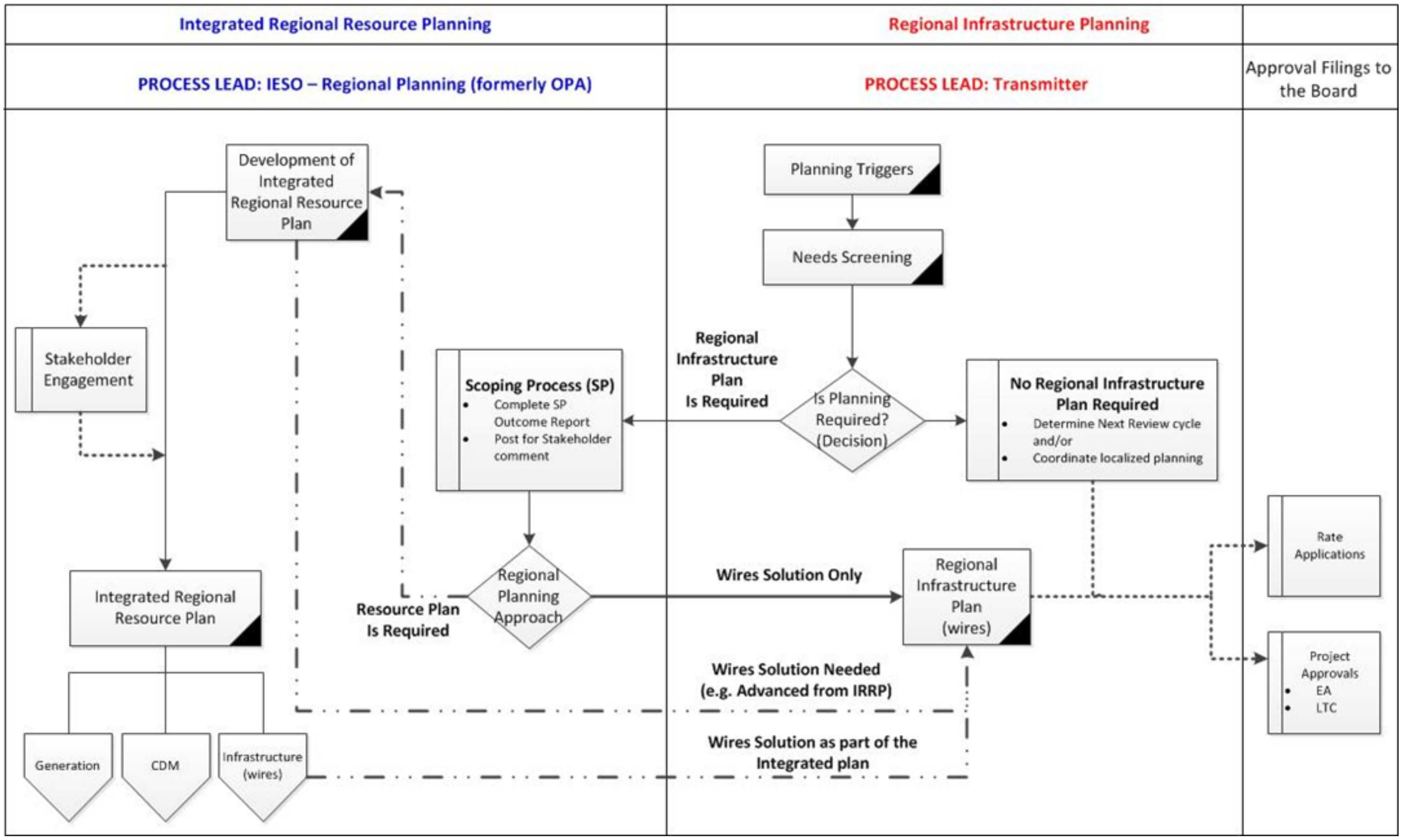


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

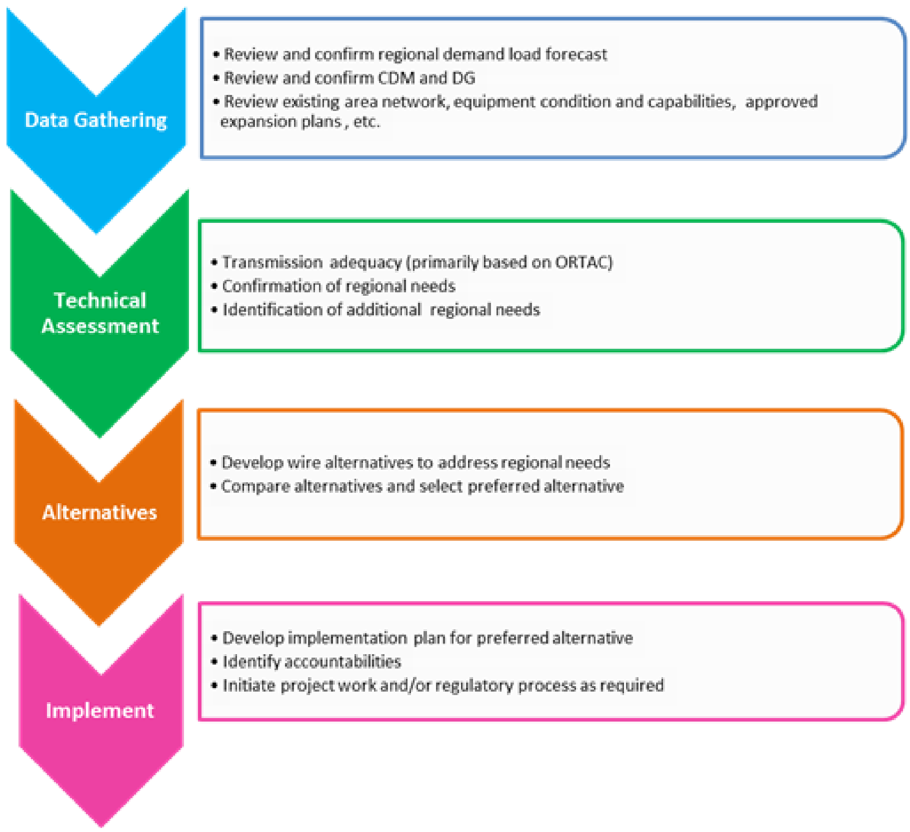


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE WINDSOR-ESSEX REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY CANADA-UNITED STATES (MICHIGAN) BORDER TO THE WEST AND THE MUNICIPALITY OF CHATHAM-KENT TO THE EAST. IT IS THE SOUTHERNMOST REGION OF ONTARIO.

The main transmission corridor in the region connects with the rest of the Hydro One system at Chatham Switching Station ("SS") and connects the Ontario transmission system with the Michigan transmission system at Keith TS.

The region's 115 kV network connects to the 230 kV transmission system at Keith TS and Lauzon TS via two autotransformers in each station. Fourteen 115 kV step-down transformer stations ("TS") and three 230 kV TS's serve the electrical load in the region through the 115 kV and 230 kV transmission network, as shown in Figure 3-1. Leamington TS is a new transformer station serving demand in the Kingsville-Leamington area, and came into service in 2017. Installation of a new second DESN at Leamington TS was completed in 2019.

There are 13 customer-owned generating plants in the region, connecting at the 230 kV and 115 kV levels with a combined contract capacity of 1,574 MW. Table 3-1 lists the region's transmission connected generations.

Table 3-1: Transmission Connected Generations

Station Name	Technology	Connection Point	Contract Capacity (MW)
Brighton Beach Power Station	Combined Cycle	Keith TS	541.25
West Windsor Power	Combined Cycle	J2N (Keith TS)	122.78
TransAlta Windsor Essex Cogeneration	CHP	Z1E	72.28
East Windsor Cogeneration	CHP	E8F/E9F	84
Gosfield Wind Project	Wind	K2Z	50.6
Pointe Aux Roches Wind	Wind	K6Z	48.6
Comber East (C24Z) Wind Project	Wind	C24Z	82.8
Comber West (C23Z) Wind Project	Wind	C23Z	82.8
KEPA Port Alma Wind Farm (I and II)	Wind	C24Z	200.6
RWEC Dillon Wind Farm	Wind	C23Z	78
Belle River Wind	Wind	C23Z	99.8
Romney Wind Farm	Wind	C21J	60
Windsor Solar	Solar	Z1E	50

The Windsor-Essex Region summer coincident peak demand in 2019 was about 1032 MW, adjusted to extreme weather. The region is served by five Local Distribution Companies ("LDC"): E.L.K. Energy Inc., Entegrus Powerlines Inc., EnWin Utilities Ltd., Essex Powerlines Corporation, and Hydro One Distribution. EnWin and Hydro One Distribution are directly connected to the transmission system, while three other LDCs have low voltage connections.

A single line diagram showing the electrical facilities in Windsor-Essex Region is provided in Figure 3-1.

-

March 18, 2020

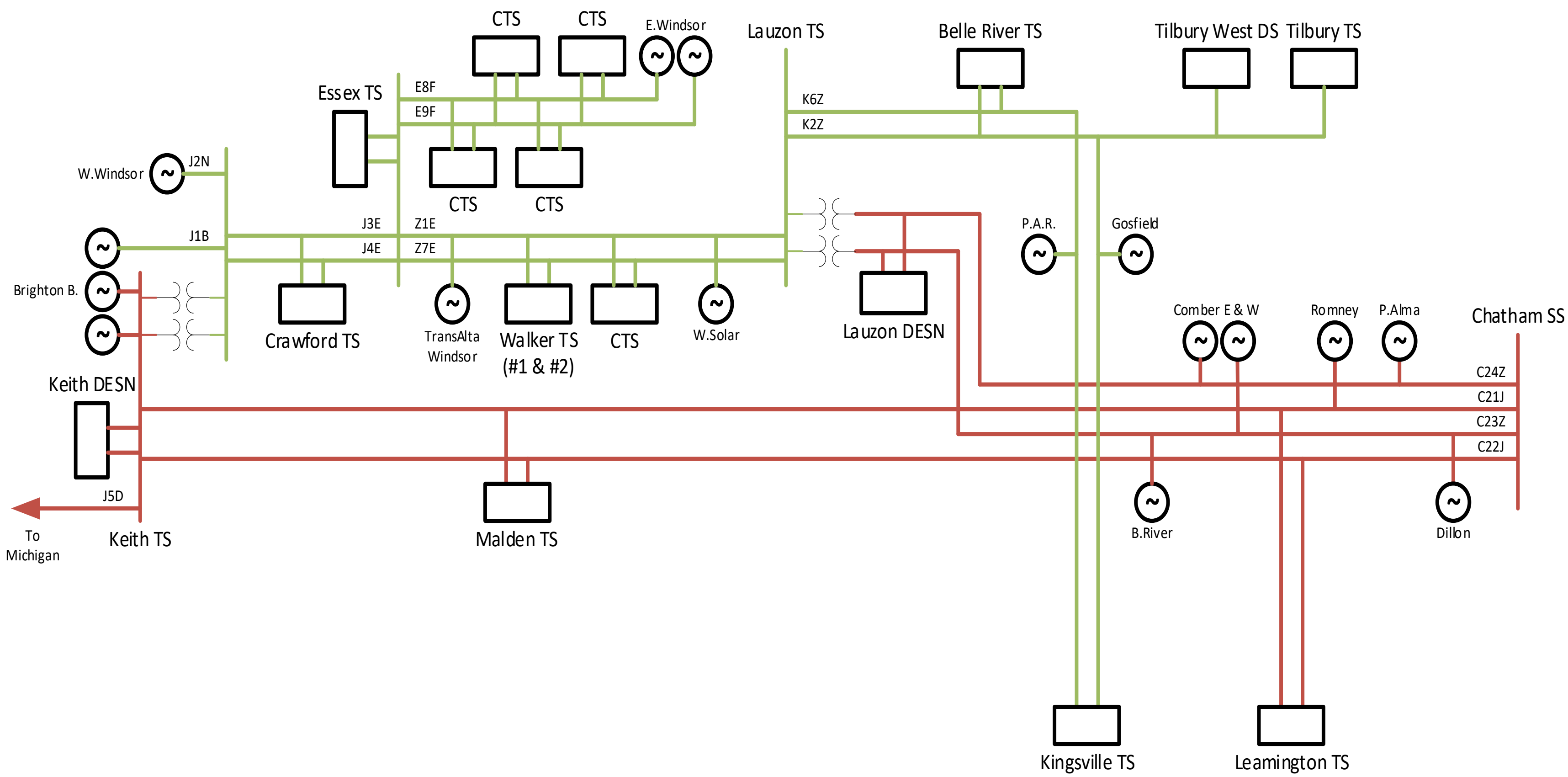


Figure 3-1: Single Line Diagram of Windsor-Essex Region's Existing Transmission System

4 TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY OVER THE LAST TEN YEARS

OVER THE LAST TEN YEARS, A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE WINDSOR-ESSEX REGION.

A summary and description of the major projects completed and/or currently underway over the last ten years is provided below.

- Malden TS transformers replacement (I/S 2011): T1 and T2 were replaced in 2010 and 2011, respectively.
- Walker TS #1: Reactor installation for short circuit mitigation (I/S 2011).
- Kingsville TS: Reactor installation for short circuit mitigation (I/S 2011).
- Keith TS: Reactor installation for short circuit mitigation (I/S 2012).
- Lauzon TS breakers replacement (I/S 2012): Three breakers were replaced (SC2Q, SC3E, and SC4J).
- Keith TS DESN transformers replacement (I/S 2013): T23 and T22 were replaced in 2008 and 2013, respectively.
- Keith TS breakers replacement (I/S 2015): Six breakers were replaced (SC11K, SC11SC, SC1B, T11P, T12P, and SC2Y).
- Crawford TS transformer T3 replacement and neutral grounding reactors installation on T3 and T4 (I/S 2017)
- Malden TS breakers replacement (I/S 2018): two 27.6 kV feeder breakers have been replaced.
- Supply to Essex County Transmission Reinforcement (I/S 2017): Build new 13 km double-circuit 230 kV transmission lines to Leamington area tapped to existing C21J/C22J circuits, and new 75/100/125 MVA Leamington TS and its distribution feeders.
- Reconfiguration of 230 kV and 115 kV circuits and 27.6 kV feeders at Keith TS to accommodate the construction of Gordie Howe International Bridge (I/S 2019)
- Leamington TS expansion: Build the second 75/100/125 MVA DESN at Leamington TS (I/S 2019)
- Kingsville TS transformers replacement (in progress, I/S 2022): Transformers T2 and T4 have been replaced with 50/83 MVA T6 in 2018. Transformers T1 and T3 replacement is underway.
- Keith TS autotransformers replacement (in progress, I/S 2023): 125 MVA autotransformers T11 and T12 will be replaced by 250 MVA units.
- Tilbury TS decommissioning (in progress, I/S 2024): Decommissioning of station due to end-of-life and transfer serviced load to Tilbury West DS supply.
- Keith TS transformer T1 decommissioning (planned I/S 2024)

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The electricity demand in the Windsor-Essex Region is anticipated to grow at an average rate of 1.5% over the next ten years. The Windsor-Essex Region has been historically a summer-peaking region. With the new development in the greenhouse sector particularly in the Kingsville-Leamington area, the region peak demand has gradually shifted to the winter season. Figure 5-1 shows the updated Windsor-Essex Region's summer non-coincident and coincident peak load forecast for the 2020-2030 study period.

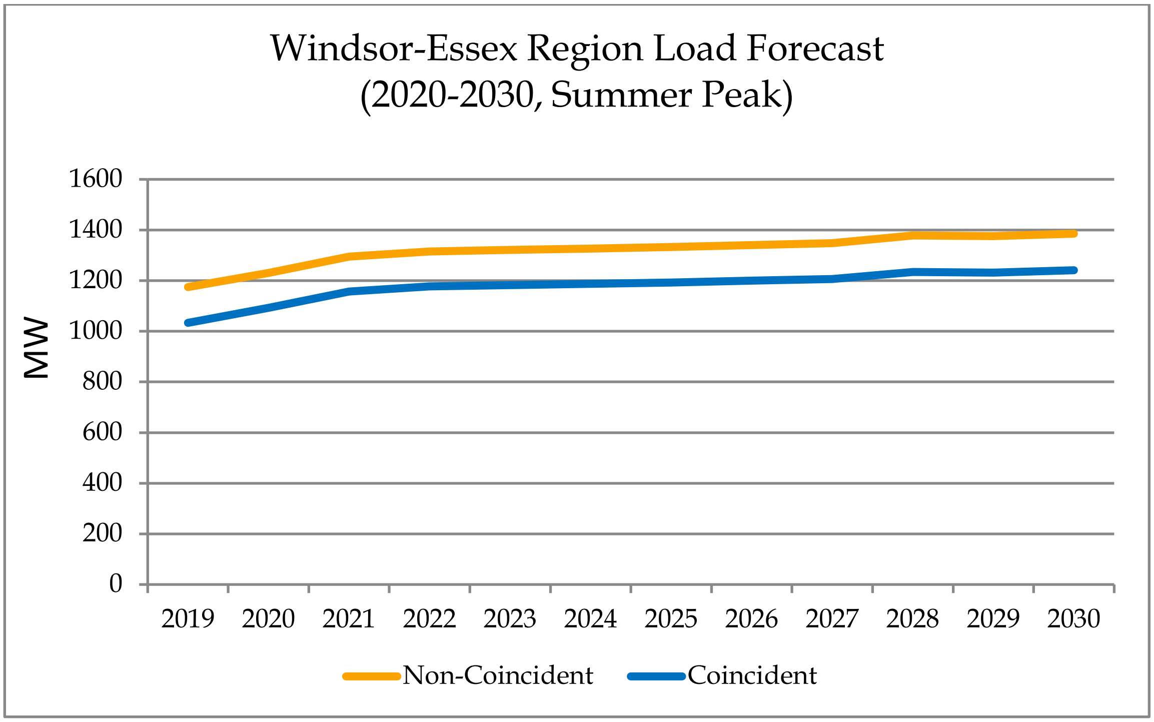


Figure 5-1: Windsor-Essex Region Load Forecast (Summer Peak)

The load forecast shows that the Region peak summer load increases from 1093 MW in 2020 to 1241 MW by 2030. The corresponding non-coincident summer peak loads increase from 1230 MW to about 1385 MW over the same period. The non-coincident and coincident net load forecasts for the individual stations in the Windsor-Essex Region are given in Appendix D, Table D-1 and Table E-1. Specifically for Kingsville TS and Leamington TS, based on their load characteristics, the annual peak of the stations occurs in the winter, thus for the two stations, the winter load forecast is also provided in Table D-2 and E-2 (for non-coincident and coincident forecast, respectively).

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2020-2030.

- Load forecast includes the contribution from the distributed generation (DG) and conservation, and demand management (CDM) program, as provided by the 2019 Windsor-Essex IRRP (i.e., net load forecast).
- All facilities identified in Section 4 and that are planned to be placed in-service within the study period are assumed in-service.
- Normal planning supply capacity for transformer stations is determined by the summer 10-day Limited Time Rating (LTR), assuming a 90% lagging power factor.

6 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE WINDSOR-ESSEX REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the Windsor-Essex Region and plans to address these needs for the study period of 2020-2030. Table 6.1 provides a summary of the needs and the corresponding sub-sections where recommendation and plans are discussed.

Table 6-1: Identified Near and Mid-Term Needs in Windsor-Essex Region

Section	Facilities	Need	Timing
6.1	• New Switching Station ("Lakeshore TS") • DESNs ("South Middle Road TS") • New 2-circuit 230 kV transmission line (Chatham SS x Lakeshore TS)	Supply capacity to Kingsville-Leamington area load	2023
6.2	Lauzon TS	Step-down transformers T6/T8 end-of-life and T5/T6 station capacity	2024
		Step-down transformers T5/T7 and autotransformers T1/T2 end-of-life	2029
	Lauzon 115 kV Subsystem (i.e., stations radially supplied from Lauzon TS via K2Z/K6Z)	Load meeting capability due to voltage change violations	Today
6.3	Kent TS	Station capacity	2025
6.4	Belle River TS	Station capacity	2028

6.1 Supply Capacity to Kingsville-Leamington Area Load

6.1.1 Description

In the first cycle of regional planning for the Windsor-Essex Region, the Study Team recommended the Supply to Essex County Transmission Reinforcement (SECTR) project to supply the unprecedented load growth in the Kingsville-Leamington area driven by greenhouse development. The SECTR project included 13 km extension of existing 230 kV double-circuits C21J/C22J south to Leamington, and a new Leamington TS DESN, adding 200 MW of supply capacity in the Kingsville-Leamington area. The SECTR project was placed in service late 2017.

The added supply was fully allocated by the time SECTR project was in-service. The continuing significant load growth in the Kingsville – Leamington and the associated load forecast indicated that changes would be required in the recommended plan as set out in the first cycle RIP of December 2015. This situation triggered the second cycle of regional planning for the Windsor – Essex region, with the Needs Assessment completed in October 2017.

To meet the growing electricity demand in the area, Hydro One proceeded to build the second DESN at Leamington TS. This expansion of Leamington TS, placed in service in late 2019, doubles the station capacity to 400 MW. Again, the rapidly growing demand in Kingsville-Leamington area exceeded the expanded station capacity – the existing connection applications in total are about 100 MW over the expanded station capacity. The magnitude of the electricity demand in this area not only exceeded station capacity, but also exceeded load meeting capacity of the transmission system. As consequences of this increasing demand, station capacity need, upstream transmission need, and load security need in this area have been identified by the Study Team. Until the transmission system is sufficiently upgraded, the system inadequacy would be managed with Special Protection Systems.

6.1.2 Alternatives and Recommendation

During the IRRP process, the Study Team has assessed the potential of non-wires alternatives including demand response, energy efficiency, and local generation to meet the supply capacity need in the Kingsville-Leamington area.

The Study Team recommends building a new switching station at Leamington JCT and new DESNs to meet the requirements of forecast load growth in the Kingsville – Leamington area. The team also recommends building a new 2 – circuit 230 kV line between Chatham SS and the new station at Leamington Junction.

<u>Recommended Stations Project and Current Status</u>

Hydro One has commenced a project to build a switching station in the vicinity of the existing Leamington Junction in the Town of Lakeshore in Essex County. All the 230 kV circuits C21J, C22J, C23Z and C24Z at this junction will be terminated at this station with full switching. The new station, to be known as Lakeshore Transformer Station, will have provision for additional development in the future. A second station will be built in close proximity to Lakeshore TS for the establishment of two new DESNs. This new station will be known as South Middle Road Transformer Station. Both stations will be located in the same Hydro One property in the Town of Lakeshore (Figure 6-1).

Each of the two DESNs at South Middle Road TS will consist of 2 x 75/100/125 MVA, 230/27.6 – 27.6 kV power transformers, twelve LV feeder positions and 2 LV capacitor banks, plus required switchgear.

Hydro One has completed necessary engagement activities and Class Environmental Assessment work for the establishment of the two stations. Hydro One obtained EA approval for the stations with the submission of the final Environmental Study Report to the Ministry of the Environment, Conservation and Parks, in January 2020. Construction is planned to commence in Q3 2020 for both Lakeshore TS and the first of the two DESNs at South Middle Road TS, and both facilities are planned to be in service in Q2 2022.

The second DESN at South Middle Road TS is planned to be in service in Q3 2025.

Recommended Line Project and Current Status

Hydro One is in the planning stages of the project to build a 2 x 230 kV line, about 49 km, between Chatham SS and Lakeshore TS. Engagement activities and Class Environmental Assessment studies are planned to commence in January 2020. EA approval and the OEB "Leave to construct" approval for the new line are expected in 2021 and 2022, respectively. The line is planned to be placed in service in Q4 2025.

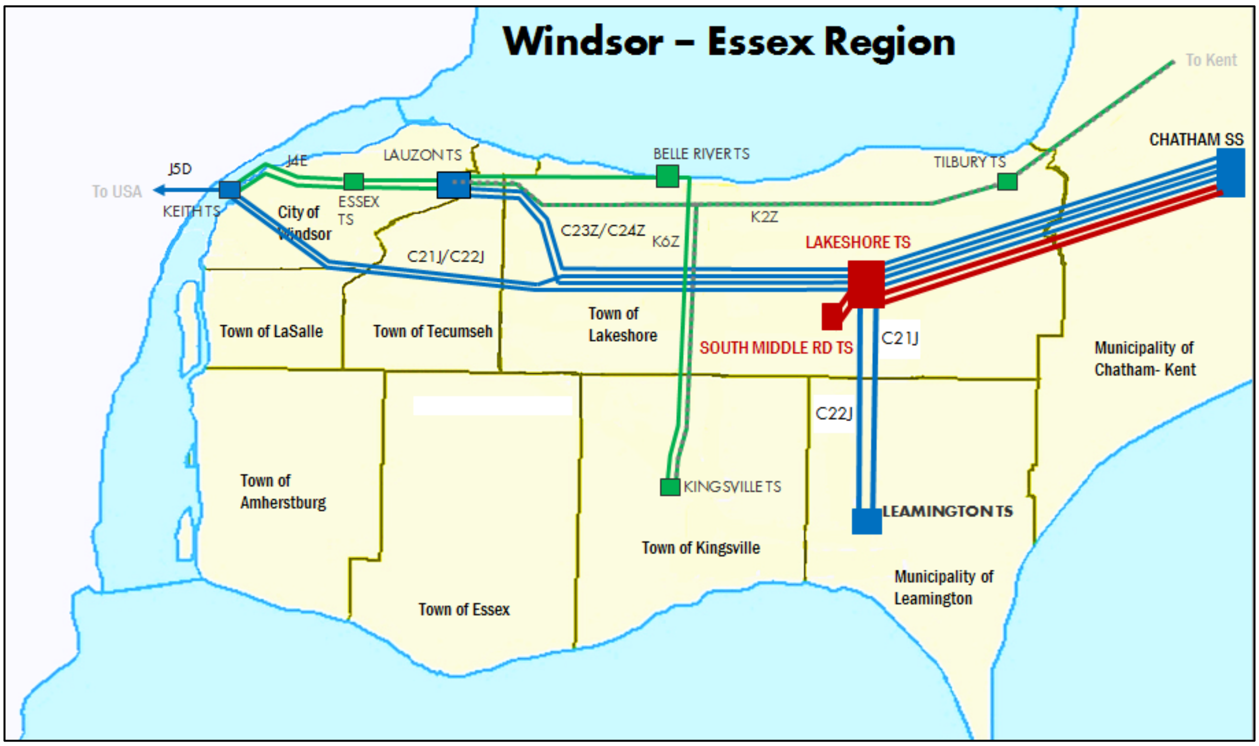


Figure 6-1: Planned Lakeshore TS, South Middle Road TS and Chatham SS x Lakeshore TS Line

6.2 Lauzon TS Transformers End-of-Life & Lauzon 115 kV Subsystem Supply Capacity Need

6.2.1 Description

Lauzon TS is located in the eastern part of the City of Windsor, and includes 230/115 kV autotransformation facility (T1, T2), as well as two 230/27.6 kV DESNs (T5/T6 and T7/T8). Lauzon TS is connected to the 230 kV circuits C23Z/C24Z, and 115 kV circuits Z1E/Z7E and K2Z/K6Z.

All of the Lauzon TS autotransformers and step-down transformers are reaching their end-of-life within the next 10 years. The T6 and T8 transformers are expected to reach their end-of-life by 2024, while the rest of the units (T1, T2, T5, and T7) are expected to reach their end-of-life by 2029. Figure 6-2 shows the overview of the station and the surrounding area.

Figure 6-2: Lauzon TS

Over the next 10 years, the combined station summer peak load is expected to remain fairly constant at approximately 220 MW. The T5/T6 DESN supplies approximately 130 MW of load, and the T7/T8 DESN supplies 90 MW of load. Considering each DESN is rated approximately 100 MW, a station capacity need has also been identified at the T5/T6 DESN level as well at the combined station level.

In addition, there is an existing supply capacity need in the Lauzon 115 kV subsystem, as shown in Figure 6-3, which includes stations supplied by the 115 kV K2Z/K6Z (i.e., Kingsville TS, Belle River TS, and Tilbury West DS). This need arises due to voltage change violations of ORTAC following certain contingencies. This need is being evaluated in-detail through a separate study, to be provided as an addendum to the 2019 Windsor-Essex IRRP, expected for completion in Q3 2020.

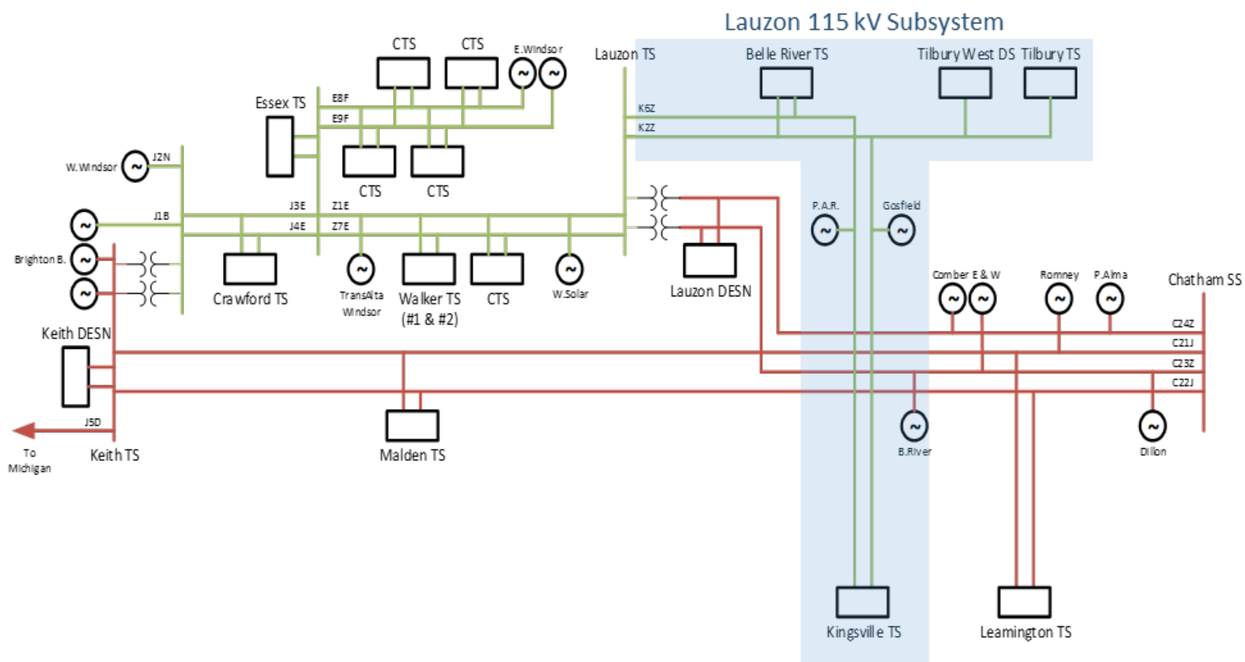


Figure 6-3: Lauzon 115 kV Subsystem

6.2.2 Alternatives and Recommendation

The following alternatives are considered to address the above end-of-life and station capacity needs:

1. **Maintain Status Quo:** This alternative was considered and rejected as it does not address the station capacity and risk of failure due to asset condition and would result in increased maintenance cost and reduce supply reliability for customers.
2. **Like-for-Like Replacement:** This alternative was considered and rejected as it does not address the station capacity need.
3. **Load Balancing between two DESNs:** Load balancing between two DESNs can be achieved through distribution feeders' re-configuration. This alternative was considered and rejected as the load forecast shows demand at Lauzon TS exceeds 200 MW in the whole study period.
4. **Distribution Load Transfer to Nearby Stations:** This alternative is not feasible as there are no sufficient capability to transfer the excess load to nearby stations.
5. **Replace and Upgrade the End-of-Life Transformers T5/T6:** This option will address the station capacity need and the T5/T6 end-of-life need.

The Study Team recommends Hydro One proceed with Alternative 5 – to replace the 50/83 MVA T5/T6 with 75/125 MVA units, with expected in-service date of 2024. The strategy of T1/T2 and T7/T8 replacement will be determined after the Lauzon 115 kV subsystem study is completed (expected Q3 2020).

6.3 Kent TS Station Capacity Need

6.3.1 Description

Kent TS is part of the Chatham-Lambton-Sarnia Region, and at the inter-regional boundary with the Windsor-Essex Region. Kent TS is located approximately 6 km to the northwest of Chatham SS, and is electrically connected to 230 kV double circuits L28C/L29C between Chatham SS and Lambton TS. Kent TS consists of two 230 kV/27.6 kV DESNs (T1/T2 and T3/T4). The T1/T2 DESN is rated 153 MVA of capacity in summer; while the T3/T4 DESN is rated 58.7 MVA. Based on historical peak loading, and a request for load allocation, Entegrus was allocated 38 MW of incremental load at the T1/T2 DESN. Hydro One is currently coordinating with Entegrus to connect two new feeder positions at the T1/T2 DESN.

Figure 6-4 below shows the map and transmission system around Kent TS.

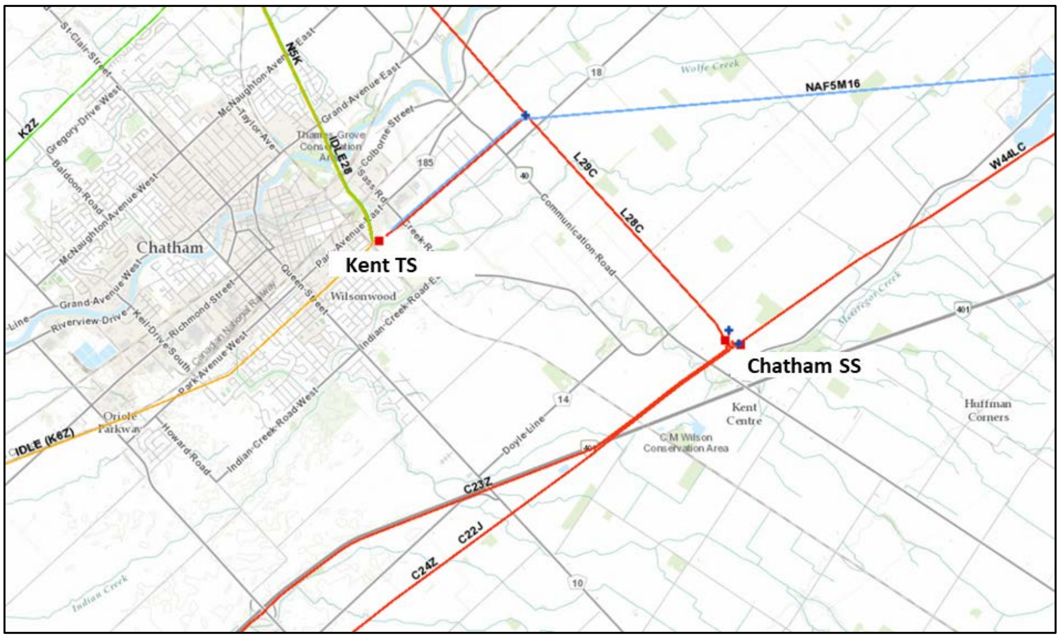


Figure 6-4: Kent TS Map

While Kent TS is part of the Chatham-Lambton-Sarnia Region, and not in the Windsor-Essex Region, there was an urgent capacity need identified by the LDCs in the region. There is a 55 MW load connection anticipated at Kent TS, and in addition, the load forecast predicts that the existing load will increase by 12.5 MW in the next five years. In 2020, the station capacity at Kent TS is expected to be fully utilized; and there will be an incremental capacity need of 30-40 MW over the next ten years.

6.3.2 Alternatives and Recommendation

The Study Team has evaluated the potential of upsizing Kent TS transformers and/or adding new DESN transformers at the station to provide the additional station capacity. Assessments concluded that those options were not feasible because long feeders would be required to connect the new load (located South of Chatham) to Kent TS, which would incur significant costs, higher losses along with challenges with station egress and feeder routing. Accordingly, the Study Team has determined that the recommended location for a new DESN is south of Chatham.

However, several transmission planning assessments are currently underway, including the Dresden area study which will be followed by regional planning for the Chatham-Kent-Lambton-Sarnia Region to be triggered in Q1/Q2 2020. In light of the fact that load forecasts for Chatham have shifted out the capacity need, the Study Team recommends that the plan for the new DESN South of Chatham to be further evaluated as part of the upcoming Chatham-Kent-Lambton-Sarnia regional planning process.

6.4 Belle River TS Station Capacity Need

6.4.1 Description

The existing Belle River TS comprises a 115 kV/27.6 kV DESN (T1/T2). It is supplied by two 115 kV circuits K2Z and K6Z. The station capacity is approximately 54 MW. The summer peak of its serving area is currently 45 MW. According to the load forecast in the study period, Belle River TS is expected to have moderate load growth. The station capacity is expected to be exceeded as early as in 2028.

6.4.2 Alternatives and Recommendation

1. **Maintain Status Quo:** Do nothing, and monitor if the forecasted load growth materializes.
2. **Non-wires Alternatives:** The provincial energy-efficiency initiatives could relieve the future capacity need at Belle River TS and keep the station loading below the station capacity.
3. **Wires Alternatives:** The wire alternatives to this need include upgrading the existing transformers to higher rating units, or transferring some of Belle River TS load to nearby stations through distribution load transfer.

The Study Team recommends Alternative 1, that no further investment is required at this time due to the amount of lead time available. Hydro One and relevant LDCs will continue monitoring the load growth at Belle River TS and re-evaluate the station capacity need in the next planning cycle.

7 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE WINDSOR-ESSEX REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 7-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 7-1: Recommended Plans in Windsor-Essex Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate ($M)
1	Supply capacity need to Kingsville- Leamington area	• Build new switching station at Leamington Junction (Lakeshore TS), and new DESN station (South Middle Road TS) • Build 230 kV double-circuit transmission line from Chatham SS to the new Lakeshore TS	2022-2025	$295M
2	Lauzon TS T5/T6 transformers end-of-life and station capacity	Replace Lauzon TS T5 & T6 transformers replacement with larger 75/125 MVA units	2024	$34M
3	Kent TS station capacity	• Install new feeder positions to supply load growth at Kent TS • Further evaluate plan for the new DESN south of Chatham as part of the Chatham-Lambton-Sarnia regional planning process	-	-
4	Belle River TS station capacity	Monitor load growth and re-evaluate the need in the next regional planning cycle	-	-

The Study Team recommends that Hydro One to continue with the implementation of infrastructure investments listed in Table 7-1 while keeping the Study Team apprised of project status.

8 REFERENCES

[1] **Windsor-Essex Regional Infrastructure Plan (2015)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/RIP%20Report%20Windsor-Essex.pdf

[2] **Windsor-Essex Needs Assessment (2017)**
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs%20Assessment_Windsor-Essex_Final.pdf

[3] **Windsor-Essex Scoping Assessment Outcome Report (2018)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/2018-Windsor-Essex-Scoping-Assessment-Outcome-Report.pdf?la=en

[4] **Windsor-Essex Integrated Regional Resource Plan (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor_Essex_IRRP_Report_20190903.pdf?la=en

[5] **Windsor-Essex Integrated Regional Resource Plan – Appendices (2019)**
http://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor_Essex_IRRP_Appendices_20190903.pdf?la=en

APPENDIX A. STATIONS IN THE WINDSOR-ESSEX REGION

Station (DESN)	Voltage (kV)	Supply Circuits
Keith TS T1	115/27.6	Keith TS 115 kV Bus
Keith TS T22/T23	230/27.6	Keith TS 230 kV Bus
Leamington TS T1/T2	230/27.6	C21J/C22J
Leamington TS T3/T4	230/27.6	C21J/C22J
Malden TS T1/T2	230/27.6	C21J/C22J
Lauzon TS T5/T6	230/27.6	C23Z/C24Z
Lauzon TS T7/T8	230/27.6	C23Z/C24Z
Belle River TS T1/T2	115/27.6	K2Z/K6Z
Kingsville TS T1//T3/T6	115/27.6	K2Z/K6Z
Tilbury West DS	115/27.6	K2Z
Tilbury TS T1	115/27.6	K2Z
Crawford TS T3/T4	115/27.6	J3E/J4E
Essex TS T5/T6	115/27.6	Essex TS 115 kV Bus
Walker TS #1 T3/T4	115/27.6	Z1E/Z7E
Walker MTS #2	115/27.6	Z1E/Z7E
Ford Essex CTS	115/13.8	Z1E/Z7E
Chrysler WAP MTS	115/27.6	E8F/E9F
Ford Annex MTS	115/13.8	E8F/E9F
Ford Windsor MTS	115/27.6	E8F/E9F
G.M. Windsor MTS	115/27.6	E8F/E9F

APPENDIX B. TRANSMISSION LINES IN THE WINDSOR-ESSEX REGION

Location	Circuit Designations	Voltage (kV)
Chatham x Keith	C21J, C22J	230
Chatham x Lauzon	C23Z, C24Z	230
Keith x Essex	J3E, J4E	115
Lauzon x Essex	Z1E, Z7E	115
Essex x East Windsor CGS	E8F, E9F	115
Lauzon x Kingsville	K2Z, K6Z	115
Keith x Michigan Tie	J5D	115

APPENDIX C. DISTRIBUTORS IN THE WINDSOR-ESSEX REGION

Distributor Name	Station Name	Connection Type
E.L.K. Energy Inc.	Belle River TS	Dx
	Kingsville TS	Dx
	Lauzon TS	Dx
Entegrus Powerlines Inc.	Kingsville TS	Dx
	Leamington TS	Dx
	Tilbury West DS	Dx
EnWin Utilities Ltd.	Crawford TS	Tx
	Essex TS	Tx
	Keith TS	Tx
	Lauzon TS	Tx
	Malden TS	Tx
	Walker TS #1	Tx
	Walker MTS #2	Tx
	Chrysler WAP MTS	Tx
	Ford Annex MTS	Tx
	Ford Essex CTS	Tx
	Ford Windsor MTS	Tx
	G.M. Windsor MTS	Tx
Essex Powerlines Corp.	Keith TS	Dx
	Lauzon TS	Dx
	Leamington TS	Dx
	Malden TS	Dx
Hydro One Networks Inc. (Distribution)	Belle River TS	Tx
	Kingsville TS	Tx
	Lauzon TS	Tx
	Tilbury West DS	Tx
	Tilbury TS	Tx
	Keith TS	Tx
	Malden TS	Tx
	Leamington TS	Tx

APPENDIX D. WINDSOR-ESSEX REGION NON-COINCIDENT LOAD FORECAST

Table D-1: Windsor-Essex Non-Coincident (Summer) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Keith TS	142	104	88	87	87	86	86	85	85	85	85	85	85
Lauzon T5/T6	101	124	128	130	131	132	133	134	135	136	138	139	140
Lauzon T7/T8	103	87	88	87	88	88	89	89	89	89	90	90	90
Leamington T3/T4	183	121	120	122	123	123	123	124	125	126	127	127	128
Leamington T1/T2	183	4	68	125	139	139	139	139	140	140	140	144	145
Malden TS	183	134	134	134	135	135	135	134	135	136	137	137	137
115 kV													
Belle River TS	54	47	48	49	49	50	51	52	53	54	55	56	57
Crawford TS	92	81	82	82	83	84	85	86	87	88	88	89	90
Essex TS	107	89	90	90	91	92	93	93	94	95	95	96	97
Industrial Customer #1	59	34	34	35	35	35	35	35	35	35	35	35	35
Industrial Customer #2	39	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer #3	39	10	10	10	10	10	10	10	10	10	10	10	10
Industrial Customer #4	59	16	16	16	16	17	17	17	17	17	17	17	17
Industrial Customer #5	39	24	24	24	24	24	24	25	25	25	25	25	26
Kingsville TS	104	87	86	85	85	85	85	85	84	84	105	92	93
Tilbury TS	7	0	0	0	0	0	0	0	0	0	0	0	0
Tilbury West DS	31	19	19	20	20	20	20	20	20	21	21	21	22
Walker MTS #2	89	115	116	117	118	119	119	120	121	122	123	124	125
Walker TS #1	90	71	72	73	74	74	75	76	77	77	78	79	80

* Station LTR is based on 90% power factor

** Non-coincident station peak, adjusted to extreme weather

Table D-2: Kingsville TS and Leamington TS Non-Coincident (Winter) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Leamington T3/T4	195	109	166	181	181	181	180	180	181	180	181	217	226
Leamington T1/T2	195	3	61	114	127	127	127	127	127	128	128	146	152
115 kV													
Kingsville TS	116	102	116	116	116	116	116	116	116	115	115	128	131

APPENDIX E. WINDSOR-ESSEX REGION COINCIDENT LOAD FORECAST

Table E-1: Windsor-Essex Coincident (Summer) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Keith TS	142	69	59	58	58	58	57	57	57	57	57	57	57
Lauzon T5/T6	101	121	125	126	127	128	129	130	131	133	134	135	136
Lauzon T7/T8	103	84	85	85	85	86	86	86	87	87	87	87	88
Leamington T3/T4	183	121	120	122	123	123	123	124	125	126	127	127	128
Leamington T1/T2	183	4	68	125	139	139	139	139	140	140	140	144	145
Malden TS	183	128	128	128	129	129	129	129	129	130	131	131	131
115 kV													
Belle River TS	54	44	45	46	47	48	49	49	50	51	52	53	54
Crawford TS	92	72	73	74	75	75	76	77	78	78	79	80	81
Essex TS	107	86	86	87	88	88	89	90	90	91	92	93	93
Industrial Customer #1	59	32	33	33	33	33	33	33	33	33	33	33	34
Industrial Customer #2	39	7	7	7	7	7	7	7	7	7	7	7	7
Industrial Customer #3	39	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer #4	59	4	4	4	4	4	4	4	4	4	4	4	4
Industrial Customer #5	39	15	15	15	15	15	15	15	16	16	16	16	16
Kingsville TS	104	82	81	80	80	80	80	80	79	79	99	87	87
Tilbury TS	7	0	0	0	0	0	0	0	0	0	0	0	0
Tilbury West DS	31	18	19	19	19	19	19	19	20	20	20	20	21
Walker MTS #2	89	76	77	77	78	79	79	80	81	81	82	82	83
Walker TS #1	90	61	61	62	62	63	64	64	65	66	66	67	68

* Station LTR is based on 90% power factor

** Coincident station peak, adjusted to extreme weather

Table E-2: Kingsville TS and Leamington TS Coincident (Winter) Net Load Forecast

Station	LTR* (MW)	2019**	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
230 kV													
Leamington T3/T4	195	109	166	181	181	181	180	180	181	180	181	217	226
Leamington T1/T2	195	3	61	114	127	127	127	127	127	128	128	146	152
115 kV													
Kingsville TS	116	87	99	99	99	99	99	99	98	98	98	109	112

APPENDIX H – E.L.K. REG INVESTMENT PLAN

E.L.K. ENERGY INC.

Renewable Energy Generation Investments Plan

Prepared for the

Independent Electricity System Operator

To accompany

E.L.K. Energy Inc.'s
2021 Cost of Service Application

October 25, 2021

TABLE OF CONTENTS

1 INTRODUCTION

E.L.K. Inc. ("**E.L.K.**") is preparing to file a Cost of Service ("**COS**") Application for the prospective rate year of 2022. In accordance with the Ontario Energy Board ("**OEB**") *Filing Requirements for Electricity Transmission and Distribution Applications*, E.L.K. has prepared this Renewable Energy Generation ("**REG**") Investments Plan to accompany its Distribution System Plan ("**DSP**") and COS Application.

This REG Investments Plan provides information on E.L.K.'s ability to accommodate new REG connections to its distribution system. The purpose of this REG Investments Plan is to inform the Independent Electricity System Operator ("**IESO**") of any REG investments over the DSP period (2022-2026) and to request the IESO to provide a letter commenting on this information.

Section 2 of this REG Investments Plan provides background information regarding E.L.K.'s distribution system. Section 3 lists the existing and proposed REG connections. Section 4 contains the system assessment to identify constraints. Finally, Section 5 summarizes the proposed investments to facilitate new REG connections.

2 E.L.K.'S DISTRIBUTION GRID

E.L.K. supplies electrical service to customers within the former municipalities of Belle River, Comber, Cottam, Essex, Harrow and Kingsville. E.L.K. had 12,611 customers as of the end of [2020], including over 11,076 residential customers, with a service territory of 23 sq. km. All of E.L.K.'s service territories are embedded within Hydro One Networks Inc. ("Hydro One"). The map in Figure 1 depicts E.L.K.'s service territory boundaries.

Figure 1: E.L.K.'s Service Territory

E.L.K. owns, maintains and operates approximately 89 km of overhead primary distribution feeders and 79 km of underground primary distribution circuits including seven 27.6 kV feeders and one 8.32kV feeders. Bulk power system supply is provided by four Hydro One owned transformer stations.

3 EXISTING AND PROPOSED CONNECTIONS

There are a total of 168 renewable energy generation installations presently connected to E.L.K.'s distribution system under the province's Feed-in-Tariff ("**FIT**") and micro-FIT programs, as summarized below and detailed in Table 1 and Table 2, respectively. In summary E.L.K. has:

- 8 FIT installations with generating capacity of 2,439.4 kW, listed in Table 1
- 155 micro-FIT installations with 1,365 kW installed capacity, as shown in Table 2
- 5 solar net-metering installations with 45 kW installed capacity.

In addition to the above, there are 2 Net Metering projects in the Applications progress but have not yet proceeded to the development stage. There are currently no other applications in queue waiting for connections.

E.L.K. is providing the last five-year statistics of net-metering services connected to the distribution system in Table 4. Approximately one new net-metering service has been installed each year. Hence, E.L.K. forecasts to connect similar to historical levels of new net-metering service a year over the 2022-2026 forecast periods.

Table 1 – FIT Generation Facilities

IESO ID	Fuel Source	Rating (kW)	Install Date
FIT-F91K2I8	Solar	500	December 20, 2013
FIT-FP9WAYB	Solar	60	May 14, 2014
FIT-F8GRPP8	Solar	250	June 14, 2014
FIT-F9R9C4R	Solar	449.4	November 8, 2014
FIT-GD5BY12	Solar	470	March 25, 2015
FIT-GZRFYSL	Solar	150	December 21, 2016
FIT-G1DEKZD	Solar	190	December 21, 2016
FIT-GHPXEHM	Solar	370	March 16, 2017

Table 2 – MicroFIT Generation Facilities

Micro-FIT Reference #	Meter Install Date	Rating (kW)
FIT-MGNMCW8	10-SEP-10	10
FIT-MEIFTIN	17-DEC-10	10
FIT-MV8KW2V	17-DEC-10	10
FIT-MQRIXCE	27-AUG-10	9.5
FIT-MJD8D8A	08-DEC-11	4.56
FIT-MBDWVHX	08-SEP-11	3.04
FIT-MXKNQ3U	10-MAY-11	10
FIT-MYBD6D6	14-DEC-11	4.56
FIT-MGGUBEZ	15-NOV-11	7.41
FIT-M8TPEQD	16-AUG-11	9.8
FIT-M88UKQK	16-AUG-11	9.8
FIT-MBMDHK3	16-AUG-11	9.8

FIT-MBX9D4A	16-AUG-11	9.8
FIT-MD4VKQ2	16-AUG-11	9.8
FIT-MG8TFKI	16-AUG-11	9.8
FIT-MU9NBJ4	16-AUG-11	9.8
FIT-MVUCYF6	16-AUG-11	9.8
FIT-MW9FZ4C	16-AUG-11	9.8
FIT-MXJUFXM	16-AUG-11	9.8
FIT-MYJCYQV	16-AUG-11	9.8
FIT-M3CPXNP	17-AUG-11	9.8
FIT-M6XUG32	17-AUG-11	9.8
FIT-M8H8E93	17-AUG-11	9.8
FIT-MB49WPZ	17-AUG-11	9.8
FIT-MFQEJIT	17-AUG-11	9.8
FIT-MFUZBYE	17-AUG-11	9.8
FIT-MGGNNG6	17-AUG-11	9.8
FIT-MHRD7KD	17-AUG-11	9.8
FIT-MKKRAR9	17-AUG-11	9.8
FIT-MKNMI4B	17-AUG-11	9.8
FIT-MMPT3AB	17-AUG-11	9.8
FIT-MMZVA3A	17-AUG-11	9.8
FIT-MRHE3MZ	17-AUG-11	9.8
FIT-MT7W6TP	17-AUG-11	9.8
FIT-MTZXK7J	17-AUG-11	9.8
FIT-MYQ2PGJ	17-AUG-11	9.8
FIT-MZXPDH6	17-AUG-11	9.8
FIT-MFCQKW8	18-NOV-11	5.7
FIT-M6T28R8	22-JUL-11	9.8
FIT-M9V6I4T	22-JUL-11	9.8
FIT-MAATKP3	22-JUL-11	9.8
FIT-MANIHRM	22-JUL-11	9.8
FIT-MCR2IA4	22-JUL-11	9.8
FIT-MDJBDY3	22-JUL-11	9.8
FIT-MFVH3NR	22-JUL-11	9.8
FIT-MHX2NGK	22-JUL-11	9.8
FIT-MIAZ4JM	22-JUL-11	9.8
FIT-MK6FFZG	22-JUL-11	9.8
FIT-MMWRU3W	22-JUL-11	9.8
FIT-MNH3HDW	22-JUL-11	9.8
FIT-MTVPYEP	22-JUL-11	9.8
FIT-MURHQRN	22-JUL-11	9.8
FIT-MUT2KFV	22-JUL-11	9.8
FIT-MK7YAER	19-JAN-11	5
FIT-MF9WIPQ	19-SEP-11	5.7

FIT-M8BQR7Z	22-SEP-11	4.94
FIT-MQ4KDTT	22-SEP-11	9.89
FIT-M6DC72H	24-NOV-11	4.18
FIT-MAVHZGK	28-NOV-11	10
FIT-MH2KN2R	31-AUG-11	9.8
FIT-MGH9P4A	04-APR-12	6.65
FIT-MTVNF7H	04-APR-12	3.04
FIT-M3M6U3U	05-JUL-12	9.6
FIT-M4Z2PDN	05-JUL-12	9.6
FIT-M6V66QZ	05-JUL-12	7.095
FIT-M8B3B3P	05-JUL-12	9.6
FIT-M8DUG29	05-JUL-12	9.6
FIT-M9AMXQK	05-JUL-12	7.74
FIT-M483RIV	05-JUL-12	9.6
FIT-MAGWVJW	05-JUL-12	9.6
FIT-MBZXG6M	05-JUL-12	9.6
FIT-MED4M9K	05-JUL-12	9.6
FIT-MENEQGT	05-JUL-12	9.6
FIT-MGFWYXV	05-JUL-12	9.6
FIT-MI7XQWZ	05-JUL-12	9.6
FIT-MKNNBC4	05-JUL-12	9.6
FIT-MMMM38M	05-JUL-12	9.6
FIT-MNG39R7	05-JUL-12	6.88
FIT-MNJBHJH	05-JUL-12	9.6
FIT-MT8JCUB	05-JUL-12	9.6
FIT-MUT4AIC	05-JUL-12	9.6
FIT-MUZNCDD	05-JUL-12	9.6
FIT-MW8DAQJ	05-JUL-12	9.6
FIT-MWCYQ73	05-JUL-12	9.6
FIT-MWIM9FH	05-JUL-12	9.6
FIT-MXHMB3J	05-JUL-12	9.6
FIT-MXMU7V4	05-JUL-12	9.6
FIT-MYCBYEP	05-JUL-12	9.6
FIT-MVFA66D	06-JUL-12	9.89
FIT-MQ8T2VE	09-JUL-12	6.235
FIT-MZHP6QK	10-APR-12	0.245
FIT-MFI7FIH	11-DEC-12	10
FIT-M8JIWEX	13-NOV-12	6.88
FIT-MZA2938	13-SEP-12	10
FIT-M7DMRQ7	17-OCT-12	10
FIT-M7MEMMP	17-OCT-12	10
FIT-M96F4FM	17-OCT-12	10
FIT-M872GZX	17-OCT-12	10

FIT-MDFIZ2W	17-OCT-12	10
FIT-MK37NPE	17-OCT-12	10
FIT-MM4PB2J	17-OCT-12	10
FIT-MR33IHU	17-OCT-12	10
FIT-MJRNRGN	22-JUN-12	10
FIT-M3B7J9Y	31-JUL-12	6.45
FIT-M8U8RI2	29-FEB-12	5.32
FIT-M8T73H6	16-APR-13	10
FIT-M4G77EX	08-AUG-13	10
FIT-MZ77V6B	08-FEB-13	8.6
FIT-MJBWIQU	08-JAN-13	7.74
FIT-MFHPUIP	08-MAR-13	7.74
FIT-MGIQMCE	10-APR-13	10
FIT-MI9BNP6	10-APR-13	10
FIT-MKQHBIB	10-DEC-13	10
FIT-MJUAVER	12-JUL-13	0.25
FIT-MIXE4TF	13-JUN-13	8.17
FIT-ME7X89A	14-MAY-13	0.235
FIT-MBBN4XV	18-JUN-13	7.505
FIT-MIJJKCB	15-MAY-13	8.6
FIT-MBMHKWB	22-MAR-13	5.16
FIT-MKQVXQE	24-MAY-13	8.6
FIT-MFWZBKV	25-APR-13	9.6
FIT-MBFZMVI	25-MAR-13	8.6
FIT-MFA26DQ	26-SEP-13	5.805
FIT-MHFYKBH	28-NOV-13	0.25
FIT-MFP9WRQ	04-NOV-14	5.8
FIT-MVK8KUC	10-JAN-14	8.6
FIT-MNZ9UDH	11-JUN-14	10
FIT-MIQU9J2	14-AUG-14	6
FIT-MRVJ28P	14-FEB-14	8.6
FIT-MMVTCR9	19-DEC-14	10
FIT-MYAYIBI	28-MAY-14	10
FIT-M836C6J	20-JUL-15	10
FIT-MTWDWAA	21-OCT-15	9.5
FIT-MPWXVV4	05-NOV-15	9.945
FIT-M27MAF6	16-OCT-15	9.945
FIT-MHFBRI2	10-JUN-15	7.6
FIT-MBFB2JM	13-OCT-15	9.5
FIT-ME6BT77	23-NOV-15	9.945
FIT-MPFB44I	23-OCT-15	9.945
FIT-M7GAHE4	25-OCT-16	9.54
FIT-MFHIQQT	26-FEB-16	8.6

FIT-MQ9I2RM	17-FEB-16	9.5
FIT-MJHHPJA	13-JAN-16	8.6
FIT-MRI9CAH	06-JAN-17	9.805
FIT-MXIUPFK	08-NOV-17	9.805
FIT-M8FE7BH	11-JUL-17	9.945
FIT-MQVAZTK	12-MAY-17	9.945
FIT-MXI4NBI	13-JAN-17	9.8
FIT-MA29IJK	18-DEC-17	9.75
FIT-MF4IA3J	25-SEP-17	9.88
FIT-MBPC7GQ	28-APR-17	9.945
FIT-M3KAJHB	29-MAY-17	9.945
FIT-MDX4NM6	26-MAR-18	9.9
FIT-MA2XJR3	16-MAR-18	9.9
FIT-M87FZDA	01-MAY-18	5

Table 3 –Connections for Services over the Historical Period (2017-2021)

Service	**2017**	**2018**	**2019**	**2020**	**2021**
	Count (#)	**Count (#)**	**Count (#)**	**Count (#)**	**Count (#)**
MicroFIT	9	3	0	0	0
FIT	1	0	0	0	0
RESOP	0	0	0	0	0
Net Metering - Solar	0	1	1	1	0

4 SYSTEM ASSESSMENT TO IDENTIFY CONSTRAINTS

E.L.K. has system capacity and will be able to accommodate the REG connections within the five-year planning period. However, there may be limitations with respect to the transmission and distribution stations owned by Hydro One. E.L.K. Energy will continue to offer microFIT connections until formally notified otherwise by Hydro One. FIT connections are subject to impact assessments which will identify any issues prior to an offer to connect. E.L.K. Energy Inc. has established limits for the amount of generation on each of its seven 27.6kV M class feeders and two 8.13kV F class feeders. These capacities are based on 10% and 7% respectively of the feeders peak load. The Peak Load and Available Generation Capacity are noted in Table 4 below:

Table 4: Station and Feeder Capacity

Station	Feeder	Voltage (kV)	Peak Load (kW)	Capacity Allowance (%)	Generation Capacity (kW)	Existing Generation (kW)	Available Generation Capacity (kW)
Belle River TS	M4	27.6	8624	10	8376	641.66	7734.34
Haycroft DS	F3	8.13	1779	7	1101	95	1006
Kingsville TS	M1	27.6	15354	10	1646	77.41	1568.59
Kingsville TS	M5	27.6	16768	10	232	218.03	13.97
Kingsville TS	M7	27.6	10201	10	6799	10	6789
Kingsville TS	M10	27.6	8902	10	8098	247	7851
Lauzon TS	M24	27.6	16541	10	459	47.58	411.42
Lauzon TS	M29	27.6	13401	10	3599	73.33	3525.67

5 Proposed Investments to Facilitate New Connections

E.L.K. currently has no planned connections.

APPENDIX I – IESO REG COMMENT LETTER

IESO response to E.L.K Energy Inc.'s REG Investments Plan 2022 – 2026

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On October 26, 2021, E.L.K. Energy Inc. (E.L.K.) sent its REG Investments Plan to the IESO for comment. The IESO has reviewed E.L.K.'s REG Investments Plan and notes that it contains no investments specific to connecting REG for the plan period 2022 - 2026.

The IESO notes that E.L.K.'s service territory is within the Windsor-Essex planning region. The IESO confirms that E.L.K. participated with the Study Team of this region.[1] The IESO reports that regional planning is complete in the Windsor-Essex region, with the publication of the Integrated Regional Resource Plan (IRRP) on September 3, 2019.[2] An addendum study is underway, with completion anticipated for Q4 2021/Q1 2022.

For the Windsor-Essex Region, Hydro One Networks Inc. published the second cycle Needs Assessment on October 24, 2017, in which the Study Team recommended that an Integrated Regional Resource Plan (IRRP) be undertaken in order to assess the needs identified in the area.[3] The IESO followed with the publication of its Scoping Assessment[4].

E.L.K.'s REG Investments Plan Section 5: Proposed Investments to Facilitate New Connections states:

> "E.L.K. currently has no planned connections."

The IESO submits that as E.L.K. has no REG investments planned at this time nor forecast during the 5-year Distribution System Plan period, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties.[5]

The IESO appreciates the opportunity provided to review the REG Investments Plan of E.L.K. Energy Inc. and looks forward to working together during future regional planning processes.

[1] Windsor-Essex Region Study Team members include the IESO and Hydro One Networks Inc. (Distribution and Lead Transmitter), E.L.K. Energy Inc., Entegrus Powerlines Inc., ENWIN Utilities Ltd. and Essex Powerlines Corporation Inc.

[2] IESO, Windsor-Essex Region IRRP, September 3, 2019: Windsor-Essex (ieso.ca)

[3] Hydro One Networks Inc., Windsor-Essex Needs Assessment, October 24, 2017: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs%20Assessment_Windsor-Essex_Final.pdf

[4] IESO, Windsor-Essex Scoping Assessment Outcome Report, March 2, 2018: Windsor-Essex (ieso.ca)

[5] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

APPENDIX J - E.L.K.'S SERVICE TERRITORY

5.0 CAPITALIZATION POLICY

5.1 CAPITALIZATION POLICY OVERVIEW

Items of property, plant and equipment ("**PP&E**") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date, less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes contracted services, materials and transportation costs, direct labour, overhead costs, borrowing costs and any other costs directly attributable to bringing the asset to a working condition for its intended use.

IFRS requires that borrowing costs related to the construction of the qualifying assets be capitalized. The corporation has applied IAS 23 to all qualifying assets that were in progress or commenced since January 1, 2014. No qualifying assets were identified and therefore no borrowing costs were capitalized for the year ended December 31, 2014.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Corporation and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

The estimated useful lives are as follows:

	Years
Buildings	50
Distribution and metering equipment	10 - 60
Other assets	5 - 15

Impairment

Financial assets measured at amortized cost

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss is calculated as the difference between an asset's carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount. Losses are recognized in profit or loss. An impairment loss is reversed through profit or loss if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

Non-financial assets

The carrying amounts of the Corporation's non-financial assets, other than materials and supplies and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "**cash-generating unit**" or "**CGU**"). The recoverable amount of an asset or CGU is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

For other assets, an impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation or amortization, if no impairment loss had been recognized.

Capitalization by Component

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of property, plant and equipment. Component costs must be significant in relation to the total cost of the item and depreciated separately over the component's useful life. Components are those which: a) are significant in relation to the total cost of the item and b) have different depreciation methods or useful life.

Components with similar useful lives and depreciation methods are grouped in determining the depreciation charge. Parts of the item that are not individually significant (remainder of the items) are combined and categorized as a single component best suited for the sum of the parts.

Depreciation

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

E.L.K. has used the Typical Useful Life provided in the Kinectrics Report as its basis for assigning the estimated service life to assets. Depreciation of an asset begins in the year when it is available for use, i.e. when it is in the location and condition necessary for it to be capable of operating in the manner intended. For rate setting purposes, in the first year of service, depreciation is calculated using the ½ year rule. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated.

Overhead Policy

E.L.K.'s overhead policy has been reviewed by its external auditors and has been deemed IFRS compliant.

E.L.K. does not capitalize general administrative costs related to Administration, HR or Finance.

Payroll burden consists of the following benefits paid to employees: health benefits, prescription drugs, dental vision, long-term disability, bereavement time, OMERS, Workplace Safety and Insurance Board, Employment insurance, CPP, EHT and E.L.K. employees' protection equipment (safety shoes/ clothing/expendable tools). IAS 16 specifically allows for benefits as defined in IAS 19 to be included as a directly attributable cost. The payroll allocation is allocated to capital based upon labour dollars charged to capital. Benefits are accumulated in the general ledger for all employees and allocated based upon where the employees charge their time (capital jobs/maintenance).

6.0 CAPITALIZATION OF OVERHEAD

6.1 OVERVIEW

E.L.K., along with its consultant KPMG, performed an analysis of all costs that were being capitalized under CGAAP in order to determine whether these costs were eligible for capitalization under IFRS. As discussed above in the "Capitalization Policy Overview" section, it was determined that no changes were required to the capitalization of overhead as a result of the transition to IFRS and that the policy as explained above is compliant with IFRS requirements.

6.2 BURDEN RATES

Standard: IAS 16 – Property, Plant and Equipment

Topic: Capitalization - Overheads

Objective:

To document the accounting policy for the capitalization of overheads.

Background:

<u>Core Principle</u>

The cost of an item of property, plant and equipment (PP&E) is recognized as an asset if and only if:

a) It is probable that future economic benefits will flow to the company; and
b) The cost of the item can be measured reliably.

The cost of an item of PP&E includes any costs that are directly attributable to bringing the asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

Certain costs are explicitly prohibited from inclusion as costs of an item of PP&E:

a) Costs of opening a new facility;
b) Costs of introducing a new product or service (including advertising and promotion);
c) Costs of conducting business in a new location or with a new class of customer (including costs of staff training)

d) Administration and other general overhead costs; and,
e) Day-to-day servicing costs.

IAS 16 does not indicate what constitutes an item of PP&E. Judgment is required when applying the core principle.

Directly attributable

The term "directly attributable" is not defined in IAS 16. The specific facts and circumstances surrounding the cost and the ability to demonstrate that the cost is directly attributable to an item of PP&E is critical to establishing whether the cost should be capitalized. The cost must be attributed to a specific item of PP&E at the time it is incurred. The incurrence of that cost should aid directly in the construction effort making the asset more capable of being used than if the cost had not been incurred.

General and administrative overhead

IFRS does not provide a definition of general and administrative overhead (G&A). The specific facts and circumstances surrounding the nature of the costs and the activity associated with it must be considered to determine if it is directly attributable to an item of PP&E.

G&A costs typically benefit the organization as a whole or areas of the organization more broadly rather than contributing directly to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management. The more the nature of a particular cost strays from being directly attributable to an item of PP&E, then the more likely it is that the cost will be determined to be in the nature of G&A.

Day-to-day servicing costs

Day-to-day servicing costs are defined as costs of labour and consumables and may include the cost of small parts. The purpose of these expenditures is often described as for the "repairs and maintenance" of the item of PP&E.

Whether to capitalize repairs and maintenance (R&M) is dependent on the interpretation of paragraph IAS 16.12.

Interpretations:

1. Interpret wording in paragraph 12 to mean “that under no circumstances do R&M get capitalized”. Example – Capitalizing the cost of a repair to the value of the vehicle, this is *not* permitted under IFRS
2. Interpret wording in paragraph 12 to mean that R&M costs do not get capitalized to the cost of the item of PP&E that has been repaired but the repair cost becomes part of the operating cost of an item of PP&E that is used to construct another item of PP&E. The operating costs are then capitalized to the constructed item of PP&E. This is permitted under IFRS since the cost is directly attributable to bringing a physical asset to the location and condition necessary for it to be capable of operating in the manner intended by management.

<u>Feasibility studies and pre-construction activities</u>

Normally, feasibility studies are not capitalized under IFRS as these costs do not always result in asset construction, and therefore may not meet the criteria of providing a future economic benefit. Additionally, the associated costs must be directly attributable to an item of PP&E. Pre-construction activities (such as design work) prior to a decision to go ahead with a capital project do not qualify for capitalization.

Considerations:

Canadian GAAP allowed for capitalization of general and administrative overhead, training costs, etc. while IFRS does not.

The Ontario Energy Board (OEB) requires electricity distributors to be in full compliance with IFRS requirements as applicable to non-regulated enterprises and only where the Board authorizes specific alternative treatment for regulatory purposes is alternative treatment acceptable.

E.L.K. performed a complete review of its costs included in overheads.

The analysis that follows is based upon the overheads that have historically been included for capitalization.

Payroll burden

Payroll burden consists of the following benefits paid to employees: health benefits, prescription drugs, dental vision, long-term disability, bereavement time, OMERS, Workplace Safety and Insurance Board, Employment insurance, CPP, EHT and E.L.K. employees' protection equipment (safety shoes/ clothing/expendable tools). IAS 16 specifically allows for benefits as defined in IAS 19 to be included as a directly attributable cost. The payroll allocation is allocated to capital based upon labour dollars charged to capital. Benefits are accumulated in the general ledger for all employees and allocated based upon where the employees charge their time (capital jobs/maintenance).

Truck burden

Truck burden consists of fuel, vehicle maintenance, repairs and license renewals. Trucks and company vehicles are used on the job site and are directly related to the construction of an asset as they are required to construct the asset. Truck expenses are allocated to capital based upon the timesheets recorded for the truck.

Fuel, amortization related to the truck, truck insurance and license renewals can be capitalized because they are costs required to keep the trucks in running order and are directly attributable to constructing the asset and bringing it to its intended use. Amortization is not currently included in the truck allocation under CGAAP.

E.L.K. is taking the position that repairs and maintenance costs are operating costs of the trucks and therefore can be capitalized since they are directly attributable costs meeting IFRS criteria.

Stores costs

Currently, a stores overhead is not applied to inventory used on capital jobs.

Under IFRS, general and administrative expenses are not capitalized. General and administrative expenses tend to benefit the organization as a whole rather than a single job (or item of PPE).

Typically, maintaining stores are more efficient than having parts delivered direct to the job site as they are needed. This fact indicates that stores costs are more in the nature of general and administrative overhead and are not capitalized.

Engineering costs

Currently, an engineering burden is not applied to capital jobs, since all E.L.K. employees complete timesheets and charge time spent on capital jobs directly to the job.

Conclusion:

E.L.K. will capitalize all costs, including the above overheads, when the cost is directly attributable to bringing the item of PP&E to the location and condition necessary for it to be capable of operating in the manner intended by management.

Any general and administrative costs that have not been discussed above will not be capitalized.

The following changes were made to the capitalization policy as a result of the transition to IFRS:

Payroll burden:

No changes were identified for this burden.

Truck burden:

Amortization of the vehicles should form part of the truck burden. Since the amortization is not significant, the portion allocated to capital would also be insignificant, no change to the burden will be made.

Engineering burden:

No changes were identified for this burden.

Stores burden:

No changes were identified for this burden.

6.3 COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

E.L.K. has incurred costs for the connection of qualifying generation facilities of $176,493 as outlined Exhibit 9, this amount was recorded in account 1531- Renewable Generation Connection Capital Deferral Account. This balance will be incorporated into rate base as part of the update of this application for year-end 2021 actual results. It is expected that this will take place during the interrogatory phase of this proceeding.

6.4 NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

On September 18, 2014, the Board released Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module and in it the Board has established the following mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing:

> The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("**ICM**"), this new mechanism will be named the Advanced Capital Module (or "**ACM**").

> Advancing the reviews of eligible discrete capital projects, included as part of a distributor's Distribution System Plan and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the Board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

E.L.K. does not have any discrete capital projects within the five-year horizon that it believes would require this new policy option. The capital investment required by E.L.K. from 2022 through 2026 is relatively flat and E.L.K. believes it can be managed through the rates proposed within this application.

6.5 ADDITION OF ICM ASSETS TO RATE BASE

E.L.K. has not applied for approval of ICM Assets and therefore has no such assets added to its rate base.

7.0 SERVICE QUALITY AND RELIABILITY PERFORMANCE

7.1 SERVICE QUALITY AND RELIABILITY PERFORMANCE MEASURES

E.L.K. records and reports annually the following Service Reliability Indices:

- SAIDI = Total Customer-Hours of Interruptions/Total Customers Served
- SAIFI = Total Customer Interruptions/Total Customers Served
- CAIDI = Total Customer-Hours of Interruptions/Total Customer Interruptions

These indices provide E.L.K. with annual measures of its service performance that are used for internal benchmarking purposes when making comparisons with other distribution companies (e.g. to better understand the rankings that will support the OEB's Incentive Rate Making Mechanism and Performance Based Regulation). They are reported below in accordance with Section 7.3.2 of the OEB's Electricity Distribution Rate Handbook.

E.L.K. follows the Board's Reporting and Record Keeping Requirements Guideline to report its service quality indicators annually. In accordance with the Filing Requirements, Table 2-26 is provided below and is consistent with Board Appendix 2-G, Service Quality Indicators. The table provides the performance measurements for the last five (5) historical years – 2016 through 2020.

E.L.K.'s performance results over the 2016 to 2020 period meet or exceed the Board's approved standards. E.L.K.'s performance is within the range of acceptable performance over the previous five years and no corrective action is required.

Table 2-26 – Service Quality and Reliability Performance

Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Including outages caused by loss of supply					Excluding outages caused by loss of supply					Excluding Major Event Days				
	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020	2016	2017	2018	2019	2020
SAIDI	0.422	0.630	2.949	2.656	5.448	0.250	0.630	1.627	1.848	3.343	0.422	0.630	2.949	2.656	5.448
SAIFI	0.173	0.205	1.130	1.313	2.171	0.087	0.205	0.482	0.722	1.146	0.173	0.205	1.130	1.313	2.171

5 Year Historical Average

	Including outages caused by loss of supply	Excluding outages caused by loss of supply	Excluding Major Event Days
SAIDI	2.421	1.540	2.421
SAIFI	0.999	0.528	0.999

SAIDI = System Average Interruption Duration Index
SAIFI = System Average Interruption Frequency Index

Service Quality

Indicator	OEB Minimum Standard	2016	2017	2018	2019	2020
Low Voltage Connections	90.0%	93.9%	94.4%	99.0%	99.3%	99.5%
High Voltage Connections	90.0%	0.0%	100.0%	100.0%	0.0%	0.0%
Telephone Accessibility	65.0%	97.2%	96.6%	96.3%	97.7%	95.1%
Appointments Met	90.0%	98.9%	98.6%	100.0%	100.0%	99.1%
Written Response to Enquires	80.0%	97.9%	98.9%	99.2%	98.0%	98.7%
Emergency Urban Response	80.0%	100.0%	88.9%	100.0%	100.0%	100.0%
Emergency Rural Response	80.0%	0.0%	100.0%	100.0%	100.0%	0.0%
Telephone Call Abandon Rate	10.0%	0.1%	0.1%	0.2%	0.3%	0.3%
Appointment Scheduling	90.0%	96.3%	98.7%	98.7%	98.9%	99.1%
Rescheduling a Missed Appointment	100.0%	100.0%	100.0%	100.0%	0.0%	0.0%
Reconnection Performance Standard	85.0%	100.0%	100.0%	93.9%	100.0%	100.0%