EXHIBIT 2 – RATE BASE AND CAPITAL

2024 Cost of Service

Orangeville Hydro Limited

EB-2023-0045

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2.0 RATE BASE AND CAPITAL

2.1 RATE BASE

2.1.1 RATE BASE BASIS

Orangeville Hydro Limited's ("OHL") Rate Base is determined by taking the average of the net in-service fixed asset balances at the beginning and end of the Test Year, plus a working capital allowance, which is 7.5% of the sum of the cost of power and recoverable/controllable expenses. The use of a 7.5% rate is consistent with the Board's letter of October 20, 2022, and the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications as issued by the Ontario Energy Board on December 15, 2022. OHL 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%. OHL was not previously directly by the OEB to undertake a lead/lag study.

OHL's 2024 Cost of Service ("CoS") Rate Application has been filed in accordance with Modified International Financial Reporting Standards ("MIFRS"). OHL converted to MIFRS in 2015 and has not rebased since. The change to MIFRS was done retroactively to January 1, 2014. There was no difference between CGAAP and MIFRS to OM&A balances and net book value of fixed assets. A reconciliation between CGAAP and MIFRS has been provided further in this Exhibit. All schedules and number references in this application are in accordance with MIFRS unless otherwise noted.

As detailed in the table below, there is no MIFRS transition impact to rate base and base revenue requirement.

Table 2-1 - OEB Appendix 2-Y Impact to Rate Base

Appendix 2-Y
Summary of Impacts to Revenue Requirement
from Transition to MIFRS

Revenue Requirement Component	2024 MIFRS	2024 CGAAP [1]	Difference	Reasons why the revenue requirement component is different under MIFRS
Closing NBV 2023	$ 23,340,703	$ 23,340,703	$ -	
Closing NBV 2024	$ 25,121,954	$ 25,121,954	$ -	
Average NBV	$ 24,231,328	$ 24,231,328	$ -	
Working Capital	$ 2,511,255	$ 2,511,255	$ -	
Rate Base	$ 26,742,584	$ 26,742,584	$ -	
Return on Rate Base	$ 1,733,078	$ 1,733,078	$ -	
			$ -	
OM&A	$ 4,235,523	$ 4,235,523	$ -	
Depreciation	$ 1,124,239	$ 1,124,239	$ -	
PILs or Income Taxes	$ 184,067	$ 184,067	$ -	
Property Tax	$ 44,298	$ 44,298	$ -	
Less: Revenue Offsets	-$ 402,186	-$ 402,186	$ -	
			$ -	
			$ -	
			$ -	
Insert description of additional item(s)			$ -	
Total Base Revenue Requirement	$ 6,919,019	$ 6,919,019	$ -	No material differences noted between MIFRS and CGAAP that would cau

OHL attests that capital expenditures in rate base are equivalent to in-service additions. The 2023 Bridge and 2024 Test years do not have any work-in-progress.

The net fixed assets include solely those distribution assets associated with activities that enable the conveyance of electricity for distribution purposes. OHL owns solar panels which are non-distribution assets and therefore, are not included in the rate base.

Eligible recoverable/controllable expenses used in the calculation of the working capital allowance ("WCA") include operations and maintenance, billing and collecting, community relations, administration expenses, eligible LEAP donations and taxes other than PILs consistent with OEB guidance.

For rate base, OHL has included the opening and closing balances for each year, and the average of the opening and closing balances for gross fixed assets and accumulated depreciation.

Note that the gross fixed assets and accumulated depreciation balances used correspond directly to the Fixed Asset Continuity Schedules that can be found within this document in 2.2.1 Continuity Statements and also in excel format in Chapter 2 Appendix 2-BA Fixed Asset Continuity.

Capital expenditures do vary from in-service additions for historical years and work-in-progress items have been clearly identified in any variance explanations for the 2022 bridge year and in the 2023 test year, capital expenditures are assumed to equal in-service additions.

This exhibit will compare historical data with the 2023 Bridge Year and 2024 Test Year. OHL converted to MIFRS on January 1, 2015, and has prepared this application under MIFRS. In order to make the comparisons meaningful, all comparisons will be made under MIFRS.

OHL has calculated its 2024 Test Year rate base to be $26,742,584. This rate base is also used to determine the proposed revenue requirement found in Exhibit 6.

Table 2-2 below presents OHL's Rate Base calculations for the Test Year.

Table 2-2 – 2024 Test Year vs 2014 OEB Approved Rate Base

Working Capital Allowance	2024 Test MIFRS	2014 Board Approved	Variance	% Variance
Recoverable OM&A Expenses	4,235,523	3,255,183	980,340	30%
Taxes Other than Income Taxes	44,298		44,298	0%
Less Allocated Depreciation in OM&A	(95,304)	(60,470)	(34,834)	58%
Total Eligible Distribution Expenses	**4,184,517**	**3,194,713**	**989,804**	**31%**
Power Supply Expenses	29,298,887	27,763,022	1,535,865	6%
Total Working Capital Expenses	**33,483,404**	**30,957,735**	**2,525,669**	**8%**
Working Capital Factor	7.5%	10.0%	-2.5%	-25%
Working Capital Allowance	**$2,511,255**	**$3,095,774**	**($584,518)**	**-19%**
Rate Base Calculation	**2024 Test MIFRS**	**2014 Board Approved**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	23,340,703	15,800,862	7,539,841	48%
Ending Balance	25,121,954	16,639,780	8,482,174	51%
Average Balance	**24,231,328**	**16,220,321**	**8,011,007**	**49%**
Working Capital Allowance	2,511,255	3,095,774	(584,518)	-19%
Total Rate Base	**$26,742,584**	**$19,316,095**	**$7,426,489**	**38%**

The variance between the 2024 Test Year and the 2014 OEB Approved amounts is largely due to an increase in the average net fixed assets of $8.0M as a result of capital additions over the 10-year 2014-2023 period. This is offset by a $0.6M reduction in WCA, mostly due to the change from 10% to 7.5% and the reduction in power supply expense due to the Ontario Electricity Rebate ("OER") of 11.7% in 2024. OHL has invested in its distribution system since the last CoS application, at a measured pace over a period of 10 years. Further details of OHL's fixed asset additions over the 10-year period can be found in section

2.2.4 Asset Variance Analysis by OEB Category.

2.1.2 RATE BASE TREND

The table below presents OHL's Rate Base calculations for all required years including the 2024 Test Year.

OHL started using account 6105 Taxes Other than Income Taxes in 2018. For the years 2014 to 2017, property taxes were included in Recoverable OM&A Expenses.

Year over year variance analysis of capital additions follows in section

2.2.4 Asset Variance Analysis by OEB Category. Year over year analysis of Recoverable OM&A expenses can be found in Exhibit 4, section 4.2.1.

Table 2-3 - Rate Base Trend 2014 OEB Approved to 2018 Actuals

Working Capital Allowance	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS
Recoverable OM&A Expenses	3,255,183	3,224,934	3,287,582	3,317,207	3,323,900	3,200,271
Taxes Other than Income Taxes		-	-	-	-	14,349
Less Allocated Depreciation in OM&A	(60,470)	(53,409)	(68,841)	(78,947)	(83,833)	(89,283)
Total Eligible Distribution Expenses	**3,194,713**	**3,171,524**	**3,218,741**	**3,238,260**	**3,240,067**	**3,125,336**
Power Supply Expenses	27,763,022	26,967,661	29,745,385	33,273,556	29,609,584	27,833,754
Total Working Capital Expenses	**30,957,735**	**30,139,185**	**32,964,126**	**36,511,816**	**32,849,651**	**30,959,090**
Working Capital Factor	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%
Working Capital Allowance	**$3,095,774**	**$3,013,919**	**$3,296,413**	**$3,651,182**	**$3,284,965**	**$3,095,909**

Rate Base Calculation	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS
Net Capital Assets in Service						
Opening Balance	15,800,862	15,695,180	16,391,075	16,467,536	17,131,085	18,083,203
Ending Balance	16,639,780	16,391,075	16,467,536	17,131,085	18,083,203	18,691,380
Average Balance	**16,220,321**	**16,043,128**	**16,429,305**	**16,799,310**	**17,607,144**	**18,387,292**
Working Capital Allowance	3,095,774	3,013,919	3,296,413	3,651,182	3,284,965	3,095,909
Total Rate Base	**$19,316,095**	**$19,057,046**	**$19,725,718**	**$20,450,492**	**$20,892,109**	**$21,483,201**
Actuals Year Over Year Variance $			**$ 668,672**	**$ 724,774**	**$ 441,617**	**$ 591,091**
Total Rate Base Growth (from 2014 Board Approved						
Actuals Year over Year Variance %			**3.5%**	**3.7%**	**2.2%**	**2.8%**
Compound Annual Growth Rate (from 2014 Board Approved)						

Table 2-4 - Rate Base Trend 2019 Actuals to 2024 Test Year

Working Capital Allowance	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Recoverable OM&A Expenses	3,442,073	3,197,840	3,380,858	3,639,401	3,812,695	4,235,523
Taxes Other than Income Taxes	36,763	41,103	41,256	41,686	43,008	44,298
Less Allocated Depreciation in OM&A	(94,914)	(96,653)	(98,795)	(99,368)	(97,851)	(95,304)
Total Eligible Distribution Expenses	**3,383,923**	**3,142,290**	**3,323,319**	**3,581,719**	**3,757,853**	**4,184,517**
Power Supply Expenses	29,083,782	32,771,802	29,029,339	30,671,964	29,356,772	29,298,887
Total Working Capital Expenses	**32,467,705**	**35,914,093**	**32,352,657**	**34,253,683**	**33,114,624**	**33,483,404**
Working Capital Factor	10.0%	10.0%	10.0%	10.0%	10.0%	7.5%
Working Capital Allowance	**$3,246,770**	**$3,591,409**	**$3,235,266**	**$3,425,368**	**$3,311,462**	**$2,511,255**

Rate Base Calculation	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Net Capital Assets in Service						
Opening Balance	18,691,380	19,017,648	19,676,331	20,535,536	22,392,450	23,340,703
Ending Balance	19,017,648	19,676,331	20,535,536	22,392,450	23,340,703	25,121,954
Average Balance	**18,854,514**	**19,346,989**	**20,105,933**	**21,463,993**	**22,866,577**	**24,231,328**
Working Capital Allowance	3,246,770	3,591,409	3,235,266	3,425,368	3,311,462	2,511,255
Total Rate Base	**$22,101,285**	**$22,938,398**	**$23,341,199**	**$24,889,362**	**$26,178,039**	**$26,742,584**
Actuals Year Over Year Variance $	**$ 618,084**	**$ 837,114**	**$ 402,801**	**$ 1,548,162**	**$ 1,288,677**	**$ 564,545**
Total Rate Base Growth (from 2014 Board Approved						**38%**
Actuals Year over Year Variance %	**2.9%**	**3.8%**	**1.8%**	**6.6%**	**5.2%**	**2.2%**
Compound Annual Growth Rate (from 2014 Board Approved)						**3.3%**

2.1.3 RATE BASE VARIANCE ANALYSIS

The following paragraphs and tables provide a narrative regarding the drivers of OHL's increase in rate base and working capital since OHL's 2014 Board Approved CoS Application.

OHL has provided the following variance analyses to account for the change in the Local Distribution Company's ("LDC") Rate Base:

- 2014 Board Approved against 2014 Actuals (MIFRS)
- 2014 Actuals (MIFRS) against 2015 Actuals (MIFRS)
- 2015 Actuals (MIFRS) against 2016 Actuals (MIFRS)
- 2016 Actuals (MIFRS) against 2017 Actuals (MIFRS)
- 2017 Actuals (MIFRS) against 2018 Actuals (MIFRS)
- 2018 Actuals (MIFRS) against 2019 Actuals (MIFRS)
- 2019 Actuals (MIFRS) against 2020 Actuals (MIFRS)
- 2020 Actuals (MIFRS) against 2021 Actuals (MIFRS)
- 2021 Actuals (MIFRS) against 2022 Actuals (MIFRS)
- 2022 Actuals (MIFRS) against 2023 Bridge (MIFRS)
- 2023 Bridge (MIFRS) against 2024 Test (MIFRS)

OHL invests in its distribution system, causing its net capital assets in service to increase every year. Net capital assets increase because of these investments in fixed assets but are offset by accumulated depreciation.

Detailed variance analysis regarding fixed asset additions can be found in 2.2.4 Asset Variance Analysis by OEB Category.

2.2.4 Asset Variance Analysis by OEB Category and in OHL's Distribution Plan included as Appendix 2-C Distribution System Plan.

Detailed variance analysis regarding recoverable OM&A expenses can be found in Exhibit 4, section 4.2.1 Detailed OM&A Variances.

Table 2-5 – 2014 Actuals (MIFRS) against 2014 Board Approved Rate Base Variance

Working Capital Allowance	2014 Actuals MIFRS	2014 Board Approved	Variance	% Variance
Recoverable OM&A Expenses	3,224,934	3,255,183	(30,249)	-1%
Taxes Other than Income Taxes	-		-	0%
Less Allocated Depreciation in OM&A	(53,409)	(60,470)	7,061	-12%
Total Eligible Distribution Expenses	**3,171,524**	**3,194,713**	**(23,189)**	**-1%**
Power Supply Expenses	26,967,661	27,763,022	(795,361)	-3%
Total Working Capital Expenses	**30,139,185**	**30,957,735**	**(818,550)**	**-3%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,013,919**	**$3,095,774**	**($81,855)**	**-3%**
Rate Base Calculation	**2014 Actuals MIFRS**	**2014 Board Approved**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	15,695,180	15,800,862	(105,682)	-1%
Ending Balance	16,391,075	16,639,780	(248,705)	-1%
Average Balance	**16,043,128**	**16,220,321**	**(177,194)**	**-1%**
Working Capital Allowance	3,013,919	3,095,774	(81,855)	-3%
Total Rate Base	**$19,057,046**	**$19,316,095**	**($259,048)**	**-1%**

The total Rate Base in 2014 Actuals of $19,316,095 was -$259,048 or -1% less than 2014 Board Approved. The main reasons for the variance are:

- Working capital allowance was lower than Board Approved mostly due to power supply expenses being lower than anticipated.
- Actual opening balance of capital assets was lower than Board Approved due to less transformer additions than anticipated.
- During 2014 there were $100,000 less capital additions than planned.

Table 2-6 – 2015 Actuals (MIFRS) against 2014 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2015 Actuals MIFRS	2014 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,287,582	3,224,934	62,649	2%
Taxes Other than Income Taxes	-	-	-	0%
Less Allocated Depreciation in OM&A	(68,841)	(53,409)	(15,432)	29%
Total Eligible Distribution Expenses	**3,218,741**	**3,171,524**	**47,217**	**1%**
Power Supply Expenses	29,745,385	26,967,661	2,777,724	10%
Total Working Capital Expenses	**32,964,126**	**30,139,185**	**2,824,941**	**9%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,296,413**	**$3,013,919**	**$282,494**	**9%**
Rate Base Calculation	**2015 Actuals MIFRS**	**2014 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	16,391,075	15,695,180	695,895	4%
Ending Balance	16,467,536	16,391,075	76,461	0%
Average Balance	**16,429,305**	**16,043,128**	**386,178**	**2%**
Working Capital Allowance	3,296,413	3,013,919	282,494	9%
Total Rate Base	**$19,725,718**	**$19,057,046**	**$668,672**	**4%**

The total Rate Base in 2015 Actuals of $19,725,718 was +$668,672 or +4% more than the 2014 Actuals. The main reasons for the variance are:

- Working capital allowance increased mainly as a result of power supply due to an increase in commodity pricing. OHL paid $5.1M more in global adjustment costs, which was offset partially by $3.4M less in energy costs and $0.6M less in wholesale market costs.
- Average net capital assets in service increased as a result of investments made in the distribution system.

Table 2-7 – 2016 Actuals (MIFRS) against 2015 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2016 Actuals MIFRS	2015 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,317,207	3,287,582	29,625	1%
Taxes Other than Income Taxes	-	-	-	0%
Less Allocated Depreciation in OM&A	(78,947)	(68,841)	(10,106)	15%
Total Eligible Distribution Expenses	**3,238,260**	**3,218,741**	**19,518**	**1%**
Power Supply Expenses	33,273,556	29,745,385	3,528,171	12%
Total Working Capital Expenses	**36,511,816**	**32,964,126**	**3,547,690**	**11%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,651,182**	**$3,296,413**	**$354,769**	**11%**
Rate Base Calculation	**2016 Actuals MIFRS**	**2015 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	16,467,536	16,391,075	76,461	0%
Ending Balance	17,131,085	16,467,536	663,550	4%
Average Balance	**16,799,310**	**16,429,305**	**370,005**	**2%**
Working Capital Allowance	3,651,182	3,296,413	354,769	11%
Total Rate Base	**$20,450,492**	**$19,725,718**	**$724,774**	**4%**

The total Rate Base in 2016 Actuals of $20,450,492 was +$724,774 or +4% more than the 2015 Actuals. The main reasons for the variance are:

- The working capital allowance increased mainly as a result of power supply expenses due to the increase in commodity pricing.
- Average net capital assets in service increased as a result of investments made in the distribution system. In 2016, OHL energized Riddell Row Servicing, which was a commercial subdivision.

Table 2-8 – 2017 Actuals (MIFRS) against 2016 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2017 Actuals MIFRS	2016 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,323,900	3,317,207	6,693	0%
Taxes Other than Income Taxes	-	-	-	0%
Less Allocated Depreciation in OM&A	(83,833)	(78,947)	(4,886)	6%
Total Eligible Distribution Expenses	**3,240,067**	**3,238,260**	**1,807**	**0%**
Power Supply Expenses	29,609,584	33,273,556	(3,663,971)	-11%
Total Working Capital Expenses	**32,849,651**	**36,511,816**	**(3,662,164)**	**-10%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,284,965**	**$3,651,182**	**($366,216)**	**-10%**
Rate Base Calculation	**2017 Actuals MIFRS**	**2016 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	17,131,085	16,467,536	663,550	4%
Ending Balance	18,083,203	17,131,085	952,117	6%
Average Balance	**17,607,144**	**16,799,310**	**807,834**	**5%**
Working Capital Allowance	3,284,965	3,651,182	(366,216)	-10%
Total Rate Base	**$20,892,109**	**$20,450,492**	**$441,617**	**2%**

The total Rate Base in 2017 Actuals of $20,892,109 was +$441,617 or +2% more than the 2016 Actuals. The main reasons for the variance are:

- The working capital allowance decreased mainly as a result of power supply expenses due to the decrease in commodity pricing, commencing in July 2017 from the introduction of the Ontario Fair Hydro Plan.
- Average net capital assets in service increased as a result of investments made in the distribution system. In 2017, OHL energized 6 residential subdivisions and completed Phase 1 of a 27.6 kV conversion of MS4-E Feeder (East of Faulkner).

Table 2-9 – 2018 Actuals (MIFRS) against 2017 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2018 Actuals MIFRS	2017 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,200,271	3,323,900	(123,629)	-4%
Taxes Other than Income Taxes	14,349	-	14,349	100%
Less Allocated Depreciation in OM&A	(89,283)	(83,833)	(5,450)	6%
Total Eligible Distribution Expenses	**3,125,336**	**3,240,067**	**(114,731)**	**-4%**
Power Supply Expenses	27,833,754	29,609,584	(1,775,830)	-6%
Total Working Capital Expenses	**30,959,090**	**32,849,651**	**(1,890,561)**	**-6%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,095,909**	**$3,284,965**	**($189,056)**	**-6%**
Rate Base Calculation	**2018 Actuals MIFRS**	**2017 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	18,083,203	17,131,085	952,117	6%
Ending Blance	18,691,380	18,083,203	608,178	3%
Average Balance	**18,387,292**	**17,607,144**	**780,148**	**4%**
Working Capital Allowance	3,095,909	3,284,965	(189,056)	-6%
Total Rate Base	**$21,483,201**	**$20,892,109**	**$591,091**	**3%**

The total Rate Base in 2018 Actuals of $21,483,201 was +$591,091 or +3% more than the 2017 Actual. The main reasons for the variance are:

- The working capital allowance decreased mainly as a result of power supply expenses due to the decrease in commodity pricing, commencing in July 2017 from the introduction of the Ontario Fair Hydro Plan.
- Average net capital assets in service increased as a result of investments made in the distribution system. OHL energized 6 subdivisions in 2017 as compared to 4 in 2018 and completed Phase 2 of a 27.6 kV conversion of MS4-E Feeder.

Table 2-10 – 2019 Actuals (MIFRS) against 2018 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2019 Actuals MIFRS	2018 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,442,073	3,200,271	241,802	8%
Taxes Other than Income Taxes	36,763	14,349	22,415	156%
Less Allocated Depreciation in OM&A	(94,914)	(89,283)	(5,630)	6%
Total Eligible Distribution Expenses	**3,383,923**	**3,125,336**	**258,587**	**8%**
Power Supply Expenses	29,083,782	27,833,754	1,250,028	4%
Total Working Capital Expenses	**32,467,705**	**30,959,090**	**1,508,614**	**5%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,246,770**	**$3,095,909**	**$150,861**	**5%**
Rate Base Calculation	**2019 Actuals MIFRS**	**2018 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	18,691,380	18,083,203	608,178	3%
Ending Balance	19,017,648	18,691,380	326,267	2%
Average Balance	**18,854,514**	**18,387,292**	**467,223**	**3%**
Working Capital Allowance	3,246,770	3,095,909	150,861	5%
Total Rate Base	**$22,101,285**	**$21,483,201**	**$618,084**	**3%**

The total Rate Base in 2019 Actuals of $22,101,285 was +$618,084 or +3% more than the 2018 Actuals. The main reasons for the variance are:

- The working capital allowance increased due to an increase in power supply expenses.
- Average net capital assets in service increased as a result of investments made in the distribution system. In 2019, there was a large 27.6 kV conversion project for Rear of Broadway and Riddell Rd feeder tie.

Table 2-11 – 2020 Actuals (MIFRS) against 2019 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2020 Actuals MIFRS	2019 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,197,840	3,442,073	(244,233)	-7%
Taxes Other than Income Taxes	41,103	36,763	4,339	12%
Less Allocated Depreciation in OM&A	(96,653)	(94,914)	(1,739)	2%
Total Eligible Distribution Expenses	**3,142,290**	**3,383,923**	**(241,633)**	**-7%**
Power Supply Expenses	32,771,802	29,083,782	3,688,020	13%
Total Working Capital Expenses	**35,914,093**	**32,467,705**	**3,446,388**	**11%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,591,409**	**$3,246,770**	**$344,639**	**11%**
Rate Base Calculation	**2020 Actuals MIFRS**	**2019 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	19,017,648	18,691,380	326,267	2%
Ending Blance	19,676,331	19,017,648	658,683	3%
Average Balance	**19,346,989**	**18,854,514**	**492,475**	**3%**
Working Capital Allowance	3,591,409	3,246,770	344,639	11%
Total Rate Base	**$22,938,398**	**$22,101,285**	**$837,114**	**4%**

The total Rate Base in 2020 Actuals of $22,938,398 was +$837,114 or +4% more than the 2019 Actuals. The main reasons for the variance are:

- The working capital allowance increased due to an increase in power supply expenses.
- Average net capital assets in service increased due to investments made in the distribution system. A major driver for the increase was due to a Third St/Second St 27.6KV Conversion project which was brought forward in order to upgrade the Express M26 feeder.

Table 2-12 – 2021 Actuals (MIFRS) against 2020 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2021 Actuals MIFRS	2020 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,380,858	3,197,840	183,018	6%
Taxes Other than Income Taxes	41,256	41,103	153	0%
Less Allocated Depreciation in OM&A	(98,795)	(96,653)	(2,143)	2%
Total Eligible Distribution Expenses	**3,323,319**	**3,142,290**	**181,029**	**6%**
Power Supply Expenses	29,029,339	32,771,802	(3,742,464)	-11%
Total Working Capital Expenses	**32,352,657**	**35,914,093**	**(3,561,435)**	**-10%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,235,266**	**$3,591,409**	**($356,144)**	**-10%**
Rate Base Calculation	**2021 Actuals MIFRS**	**2020 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	19,676,331	19,017,648	658,683	3%
Ending Balance	20,535,536	19,676,331	859,205	4%
Average Balance	**20,105,933**	**19,346,989**	**758,944**	**4%**
Working Capital Allowance	3,235,266	3,591,409	(356,144)	-10%
Total Rate Base	**$23,341,199**	**$22,938,398**	**$402,801**	**2%**

The total Rate Base in 2021 Actuals of $23,341,199 was +$402,801 or +2% more than the 2020 Actuals. The main reasons for the variance are:

- The working capital allowance decreased due to a decrease in power supply expenses.
- Average net capital assets in service increased due to investments made in the distribution system. A driver for the increase because of a large subdivision energization in Grand Valley, Mayberry Hill Phase 3A. The Town of Orangeville did a road widening and re-alignment along Centennial Road.

Table 2-13 – 2022 Actuals (MIFRS) against 2021 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2022 Actuals MIFRS	2021 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,639,401	3,380,858	258,543	8%
Taxes Other than Income Taxes	41,686	41,256	430	1%
Less Allocated Depreciation in OM&A	(99,368)	(98,795)	(573)	1%
Total Eligible Distribution Expenses	**3,581,719**	**3,323,319**	**258,401**	**8%**
Power Supply Expenses	30,671,964	29,029,339	1,642,625	6%
Total Working Capital Expenses	**34,253,683**	**32,352,657**	**1,901,025**	**6%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,425,368**	**$3,235,266**	**$190,103**	**6%**
Rate Base Calculation	**2022 Actuals MIFRS**	**2021 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	20,535,536	19,676,331	859,205	4%
Ending Blance	22,392,450	20,535,536	1,856,914	9%
Average Balance	**21,463,993**	**20,105,933**	**1,358,060**	**7%**
Working Capital Allowance	3,425,368	3,235,266	190,103	6%
Total Rate Base	**$24,889,362**	**$23,341,199**	**$1,548,162**	**7%**

The total Rate Base in 2022 Actuals of $24,889,362 was +$1,548,162 or +7% more than the 2021 Actuals. The main reasons for the variance are:

- The working capital allowance increased due to an increase in power supply expenses.
- Average net capital assets in service increased due to investments made in the distribution system. The driver for the increase was due to projects being brought forward from future years. MS-2 South Feeder conversion expanded to two new areas: Edelwild/Avonmore/Johanna ($492K) and Edelwild/Rustic/Cedar/Lawrence ($596K). These were large fiber projects where it was beneficial for OHL to bury duct jointly with the fiber company to minimize impacts to customers in those areas.

Table 2-14 – 2023 Bridge (MIFRS) against 2022 Actuals (MIFRS) Rate Base Variance

Working Capital Allowance	2023 Bridge MIFRS	2022 Actuals MIFRS	Variance	% Variance
Recoverable OM&A Expenses	3,812,695	3,639,401	173,294	5%
Taxes Other than Income Taxes	43,008	41,686	1,322	3%
Less Allocated Depreciation in OM&A	(97,851)	(99,368)	1,517	-2%
Total Eligible Distribution Expenses	**3,757,853**	**3,581,719**	**176,133**	**5%**
Power Supply Expenses	29,325,607	30,671,964	(1,346,356)	-4%
Total Working Capital Expenses	**33,083,460**	**34,253,683**	**(1,170,223)**	**-3%**
Working Capital Factor	10.0%	10.0%	0.0%	0%
Working Capital Allowance	**$3,308,346**	**$3,425,368**	**($117,022)**	**-3%**
Rate Base Calculation	**2023 Bridge MIFRS**	**2022 Actuals MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	22,392,450	20,535,536	1,856,914	9%
Ending Balance	23,340,703	22,392,450	948,252	4%
Average Balance	**22,866,577**	**21,463,993**	**1,402,583**	**7%**
Working Capital Allowance	3,308,346	3,425,368	(117,022)	-3%
Total Rate Base	**$26,174,923**	**$24,889,362**	**$1,285,561**	**5%**

The total Rate Base in 2023 Bridge of $26,174,923 was +$1,285,561 or +5% more than the 2022 Actuals. The main reasons for the variance are:

- The working capital allowance decreased due to a decrease in power supply expenses.
- Average net capital assets in service increased due to investments made in the distribution system. The main driver for the increase was the energization of 3 subdivisions, relative to no subdivisions in 2022. 62A-68 First Street, Mayberry Hill Phase 3A Block 43 and 670-690 Broadway have been energized in 2023.

Table 2-15 – 2024 Test (MIFRS) against 2023 Bridge (MIFRS) Rate Base Variance

Working Capital Allowance	2024 Test MIFRS	2023 Bridge MIFRS	Variance	% Variance
Recoverable OM&A Expenses	4,235,523	3,812,695	422,827	11%
Taxes Other than Income Taxes	44,298	43,008	1,290	3%
Less Allocated Depreciation in OM&A	(95,304)	(97,851)	2,547	-3%
Total Eligible Distribution Expenses	**4,184,517**	**3,757,853**	**426,664**	**11%**
Power Supply Expenses	29,298,887	29,356,772	(57,885)	0%
Total Working Capital Expenses	**33,483,404**	**33,114,624**	**368,780**	**1%**
Working Capital Factor	7.5%	10.0%	-2.5%	-25%
Working Capital Allowance	**$2,511,255**	**$3,311,462**	**($800,207)**	**-24%**
Rate Base Calculation	**2024 Test MIFRS**	**2023 Bridge MIFRS**	**Variance**	**% Variance**
Net Capital Assets in Service				
Opening Balance	23,340,703	22,392,450	948,252	4%
Ending Balance	25,121,954	23,340,703	1,781,251	8%
Average Balance	**24,231,328**	**22,866,577**	**1,364,752**	**6%**
Working Capital Allowance	2,511,255	3,311,462	(800,207)	-24%
Total Rate Base	**$26,742,584**	**$26,178,039**	**$564,545**	**2%**

The total Rate Base in 2024 Test of $26,742,584 was +$564,545 or +2% more than the 2023 Bridge. The main reasons for the variance are:

- The working capital allowance decreased due to the change in working capital factor from 10% to 7.5%.
- Average net capital assets in service increased due to investments made in the distribution system. The drivers for the increase are 2 subdivisions. Edgewood Valley Developments Phase 2B is a detached home development which is much larger than OHL’s typical subdivision connection projects. Another Grand Valley detached home development is expected to be energized and has been confirmed to OHL by the developers. Also contributing to the increase are a much-needed roof replacement, a new industry standard of GIS, a financial software upgrade and an enhanced customer portal. OHL’s building was built in 1990 and the roof is beyond its life expectancy. OHL was informed by a third party that it is in serious need of replacement. Our OHL’s existing customer portal is no longer being supported and is increasing cybersecurity concerns. It also provides customers with poor customer experience when they attempt to manage their accounts online.

For further details on 2024 Test Year additions to capital assets, please see Appendix 2-C Distribution System Plan.

2.2 FIXED ASSET CONTINUITY SCHEDULES

This Schedule presents a continuity schedule of OHL's investment in capital assets, the associated accumulated amortization, and the net book value for each Capital USoA account for the 2014 to 2022 Actuals, 2023 Bridge and 2024 Test Years.

OHL attests that the OEB Appendices 2-BA continuity statements presented starting at the next page reconcile with the calculated depreciation expenses under Exhibit 4 – Operating Costs and presented by asset account. OHL also attests that the net book value balances of in-service assets reported in Appendix 2-BA and balances reconcile with the rate base calculation. The Excel version of the OEB Appendices is filed in conjunction with this application.

OHL does not have any Asset Retirement Obligation related to decommissioning or asset retirement obligations.

The following tables are Board Appendix 2-BA, following the General Instruction to MIFRS.

- 2014 Actual is presented both in CGAAP and MIFRS
- 2015 to 2022, 2023 Bridge Year and 2024 Test Year are presented in MIFRS

OHL transitioned to IFRS reporting on January 1, 2014, which contributes to the large variance of accumulated depreciation and contributed capital shown in 2014. While the balance is presented in IFRS above, a reconciliation and continuity schedules comparison is provided further in this exhibit. OHL elected to follow the rate-regulated deemed cost exemption in converting from CGAAP to MIFRS as of January 1, 2014. As a result, the deemed cost under CGAAP became the new IFRS cost basis with accumulated depreciation and capital contributions recognized under CGAAP set to nil. There are no changes in the value of OHL's assets between CGAAP and MIFRS. OHL did not require any changes to its capitalization policies of overheads due to the change in accounting standard.

Accounting treatment of the cost of funds for construction work-in-progress

Virtually all of OHL's capital work is completed within the same fiscal year. In the event that a project does span over multiple years, OHL followed and will continue to follow the OEB's accounting processes and use account 2055 – Work in Progress.

OHL confirms there were no expenditures for non-distribution activities in the LDC's capital investment plan or actual expenditures for 2014-2022 or for the forecasted expenditures for 2023-2024

Continuity statements and depreciation expenses

OHL attests that the additions to accumulated depreciation in the fixed asset continuity statements agree to the depreciation expense schedules in section

2.3.2 Depreciation and Amortization by Asset Group.

2.2.1 CONTINUITY STATEMENTS

OHL has completed Fixed Asset Continuity Schedules, in accordance with Appendix 2- BA of the Filing Requirements, for each of the following years:

- 2014 OEB Approved
- 2014 to 2022 Actuals
- 2023 Bridge Year
- 2024 Test Year

All asset disposals are clearly identified in Chapter 2 Appendices 2-BA for all historical, bridge and test years.

Information on year-over-year variances are further explained in detail in section

2.2.4 Asset Variance Analysis by OEB Category below along with OHL's Distribution System Plan, which has been included as Appendix 2-C.

Table 2-16 – 2014 CGAAP Fixed Asset Continuity Schedule

Accounting Standard	CGAAP
Year	2014

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance 8	Additions 4	Disposals 6	Closing Balance	Opening Balance 8	Additions	Disposals 6	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 810,592	$ 128,647	$ -	$ 939,239	-$ 608,439	-$ 103,180	$ -	-$ 711,619	$ 227,620
CEC	1612	Land Rights (Formally known as Account 1906)	$ 63,213	$ 38,902	$ -	$ 102,115	-$ 23,240	$ -	$ -	-$ 23,240	$ 78,874
N/A	1805	Land	$ 122,655	$ -	$ -	$ 122,655	$ -	$ -	$ -	$ -	$ 122,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 930,403	$ 5,108	$ -	$ 935,511	-$ 577,773	-$ 39,329	$ -	-$ 617,103	$ 318,409
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 4,321,306	$ 109,302	-$ 29,793	$ 4,400,814	-$ 2,780,573	-$ 55,221	$ 23,064	-$ 2,812,730	$ 1,588,084
47	1835	Overhead Conductors & Devices	$ 3,825,721	$ 94,691	-$ 17,432	$ 3,902,980	-$ 2,168,725	-$ 37,231	$ 14,313	-$ 2,191,643	$ 1,711,337
47	1840	Underground Conduit	$ 4,863,827	$ 474,995		$ 5,338,822	-$ 2,154,940	-$ 71,396	$ -	-$ 2,226,337	$ 3,112,485
47	1845	Underground Conductors & Devices	$ 5,898,612	$ 311,597	$ -	$ 6,210,208	-$ 2,722,911	-$ 159,699	$ -	-$ 2,882,610	$ 3,327,599
47	1850	Line Transformers	$ 8,034,628	$ 380,201	-$ 140,332	$ 8,274,497	-$ 4,001,217	-$ 143,567	$ 120,610	-$ 4,024,174	$ 4,250,323
47	1855	Services (Overhead & Underground)	$ 2,545,217	$ 193,244	$ -	$ 2,738,461	-$ 1,546,342	-$ 42,826	$ -	-$ 1,589,167	$ 1,149,294
47	1860	Meters	$ 2,069,992	$ 51,973	-$ 40,431	$ 2,081,534	-$ 471,419	-$ 129,170	$ 15,163	-$ 585,426	$ 1,496,108
47	1860	Meters (Smart Meters)		$ -	$ -	$ -		$ -	$ -	$ -	$ -
N/A	1905	Land	$ 144,400	$ -	$ -	$ 144,400	$ -	$ -	$ -	$ -	$ 144,400
47	1908	Buildings & Fixtures	$ 2,826,685	$ 15,781	-$ 1,800	$ 2,840,666	-$ 1,049,853	-$ 76,449	$ 485	-$ 1,125,818	$ 1,714,848
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 222,975	$ -	$ -	$ 222,975	-$ 133,143	-$ 14,940	$ -	-$ 148,083	$ 74,892
8	1915	Office Furniture & Equipment (5 years)		$ -	$ -	$ -		$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 135,741	$ 28,386	-$ 10,736	$ 153,392	-$ 91,504	-$ 22,358	$ 9,756	-$ 104,106	$ 49,287
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)		$ -	$ -	$ -		$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)		$ -	$ -	$ -		$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,011,299	$ 327,917	-$ 210,825	$ 1,128,390	-$ 789,465	-$ 53,102	$ 202,977	-$ 639,590	$ 488,800
8	1935	Stores Equipment	$ 34,593	$ -	$ -	$ 34,593	-$ 28,381	-$ 1,215	$ -	-$ 29,596	$ 4,997
8	1940	Tools, Shop & Garage Equipment	$ 131,483	$ 3,704	-$ 23,095	$ 112,093	-$ 110,219	-$ 3,837	$ 23,005	-$ 91,051	$ 21,042
8	1945	Measurement & Testing Equipment	$ 31,860	$ 365	-$ 13,207	$ 19,019	-$ 16,831	-$ 1,812	$ 13,207	-$ 5,436	$ 13,583
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 18,701	$ -	$ -	$ 18,701	-$ 18,576	-$ 125	$ -	-$ 18,701	$ -
8	1955	Communication Equipment (Smart Meters)		$ -	$ -	$ -		$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 162,220	$ 2,350	$ -	$ 164,570	-$ 63,546	-$ 15,891	$ -	-$ 79,436	$ 85,133
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	-$ 4,440,007	-$ 538,014	$ -	-$ 4,978,021	$ 1,286,162	$ 103,165	$ -	$ 1,389,327	-$ 3,588,694
47	2440	Deferred Revenue5	$ -		$ -	$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease7	$ -	$ -	$ -	$ -	$ -			$ -	$ -
		Sub-Total	**$ 33,766,116**	**$ 1,629,149**	**-$ 487,651**	**$ 34,907,614**	**-$ 18,070,936**	**-$ 868,183**	**$ 422,580**	**-$ 18,516,540**	**$ 16,391,075**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 33,766,116**	**$ 1,629,149**	**-$ 487,651**	**$ 34,907,614**	**-$ 18,070,936**	**-$ 868,183**	**$ 422,580**	**-$ 18,516,540**	**$ 16,391,075**
		Construction Work In Progress		$ 45,233		$ 45,233				$ -	$ 45,233
		Total PP&E	**$ 33,766,116**	**$ 1,674,383**	**-$ 487,651**	**$ 34,952,848 ##**	**-$ 18,070,936**	**-$ 868,183**	**$ 422,580**	**-$ 18,516,540**	**$ 16,436,308**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable6									
		Total						**-$ 868,183**			

			Less: Fully Allocated Depreciation	
10		Transportation	Transportation	-$ 46,420
8		Stores Equipment	Stores Equipment	-$ 1,215
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 3,837
8		Measurement & Testing Equipment	Measurement & Testing Equipment	-$ 1,812
8		Communications Equipment	Communications Equipment	-$ 125
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 820,548**

Table 2-17 – 2014 MIFRS Fixed Asset Continuity Schedule

Accounting Standard MIFRS
Year 2014

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 202,153	$ 128,876	$ -	$ 331,029	$ -	-$ 103,180	$ -	-$ 103,180	$ 227,849
CEC	1612	Land Rights (Formally known as Account 1906)	$ 39,972	$ 38,902	$ -	$ 78,874	$ -	$ -	$ -	$ -	$ 78,874
N/A	1805	Land	$ 122,655	$ -	$ -	$ 122,655	$ -	$ -	$ -	$ -	$ 122,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 352,630	$ 5,108	$ -	$ 357,738	$ -	-$ 39,329	$ -	-$ 39,329	$ 318,409
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,423,630	$ 109,302	-$ 6,730	$ 1,526,202	$ -	-$ 52,432	$ -	-$ 52,432	$ 1,473,770
47	1835	Overhead Conductors & Devices	$ 1,598,812	$ 94,691	-$ 3,119	$ 1,690,384	$ -	-$ 36,105	$ -	-$ 36,105	$ 1,654,279
47	1840	Underground Conduit	$ 2,194,259	$ 474,995	$ -	$ 2,669,254	$ -	-$ 59,231	$ -	-$ 59,231	$ 2,610,023
47	1845	Underground Conductors & Devices	$ 2,550,182	$ 311,597	$ -	$ 2,861,779	$ -	-$ 139,078	$ -	-$ 139,078	$ 2,722,701
47	1850	Line Transformers	$ 2,673,599	$ 380,201	-$ 19,938	$ 3,033,862	$ -	-$ 103,788	$ 215	-$ 103,573	$ 2,930,288
47	1855	Services (Overhead & Underground)	$ 651,180	$ 193,244	$ -	$ 844,424	$ -	-$ 31,817	$ -	-$ 31,817	$ 812,607
47	1860	Meters	$ 1,467,670	$ 51,973	-$ 25,472	$ 1,494,171	$ -	-$ 120,456	$ 204	-$ 120,252	$ 1,373,919
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 144,400	$ -	$ -	$ 144,400	$ -	$ -	$ -	$ -	$ 144,400
47	1908	Buildings & Fixtures	$ 1,776,831	$ 15,781	-$ 1,333	$ 1,791,280	$ -	-$ 76,449	$ 18	-$ 76,432	$ 1,714,848
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 89,832	$ -	$ -	$ 89,832	$ -	-$ 14,940	$ -	-$ 14,940	$ 74,892
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 44,238	$ 28,157	-$ 1,578	$ 70,817	$ -	-$ 22,358	$ 598	-$ 21,759	$ 49,057
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 221,833	$ 327,917	-$ 8,830	$ 540,921	$ -	-$ 53,102	$ 981	-$ 52,121	$ 488,800
8	1935	Stores Equipment	$ 6,212	$ -	$ -	$ 6,212	$ -	-$ 1,215	$ -	-$ 1,215	$ 4,997
8	1940	Tools, Shop & Garage Equipment	$ 21,264	$ 3,704	-$ 102	$ 24,867	$ -	-$ 3,837	$ 12	-$ 3,825	$ 21,042
8	1945	Measurement & Testing Equipment	$ 15,030	$ 365	$ -	$ 15,395	$ -	-$ 1,812	$ -	-$ 1,812	$ 13,583
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 125	$ -	$ -	$ 125	$ -	-$ 125	$ -	-$ 125	$ 0
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 98,674	$ 2,350	$ -	$ 101,024	$ -	-$ 15,891	$ -	-$ 15,891	$ 85,133
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	$ -	-$ 538,014	$ -	-$ 538,014	$ -	$ 6,962	$ -	$ 6,962	-$ 531,052
	2005	Property Under Finance Lease[7]	0	0	0	$ -	0	0	0	$ -	$ -
		Sub-Total	**$ 15,695,180**	**$ 1,629,149**	**-$ 67,101**	**$ 17,257,229**	**$ -**	**-$ 868,183**	**$ 2,029**	**-$ 866,154**	**$ 16,391,074**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 15,695,180**	**$ 1,629,149**	**-$ 67,101**	**$ 17,257,229**	**$ -**	**-$ 868,183**	**$ 2,029**	**-$ 866,154**	**$ 16,391,074**
		Construction Work In Progress		$ 45,233		$ 45,233				$ -	$ 45,233
		Total PP&E	**$ 15,695,180**	**$ 1,674,383**	**-$ 67,101**	**$ 17,302,462**	**$ -**	**-$ 868,183**	**$ 2,029**	**-$ 866,154**	**$ 16,436,308**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 868,183**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 46,420
8		Stores Equipment	Stores Equipment	-$ 1,215
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 3,837
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 1,812
8		Communications Equipment	Communications Equipment	-$ 125
47		Deferred Revenue	Deferred Revenue	$ 6,962
		1629149.43	**Net Depreciation**	**-$ 821,736**

Table 2-18 – 2015 MIFRS Fixed Asset Continuity Schedule

Accounting Standard	MIFRS
Year	2015

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 331,029	$ 17,669	-$ 56,259	$ 292,440	-$ 103,180	-$ 84,971	$ 54,639	-$ 133,512	$ 158,927
CEC	1612	Land Rights (Formally known as Account 1906)	$ 78,874	$ 23,933	$ -	$ 102,808	$ -	$ -	$ -	$ -	$ 102,808
N/A	1805	Land	$ 122,655	$ -	-$ 100,000	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 357,738	$ 38,633	$ -	$ 396,371	-$ 39,329	-$ 40,497	$ -	-$ 79,827	$ 316,544
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,526,202	$ 110,012	-$ 2,923	$ 1,633,291	-$ 52,432	-$ 52,507	$ 221	-$ 104,717	$ 1,528,574
47	1835	Overhead Conductors & Devices	$ 1,690,384	$ 73,798	-$ 15,900	$ 1,748,282	-$ 36,105	-$ 37,090	$ 1,295	-$ 71,900	$ 1,676,382
47	1840	Underground Conduit	$ 2,669,254	$ 282,139	$ -	$ 2,951,393	-$ 59,231	-$ 66,704	$ -	-$ 125,935	$ 2,825,458
47	1845	Underground Conductors & Devices	$ 2,861,779	$ 132,212	$ -	$ 2,993,990	-$ 139,078	-$ 145,234	$ -	-$ 284,312	$ 2,709,679
47	1850	Line Transformers	$ 3,033,862	$ 344,561	-$ 10,726	$ 3,367,697	-$ 103,573	-$ 108,446	$ 1,420	-$ 210,599	$ 3,157,097
47	1855	Services (Overhead & Underground)	$ 844,424	$ 84,866	$ -	$ 929,290	-$ 31,817	-$ 33,233	$ -	-$ 65,050	$ 864,240
47	1860	Meters	$ 1,494,171	$ 22,300	-$ 12,260	$ 1,504,211	-$ 120,252	-$ 120,634	$ 1,607	-$ 239,279	$ 1,264,931
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 144,400	$ -	$ -	$ 144,400	$ -	$ -	$ -	$ -	$ 144,400
47	1908	Buildings & Fixtures	$ 1,791,280	$ 54,950	$ -	$ 1,846,230	-$ 76,432	-$ 77,883	$ -	-$ 154,315	$ 1,691,915
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 89,832	$ 6,551	-$ 988	$ 95,394	-$ 14,940	-$ 14,237	$ 798	-$ 28,379	$ 67,015
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 70,817	$ 25,403	-$ 11,413	$ 84,807	-$ 21,759	-$ 20,259	$ 8,989	-$ 33,030	$ 51,777
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 540,921	$ 51,619	$ -	$ 592,540	-$ 52,121	-$ 69,232	$ -	-$ 121,353	$ 471,187
8	1935	Stores Equipment	$ 6,212	$ -	$ -	$ 6,212	-$ 1,215	-$ 1,150	$ -	-$ 2,365	$ 3,847
8	1940	Tools, Shop & Garage Equipment	$ 24,867	$ 9,121	$ -	$ 33,988	-$ 3,825	-$ 4,320	$ -	-$ 8,145	$ 25,843
8	1945	Measurement & Testing Equipment	$ 15,395	$ 11,212	$ -	$ 26,607	-$ 1,812	-$ 2,532	$ -	-$ 4,344	$ 22,263
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 125	$ 1,651	$ -	$ 1,775	-$ 125	-$ 124	$ -	-$ 248	$ 1,527
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 101,024	$ 2,479	$ -	$ 103,503	-$ 15,891	-$ 16,876	$ -	-$ 32,767	$ 70,736
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 538,014	-$ 200,284	$ 5,589	-$ 732,709	$ 6,962	$ 15,819	-$ 342	$ 22,439	-$ 710,270
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 17,257,229**	**$ 1,092,823**	**-$ 204,879**	**$ 18,145,173**	**-$ 866,154**	**-$ 880,110**	**$ 68,626**	**-$ 1,677,638**	**$ 16,467,535**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -			$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 17,257,229**	**$ 1,092,823**	**-$ 204,879**	**$ 18,145,173**	**-$ 866,154**	**-$ 880,110**	**$ 68,626**	**-$ 1,677,638**	**$ 16,467,535**
		Construction Work In Progress	$ 45,233	-$ 18,873		$ 26,360				$ -	$ 26,360
		Total PP&E	**$ 17,302,462**	**$ 1,073,950**	**-$ 204,879**	**$ 18,171,533**	**-$ 866,154**	**-$ 880,110**	**$ 68,626**	**-$ 1,677,638**	**$ 16,493,895**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 880,110**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 60,716
8		Stores Equipment	Stores Equipment	-$ 1,150
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 4,320
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 2,532
8		Communications Equipment	Communications Equipment	-$ 124
47		Deferred Revenue	Deferred Revenue	$ 15,819
		1092822.76	**Net Depreciation**	**-$ 827,088**

Table 2-19 – 2016 MIFRS Fixed Asset Continuity Schedule

Year **2016**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	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)	$ 292,440	$ 16,184	$ -	$ 308,624	-$ 133,512	-$ 64,625	$ -	-$ 198,137	$ 110,487
CEC	1612	Land Rights (Formally known as Account 1906)	$ 102,808	$ 9,060	$ -	$ 111,868	$ -	$ -	$ -	$ -	$ 111,868
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 396,371	$ 59,927	$ -	$ 456,298	-$ 79,827	-$ 32,130	$ -	-$ 111,957	$ 344,341
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,633,291	$ 101,069	-$ 5,119	$ 1,729,241	-$ 104,717	-$ 49,045	$ 701	-$ 153,061	$ 1,576,180
47	1835	Overhead Conductors & Devices	$ 1,748,282	$ 77,897	-$ 8,090	$ 1,818,089	-$ 71,900	-$ 37,246	$ 1,444	-$ 107,702	$ 1,710,387
47	1840	Underground Conduit	$ 2,951,393	$ 397,357	$ -	$ 3,348,750	-$ 125,935	-$ 73,217	$ -	-$ 199,152	$ 3,149,598
47	1845	Underground Conductors & Devices	$ 2,993,990	$ 620,750	$ -	$ 3,614,740	-$ 284,312	-$ 128,590	$ -	-$ 412,902	$ 3,201,839
47	1850	Line Transformers	$ 3,367,697	$ 280,720	-$ 15,150	$ 3,633,268	-$ 210,599	-$ 113,829	$ 1,877	-$ 322,551	$ 3,310,716
47	1855	Services (Overhead & Underground)	$ 929,290	$ 144,507	$ -	$ 1,073,797	-$ 65,050	-$ 35,474	$ -	-$ 100,524	$ 973,273
47	1860	Meters	$ 1,504,211	$ 85,035	-$ 2,921	$ 1,586,325	-$ 239,279	-$ 122,786	$ 591	-$ 361,474	$ 1,224,850
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 144,400	$ -	$ -	$ 144,400	$ -	$ -	$ -	$ -	$ 144,400
47	1908	Buildings & Fixtures	$ 1,846,230	$ 975	$ -	$ 1,847,205	-$ 154,315	-$ 79,261	$ -	-$ 233,575	$ 1,613,629
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 95,394	$ 1,182	$ -	$ 96,577	-$ 28,379	-$ 14,312	$ -	-$ 42,691	$ 53,886
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 84,807	$ 30,145	-$ 6,067	$ 108,885	-$ 33,030	-$ 18,758	$ 6,067	-$ 45,721	$ 63,164
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 592,540	$ 93,016	-$ 12,988	$ 672,567	-$ 121,353	-$ 76,474	$ 7,227	-$ 190,600	$ 481,967
8	1935	Stores Equipment	$ 6,212	$ -	$ -	$ 6,212	-$ 2,365	-$ 1,153	$ -	-$ 3,517	$ 2,694
8	1940	Tools, Shop & Garage Equipment	$ 33,988	$ 9,818	-$ 42	$ 43,764	-$ 8,145	-$ 5,166	$ 42	-$ 13,269	$ 30,495
8	1945	Measurement & Testing Equipment	$ 26,607	$ 1,748	$ -	$ 28,355	-$ 4,344	-$ 3,065	$ -	-$ 7,409	$ 20,947
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,775	$ -	$ -	$ 1,775	-$ 248	-$ 165	$ -	-$ 413	$ 1,362
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 103,503	$ 11,600	$ -	$ 115,103	-$ 32,767	-$ 17,360	$ -	-$ 50,127	$ 64,976
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 732,709	-$ 395,789	$ -	-$ 1,128,498	$ 22,439	$ 23,431	$ -	$ 45,869	-$ 1,082,629
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 18,145,173**	**$ 1,545,201**	**-$ 50,376**	**$ 19,639,998**	**-$ 1,677,638**	**-$ 849,223**	**$ 17,948**	**-$ 2,508,913**	**$ 17,131,085**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 18,145,173**	**$ 1,545,201**	**-$ 50,376**	**$ 19,639,998**	**-$ 1,677,638**	**-$ 849,223**	**$ 17,948**	**-$ 2,508,913**	**$ 17,131,085**
		Construction Work In Progress	$ 26,360	-$ 12,352		$ 14,008				$ -	$ 14,008
		Total PP&E	**$ 18,171,533**	**$ 1,532,849**	**-$ 50,376**	**$ 19,654,006**	**-$ 1,677,638**	**-$ 849,223**	**$ 17,948**	**-$ 2,508,913**	**$ 17,145,094**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 849,223**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 69,399
8		Stores Equipment	Stores Equipment	-$ 1,153
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 5,166
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 3,065
8		Communications Equipment	Communications Equipment	-$ 165
47		Deferred Revenue	Deferred Revenue	$ 23,431
		1545201.25	**Net Depreciation**	**-$ 793,706**

Table 2-20 – 2017 MIFRS Fixed Asset Continuity Schedule

Year 2017

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 308,624	$ 53,881	-$ 21,652	$ 340,853	-$ 198,137	-$ 52,426	$ 16,689	-$ 233,874	$ 106,979
CEC	1612	Land Rights (Formally known as Account 1906)	$ 111,868	$ 1,250	$ -	$ 113,118	$ -	$ -	$ -	$ -	$ 113,118
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 456,298	$ 27,393	$ -	$ 483,691	-$ 111,957	-$ 32,849	$ -	-$ 144,806	$ 338,885
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,729,241	$ 137,524	-$ 2,646	$ 1,864,120	-$ 153,061	-$ 51,392	$ 478	-$ 203,975	$ 1,660,145
47	1835	Overhead Conductors & Devices	$ 1,818,089	$ 81,349	$ -	$ 1,899,438	-$ 107,702	-$ 38,288	$ -	-$ 145,990	$ 1,753,448
47	1840	Underground Conduit	$ 3,348,750	$ 817,759	$ -	$ 4,166,509	-$ 199,152	-$ 85,029	$ -	-$ 284,181	$ 3,882,328
47	1845	Underground Conductors & Devices	$ 3,614,740	$ 417,170	-$ 9,048	$ 4,022,863	-$ 412,902	-$ 142,008	$ 3,927	-$ 550,983	$ 3,471,880
47	1850	Line Transformers	$ 3,633,268	$ 545,063	-$ 13,823	$ 4,164,507	-$ 322,551	-$ 124,375	$ 2,761	-$ 444,165	$ 3,720,342
47	1855	Services (Overhead & Underground)	$ 1,073,797	$ 321,690	$ -	$ 1,395,488	-$ 100,524	-$ 40,154	$ -	-$ 140,678	$ 1,254,809
47	1860	Meters	$ 1,586,325	$ 76,111	-$ 18,583	$ 1,643,853	-$ 361,474	-$ 125,895	$ 5,873	-$ 481,496	$ 1,162,357
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 144,400	$ -	-$ 33,559	$ 110,842	$ -	$ -	$ -	$ -	$ 110,842
47	1908	Buildings & Fixtures	$ 1,847,205	$ 6,638	$ -	$ 1,853,842	-$ 233,575	-$ 79,203	$ -	-$ 312,778	$ 1,541,065
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 96,577	$ 2,131	$ -	$ 98,707	-$ 42,691	-$ 12,303	$ -	-$ 54,994	$ 43,714
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 108,885	$ 5,051	-$ 16,408	$ 97,527	-$ 45,721	-$ 19,123	$ 10,997	-$ 53,847	$ 43,680
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 672,567	$ 35,650	-$ 43,129	$ 665,088	-$ 190,600	-$ 79,179	$ 26,572	-$ 243,207	$ 421,881
8	1935	Stores Equipment	$ 6,212	$ 1,899	$ -	$ 8,111	-$ 3,517	-$ 930	$ -	-$ 4,447	$ 3,663
8	1940	Tools, Shop & Garage Equipment	$ 43,764	$ 600	$ -	$ 44,364	-$ 13,269	-$ 5,353	$ -	-$ 18,622	$ 25,742
8	1945	Measurement & Testing Equipment	$ 28,355	$ 14,934	$ -	$ 43,289	-$ 7,409	-$ 3,833	$ -	-$ 11,242	$ 32,048
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,775	$ -	$ -	$ 1,775	-$ 413	-$ 165	$ -	-$ 578	$ 1,197
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 115,103	$ 5,516	$ -	$ 120,619	-$ 50,127	-$ 17,989	$ -	-$ 68,116	$ 52,502
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 1,128,498	-$ 633,962	$ -	-$ 1,762,460	$ 45,869	$ 36,513	$ -	$ 82,382	-$ 1,680,078
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 19,639,998**	**$ 1,917,648**	**-$ 158,847**	**$ 21,398,798**	**-$ 2,508,913**	**-$ 873,981**	**$ 67,297**	**-$ 3,315,596**	**$ 18,083,202**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 19,639,998**	**$ 1,917,648**	**-$ 158,847**	**$ 21,398,798**	**-$ 2,508,913**	**-$ 873,981**	**$ 67,297**	**-$ 3,315,596**	**$ 18,083,202**
		Construction Work In Progress	$ 14,008	$ 9,021		$ 23,029				$ -	$ 23,029
		Total PP&E	**$ 19,654,006**	**$ 1,926,669**	**-$ 158,847**	**$ 21,421,828**	**-$ 2,508,913**	**-$ 873,981**	**$ 67,297**	**-$ 3,315,596**	**$ 18,106,231**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 873,981**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 73,551
8		Stores Equipment	Stores Equipment	-$ 930
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 5,353
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 3,833
8		Communications Equipment	Communications Equipment	-$ 165
47		Deferred Revenue	Deferred Revenue	$ 36,513
		1917647.85	**Net Depreciation**	**-$ 826,662**

Table 2-21 – 2018 MIFRS Fixed Asset Continuity Schedule

Year **2018**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	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)	$ 340,853	$ 22,371	-$ 1,433	$ 361,791	-$ 233,874	-$ 46,326	$ 1,147	-$ 279,053	$ 82,738
CEC	1612	Land Rights (Formally known as Account 1906)	$ 113,118	$ -	$ -	$ 113,118	$ -	$ -	$ -	$ -	$ 113,118
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 483,691	$ 14,841	$ -	$ 498,532	-$ 144,806	-$ 34,126	$ -	-$ 178,931	$ 319,601
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 1,864,120	$ 205,188	$ -	$ 2,069,307	-$ 203,975	-$ 55,453	$ -	-$ 259,428	$ 1,809,880
47	1835	Overhead Conductors & Devices	$ 1,899,438	$ 157,462	$ -	$ 2,056,900	-$ 145,990	-$ 40,278	$ -	-$ 186,267	$ 1,870,632
47	1840	Underground Conduit	$ 4,166,509	$ 116,780	$ -	$ 4,283,288	-$ 284,181	-$ 94,253	$ -	-$ 378,433	$ 3,904,855
47	1845	Underground Conductors & Devices	$ 4,022,863	$ 245,072	-$ 24,475	$ 4,243,460	-$ 550,983	-$ 150,303	$ 4,157	-$ 697,130	$ 3,546,331
47	1850	Line Transformers	$ 4,164,507	$ 320,205	-$ 16,498	$ 4,468,214	-$ 444,165	-$ 133,936	$ 3,915	-$ 574,187	$ 3,894,027
47	1855	Services (Overhead & Underground)	$ 1,395,488	$ 133,625	$ -	$ 1,529,112	-$ 140,678	-$ 47,032	$ -	-$ 187,710	$ 1,341,402
47	1860	Meters	$ 1,643,853	$ 143,901	-$ 20,864	$ 1,766,891	-$ 481,496	-$ 130,623	$ 8,421	-$ 603,697	$ 1,163,194
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 110,842	$ -	$ -	$ 110,842	$ -	$ -	$ -	$ -	$ 110,842
47	1908	Buildings & Fixtures	$ 1,853,842	$ 69,750	$ -	$ 1,923,593	-$ 312,778	-$ 80,267	$ -	-$ 393,045	$ 1,530,548
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 98,707	$ 29,417	$ -	$ 128,125	-$ 54,994	-$ 12,990	$ -	-$ 67,984	$ 60,141
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 97,527	$ 13,899	-$ 14,565	$ 96,860	-$ 53,847	-$ 17,901	$ 14,530	-$ 57,218	$ 39,642
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 665,088	$ 293,225	-$ 45,014	$ 913,299	-$ 243,207	-$ 80,851	$ 22,507	-$ 301,551	$ 611,748
8	1935	Stores Equipment	$ 8,111	$ -	$ -	$ 8,111	-$ 4,447	-$ 784	$ -	-$ 5,232	$ 2,879
8	1940	Tools, Shop & Garage Equipment	$ 44,364	$ 15,957	$ -	$ 60,321	-$ 18,622	-$ 5,720	$ -	-$ 24,342	$ 35,979
8	1945	Measurement & Testing Equipment	$ 43,289	$ 1,911	$ -	$ 45,200	-$ 11,242	-$ 4,576	$ -	-$ 15,818	$ 29,383
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,775	$ -	$ -	$ 1,775	-$ 578	-$ 165	$ -	-$ 743	$ 1,032
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 120,619	$ 4,166	$ -	$ 124,784	-$ 68,116	-$ 17,490	$ -	-$ 85,607	$ 39,178
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 1,762,460	-$ 205,712	$ -	-$ 1,968,172	$ 82,382	$ 47,366	$ -	$ 129,749	-$ 1,838,424
	2005	Property Under Finance Lease[7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 21,398,798**	**$ 1,582,058**	**-$ 122,849**	**$ 22,858,008**	**-$ 3,315,596**	**-$ 905,707**	**$ 54,675**	**-$ 4,166,628**	**$ 18,691,380**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 21,398,798**	**$ 1,582,058**	**-$ 122,849**	**$ 22,858,008**	**-$ 3,315,596**	**-$ 905,707**	**$ 54,675**	**-$ 4,166,628**	**$ 18,691,380**
		Construction Work In Progress	$ 23,029	$ 6,331		$ 29,360				$ -	$ 29,360
		Total PP&E	**$ 21,421,828**	**$ 1,588,389**	**-$ 122,849**	**$ 22,887,368**	**-$ 3,315,596**	**-$ 905,707**	**$ 54,675**	**-$ 4,166,628**	**$ 18,720,740**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 905,707**			

CCA Class		Description	Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 78,038
8		Stores Equipment	Stores Equipment	-$ 784
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 5,720
8		Power Operated Equipment	Power Operated Equipment	$ -
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 4,576
8		Communications Equipment	Communications Equipment	-$ 165
47		Deferred Revenue	Deferred Revenue	$ 47,366
		1582057.81	**Net Depreciation**	**-$ 863,790**

Table 2-22 – 2019 MIFRS Fixed Asset Continuity Schedule

Year **2019**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	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)	$ 361,791	$ 49,155	-$ 4,177	$ 406,769	-$ 279,053	-$ 38,302	$ 1,874	-$ 315,481	$ 91,288
CEC	1612	Land Rights (Formally known as Account 1906)	$ 113,118	$ 22,600	$ -	$ 135,718	$ -	$ -	$ -	$ -	$ 135,718
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 498,532	$ 20,345	$ -	$ 518,877	-$ 178,931	-$ 34,927	$ -	-$ 213,859	$ 305,018
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,069,307	$ 196,315	$ -	$ 2,265,622	-$ 259,428	-$ 59,587	$ -	-$ 319,015	$ 1,946,608
47	1835	Overhead Conductors & Devices	$ 2,056,900	$ 208,091	$ -	$ 2,264,991	-$ 186,267	-$ 43,324	$ -	-$ 229,592	$ 2,035,399
47	1840	Underground Conduit	$ 4,283,288	$ 102,298	$ -	$ 4,385,586	-$ 378,433	-$ 96,404	$ -	-$ 474,838	$ 3,910,749
47	1845	Underground Conductors & Devices	$ 4,243,460	$ 185,171	$ -	$ 4,428,631	-$ 697,130	-$ 155,356	$ -	-$ 852,485	$ 3,576,146
47	1850	Line Transformers	$ 4,468,214	$ 266,310	-$ 21,938	$ 4,712,586	-$ 574,187	-$ 140,375	$ 5,508	-$ 709,054	$ 4,003,532
47	1855	Services (Overhead & Underground)	$ 1,529,112	$ 90,318	$ -	$ 1,619,431	-$ 187,710	-$ 49,972	$ -	-$ 237,683	$ 1,381,748
47	1860	Meters	$ 1,766,891	$ 105,516	-$ 45,022	$ 1,827,385	-$ 603,697	-$ 135,231	$ 23,014	-$ 715,914	$ 1,111,471
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 110,842	$ -	$ -	$ 110,842	$ -	$ -	$ -	$ -	$ 110,842
47	1908	Buildings & Fixtures	$ 1,923,593	$ 35,528	$ -	$ 1,959,121	-$ 393,045	-$ 82,093	$ -	-$ 475,138	$ 1,483,983
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 128,125	$ 19,450	-$ 13,640	$ 133,934	-$ 67,984	-$ 14,080	$ 11,550	-$ 70,514	$ 63,420
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 96,860	$ 30,296	-$ 5,548	$ 121,609	-$ 57,218	-$ 19,205	$ 5,055	-$ 71,368	$ 50,241
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 913,299	$ 32,823	-$ 11,785	$ 934,337	-$ 301,551	-$ 83,357	$ 11,785	-$ 373,124	$ 561,214
8	1935	Stores Equipment	$ 8,111	$ -	$ -	$ 8,111	-$ 5,232	-$ 600	$ -	-$ 5,832	$ 2,279
8	1940	Tools, Shop & Garage Equipment	$ 60,321	$ 1,014	$ -	$ 61,335	-$ 24,342	-$ 5,970	$ -	-$ 30,311	$ 31,024
8	1945	Measurement & Testing Equipment	$ 45,200	$ 2,997	$ -	$ 48,197	-$ 15,818	-$ 4,821	$ -	-$ 20,639	$ 27,559
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,775	$ -	$ -	$ 1,775	-$ 743	-$ 165	$ -	-$ 908	$ 867
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 124,784	$ -	$ -	$ 124,784	-$ 85,607	-$ 13,962	$ -	-$ 99,569	$ 25,216
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 1,968,172	-$ 115,021	$ 45,082	-$ 2,038,111	$ 129,749	$ 51,039	-$ 2,004	$ 178,784	-$ 1,859,327
	2005	Property Under Finance Lease [7]	$ -	0	0	$ -	$ -	0	0	$ -	$ -
		Sub-Total	**$ 22,858,008**	**$ 1,253,207**	**-$ 57,028**	**$ 24,054,186**	**-$ 4,166,628**	**-$ 926,694**	**$ 56,782**	**-$ 5,036,539**	**$ 19,017,647**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 22,858,008**	**$ 1,253,207**	**-$ 57,028**	**$ 24,054,186**	**-$ 4,166,628**	**-$ 926,694**	**$ 56,782**	**-$ 5,036,539**	**$ 19,017,647**
		Construction Work In Progress	$ 29,360	-$ 28,510		$ 850				$ -	$ 850
		Total PP&E	**$ 22,887,368**	**$ 1,224,697**	**-$ 57,028**	**$ 24,055,036**	**-$ 4,166,628**	**-$ 926,694**	**$ 56,782**	**-$ 5,036,539**	**$ 19,018,497**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 926,694**			

CCA Class		Description	**Less:** *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 83,357
8		Stores Equipment	Stores Equipment	-$ 600
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 5,970
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 4,821
8		Communications Equipment	Communications Equipment	-$ 165
47		Deferred Revenue	Deferred Revenue	$ 51,039
		1253307.07	**Net Depreciation**	**-$ 882,819**

Table 2-23 – 2020 MIFRS Fixed Asset Continuity Schedule

Year 2020

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 406,769	$ 21,059	-$ 23,514	$ 404,315	-$ 315,481	-$ 29,488	$ 18,269	-$ 326,700	$ 77,614
CEC	1612	Land Rights (Formally known as Account 1906)	$ 135,718	$ 4,089	$ -	$ 139,807	$ -	$ -	$ -	$ -	$ 139,807
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 518,877	$ -	$ -	$ 518,877	-$ 213,859	-$ 30,792	$ -	-$ 244,651	$ 274,226
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,265,622	$ 214,652	-$ 16,938	$ 2,463,337	-$ 319,015	-$ 63,819	$ 3,752	-$ 379,082	$ 2,084,255
47	1835	Overhead Conductors & Devices	$ 2,264,991	$ 557,740	-$ 1,545	$ 2,821,186	-$ 229,592	-$ 49,760	$ 462	-$ 278,890	$ 2,542,296
47	1840	Underground Conduit	$ 4,385,586	$ 178,234	$ -	$ 4,563,821	-$ 474,838	-$ 99,233	$ -	-$ 574,071	$ 3,989,750
47	1845	Underground Conductors & Devices	$ 4,428,631	$ 144,008	$ -	$ 4,572,639	-$ 852,485	-$ 159,996	$ -	-$ 1,012,481	$ 3,560,158
47	1850	Line Transformers	$ 4,712,586	$ 424,239	-$ 58,743	$ 5,078,082	-$ 709,054	-$ 147,085	$ 12,937	-$ 843,203	$ 4,234,880
47	1855	Services (Overhead & Underground)	$ 1,619,431	$ 51,180	$ -	$ 1,670,611	-$ 237,683	-$ 52,690	$ -	-$ 290,373	$ 1,380,238
47	1860	Meters	$ 1,827,385	$ 74,360	-$ 18,049	$ 1,883,696	-$ 715,914	-$ 138,079	$ 6,923	-$ 847,069	$ 1,036,627
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 110,842	$ -	-$ 4,473	$ 106,368	$ -	$ -	$ -	$ -	$ 106,368
47	1908	Buildings & Fixtures	$ 1,959,121	$ 25,149	$ -	$ 1,984,270	-$ 475,138	-$ 83,677	$ -	-$ 558,815	$ 1,425,455
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 133,934	$ -	$ -	$ 133,934	-$ 70,514	-$ 12,158	$ -	-$ 82,672	$ 51,262
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 121,609	$ 44,717	-$ 4,101	$ 162,226	-$ 71,368	-$ 22,095	$ 2,394	-$ 91,069	$ 71,157
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 934,337	$ 181,741	-$ 70,204	$ 1,045,874	-$ 373,124	-$ 85,444	$ 60,893	-$ 397,674	$ 648,200
8	1935	Stores Equipment	$ 8,111	$ -	$ -	$ 8,111	-$ 5,832	-$ 481	$ -	-$ 6,313	$ 1,798
8	1940	Tools, Shop & Garage Equipment	$ 61,335	$ -	-$ 1,178	$ 60,157	-$ 30,311	-$ 5,424	$ 847	-$ 34,888	$ 25,269
8	1945	Measurement & Testing Equipment	$ 48,197	$ 3,769	-$ 424	$ 51,542	-$ 20,639	-$ 5,139	$ 325	-$ 25,453	$ 26,089
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,775	$ -	$ -	$ 1,775	-$ 908	-$ 165	$ -	-$ 1,073	$ 702
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 124,784	$ -	$ -	$ 124,784	-$ 99,569	-$ 7,590	$ -	-$ 107,159	$ 17,626
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 2,038,111	-$ 239,979	$ 4,458	-$ 2,273,632	$ 178,784	$ 54,748	$ -	$ 233,531	-$ 2,040,101
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 24,054,186**	**$ 1,684,959**	**-$ 194,710**	**$ 25,544,435**	**-$ 5,036,539**	**-$ 938,368**	**$ 106,802**	**-$ 5,868,105**	**$ 19,676,330**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 24,054,186**	**$ 1,684,959**	**-$ 194,710**	**$ 25,544,435**	**-$ 5,036,539**	**-$ 938,368**	**$ 106,802**	**-$ 5,868,105**	**$ 19,676,330**
		Construction Work In Progress	$ 850	$ 15,624		$ 16,474				$ -	$ 16,474
		Total PP&E	**$ 24,055,036**	**$ 1,700,583**	**-$ 194,710**	**$ 25,560,909**	**-$ 5,036,539**	**-$ 938,368**	**$ 106,802**	**-$ 5,868,105**	**$ 19,692,804**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 938,368**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 85,444
8		Stores Equipment	Stores Equipment	-$ 481
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 5,424
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 5,139
8		Communications Equipment	Communications Equipment	-$ 165
47		Deferred Revenue	Deferred Revenue	$ 54,748
		1684958.94	**Net Depreciation**	**-$ 896,463**

Table 2-24 – 2021 MIFRS Fixed Asset Continuity Schedule

Year 2021

			Cost				Accumulated Depreciation				
CCA Class [2]	OEB Account [3]	Description [3]	Opening Balance [8]	Additions [4]	Disposals [6]	Closing Balance	Opening Balance [8]	Additions	Disposals [6]	Closing Balance	Net Book Value
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 404,315	$ 22,675	-$ 137,596	$ 289,393	-$ 326,700	-$ 29,791	$ 136,942	-$ 219,549	$ 69,844
CEC	1612	Land Rights (Formally known as Account 1906)	$ 139,807	$ -	$ -	$ 139,807	$ -	$ -	$ -	$ -	$ 139,807
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 518,877	$ -	-$ 61,859	$ 457,017	-$ 244,651	-$ 25,004	$ 30,053	-$ 239,601	$ 217,416
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,463,337	$ 315,340	$ -	$ 2,778,677	-$ 379,082	-$ 68,822	$ -	-$ 447,904	$ 2,330,773
47	1835	Overhead Conductors & Devices	$ 2,821,186	$ 411,605	$ -	$ 3,232,791	-$ 278,890	-$ 57,713	$ -	-$ 336,603	$ 2,896,188
47	1840	Underground Conduit	$ 4,563,821	$ 365,650	$ -	$ 4,929,470	-$ 574,071	-$ 104,346	$ -	-$ 678,417	$ 4,251,054
47	1845	Underground Conductors & Devices	$ 4,572,639	$ 383,757	$ -	$ 4,956,396	-$ 1,012,481	-$ 167,554	$ -	-$ 1,180,035	$ 3,776,361
47	1850	Line Transformers	$ 5,078,082	$ 401,986	-$ 74,136	$ 5,405,933	-$ 843,203	-$ 157,686	$ 20,113	-$ 980,775	$ 4,425,157
47	1855	Services (Overhead & Underground)	$ 1,670,611	$ 135,998	$ -	$ 1,806,609	-$ 290,373	-$ 53,584	$ -	-$ 343,957	$ 1,462,651
47	1860	Meters	$ 1,883,696	$ 177,597	-$ 1,861	$ 2,059,431	-$ 847,069	-$ 142,511	$ 1,193	-$ 988,387	$ 1,071,044
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 106,368	$ -	$ -	$ 106,368	$ -	$ -	$ -	$ -	$ 106,368
47	1908	Buildings & Fixtures	$ 1,984,270	$ 5,633	$ -	$ 1,989,903	-$ 558,815	-$ 84,193	$ -	-$ 643,008	$ 1,346,895
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 133,934	$ -	$ -	$ 133,934	-$ 82,672	-$ 10,034	$ -	-$ 92,707	$ 41,228
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 162,226	$ 29,188	-$ 65,896	$ 125,518	-$ 91,069	-$ 23,891	$ 65,389	-$ 49,571	$ 75,947
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,045,874	$ -	$ -	$ 1,045,874	-$ 397,674	-$ 88,322	$ -	-$ 485,996	$ 559,878
8	1935	Stores Equipment	$ 8,111	$ -	$ -	$ 8,111	-$ 6,313	-$ 481	$ -	-$ 6,794	$ 1,317
8	1940	Tools, Shop & Garage Equipment	$ 60,157	$ 700	$ -	$ 60,856	-$ 34,888	-$ 4,854	$ -	-$ 39,742	$ 21,115
8	1945	Measurement & Testing Equipment	$ 51,542	$ 171	-$ 761	$ 50,952	-$ 25,453	-$ 4,966	$ 457	-$ 29,962	$ 20,989
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 1,775	$ 801	$ -	$ 2,576	-$ 1,073	-$ 172	$ -	-$ 1,245	$ 1,331
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 124,784	$ 7,024	-$ 1,826	$ 129,982	-$ 107,159	-$ 4,892	$ 1,613	-$ 110,438	$ 19,544
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue [5]	-$ 2,273,632	-$ 349,139	$ 5,524	-$ 2,617,247	$ 233,531	$ 61,687	$ 2	$ 295,220	-$ 2,322,027
	2005	Property Under Finance Lease [7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 25,544,435**	**$ 1,908,986**	**-$ 338,412**	**$ 27,115,008**	**-$ 5,868,105**	**-$ 967,130**	**$ 255,762**	**-$ 6,579,473**	**$ 20,535,536**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 25,544,435**	**$ 1,908,986**	**-$ 338,412**	**$ 27,115,008**	**-$ 5,868,105**	**-$ 967,130**	**$ 255,762**	**-$ 6,579,473**	**$ 20,535,536**
		Construction Work In Progress	$ 16,474	$ 21,677		$ 38,151				$ -	$ 38,151
		Total PP&E	**$ 25,560,909**	**$ 1,930,663**	**-$ 338,412**	**$ 27,153,160**	**-$ 5,868,105**	**-$ 967,130**	**$ 255,762**	**-$ 6,579,473**	**$ 20,573,687**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 967,130**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 88,322
8		Stores Equipment	Stores Equipment	-$ 481
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 4,854
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 4,966
8		Communications Equipment	Communications Equipment	-$ 172
47		Deferred Revenue	Deferred Revenue	$ 61,687
		1908985.98	**Net Depreciation**	**-$ 930,022**

Table 2-25 – 2022 MIFRS Fixed Asset Continuity Schedule

Year 2022

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 289,393	$ 25,735	-$ 43,526	$ 271,602	-$ 219,549	-$ 28,794	$ 42,789	-$ 205,554	$ 66,049
CEC	1612	Land Rights (Formally known as Account 1906)	$ 139,807	$ -	$ -	$ 139,807	$ -	$ -	$ -	$ -	$ 139,807
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 457,017	$ 4,394	$ -	$ 461,411	-$ 239,601	-$ 23,212	$ -	-$ 262,813	$ 198,598
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,778,677	$ 176,343	$ -	$ 2,955,020	-$ 447,904	-$ 74,285	$ -	-$ 522,189	$ 2,432,831
47	1835	Overhead Conductors & Devices	$ 3,232,791	$ 91,719	$ -	$ 3,324,510	-$ 336,603	-$ 61,907	$ -	-$ 398,510	$ 2,926,000
47	1840	Underground Conduit	$ 4,929,470	$ 1,625,359	$ -	$ 6,554,830	-$ 678,417	-$ 124,172	$ -	-$ 802,589	$ 5,752,241
47	1845	Underground Conductors & Devices	$ 4,956,396	$ 340,048	$ -	$ 5,296,444	-$ 1,180,035	-$ 183,858	$ -	-$ 1,363,893	$ 3,932,551
47	1850	Line Transformers	$ 5,405,933	$ 539,435	-$ 57,384	$ 5,887,985	-$ 980,775	-$ 165,148	$ 17,828	-$ 1,128,096	$ 4,759,889
47	1855	Services (Overhead & Underground)	$ 1,806,609	$ 50,731	$ -	$ 1,857,340	-$ 343,957	-$ 57,250	$ -	-$ 401,208	$ 1,456,132
47	1860	Meters	$ 2,059,431	$ 20,057	-$ 2,758	$ 2,076,731	-$ 988,387	-$ 146,266	$ 1,619	-$ 1,133,035	$ 943,696
47	1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
N/A	1905	Land	$ 106,368	$ -	$ -	$ 106,368	$ -	$ -	$ -	$ -	$ 106,368
47	1908	Buildings & Fixtures	$ 1,989,903	$ 38,033	$ -	$ 2,027,935	-$ 643,008	-$ 78,196	$ -	-$ 721,204	$ 1,306,731
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 133,934	$ 6,335	$ -	$ 140,269	-$ 92,707	-$ 8,881	$ -	-$ 101,588	$ 38,681
8	1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 125,518	$ 41,159	-$ 18,593	$ 148,084	-$ 49,571	-$ 25,840	$ 10,788	-$ 64,623	$ 83,461
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
10	1930	Transportation Equipment	$ 1,045,874	$ -	$ -	$ 1,045,874	-$ 485,996	-$ 88,322	$ -	-$ 574,319	$ 471,556
8	1935	Stores Equipment	$ 8,111	$ -	$ -	$ 8,111	-$ 6,794	-$ 399	$ -	-$ 7,193	$ 918
8	1940	Tools, Shop & Garage Equipment	$ 60,856	$ -	$ -	$ 60,856	-$ 39,742	-$ 4,403	$ -	-$ 44,145	$ 16,711
8	1945	Measurement & Testing Equipment	$ 50,952	$ 19,019	$ -	$ 69,970	-$ 29,962	-$ 5,953	$ -	-$ 35,916	$ 34,055
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 2,576	$ 2,243	$ -	$ 4,819	-$ 1,245	-$ 291	$ -	-$ 1,536	$ 3,284
8	1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 129,982	$ 2,399	$ -	$ 132,381	-$ 110,438	-$ 3,762	$ -	-$ 114,200	$ 18,181
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 2,617,247	-$ 62,566	$ -	-$ 2,679,813	$ 295,220	$ 66,647	$ -	$ 361,867	-$ 2,317,945
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 27,115,008**	**$ 2,920,445**	**-$ 122,260**	**$ 29,913,193**	**-$ 6,579,473**	**-$ 1,014,294**	**$ 73,024**	**-$ 7,520,743**	**$ 22,392,450**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 27,115,008**	**$ 2,920,445**	**-$ 122,260**	**$ 29,913,193**	**-$ 6,579,473**	**-$ 1,014,294**	**$ 73,024**	**-$ 7,520,743**	**$ 22,392,450**
		Construction Work In Progress	$ 38,151	-$ 3,084		$ 35,068				$ -	$ 35,068
		Total PP&E	**$ 27,153,160**	**$ 2,917,361**	**-$ 122,260**	**$ 29,948,260**	**-$ 6,579,473**	**-$ 1,014,294**	**$ 73,024**	**-$ 7,520,743**	**$ 22,427,518**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,014,294**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 88,322
8		Stores Equipment	Stores Equipment	-$ 399
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 4,403
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 5,953
8		Communications Equipment	Communications Equipment	-$ 291
47		Deferred Revenue	Deferred Revenue	$ 66,647
		2920444.58	**Net Depreciation**	**-$ 981,573**

Table 2-26 – 2023 MIFRS Fixed Asset Continuity Schedule

Year **2023**

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	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)	$ 271,602	$ 15,525	$ -	$ 287,127	-$ 205,554	-$ 27,080	$ -	-$ 232,634	$ 54,494
CEC	1612	Land Rights (Formally known as Account 1906)	$ 139,807			$ 139,807	$ -			$ -	$ 139,807
N/A	1805	Land	$ 22,655			$ 22,655	$ -			$ -	$ 22,655
47	1808	Buildings	$ -			$ -	$ -			$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 461,411	$ -	$ -	$ 461,411	-$ 262,813	-$ 23,258	$ -	-$ 286,072	$ 175,340
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,955,020	$ 131,780	-$ 6,600	$ 3,080,200	-$ 522,189	-$ 77,615	$ 600	-$ 599,205	$ 2,480,995
47	1835	Overhead Conductors & Devices	$ 3,324,510	$ 95,898	-$ 4,400	$ 3,416,008	-$ 398,510	-$ 63,434	$ 400	-$ 461,544	$ 2,954,464
47	1840	Underground Conduit	$ 6,554,830	$ 465,369	$ -	$ 7,020,199	-$ 802,589	-$ 144,303	$ -	-$ 946,892	$ 6,073,307
47	1845	Underground Conductors & Devices	$ 5,296,444	$ 489,513	$ -	$ 5,785,957	-$ 1,363,893	-$ 188,332	$ -	-$ 1,552,225	$ 4,233,732
47	1850	Line Transformers	$ 5,887,985	$ 896,339	-$ 17,000	$ 6,767,324	-$ 1,128,096	-$ 182,551	$ 2,000	-$ 1,308,647	$ 5,458,677
47	1855	Services (Overhead & Underground)	$ 1,857,340	$ 95,951	$ -	$ 1,953,290	-$ 401,208	-$ 59,559	$ -	-$ 460,767	$ 1,492,523
47	1860	Meters	$ 2,076,731	$ 205,289	-$ 18,800	$ 2,263,220	-$ 1,133,035	-$ 152,720	$ 2,200	-$ 1,283,555	$ 979,665
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 106,368	$ -	$ -	$ 106,368	$ -	$ -	$ -	$ -	$ 106,368
47	1908	Buildings & Fixtures	$ 2,027,935	$ 75,801	-$ 440	$ 2,103,296	-$ 721,204	-$ 73,750	$ 40	-$ 794,915	$ 1,308,382
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 140,269	$ 5,000	$ -	$ 145,269	-$ 101,588	-$ 7,337	$ -	-$ 108,925	$ 36,344
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
10	1920	Computer Equipment - Hardware	$ 148,084	$ 11,695	-$ 4,000	$ 155,779	-$ 64,623	-$ 28,127	$ 3,000	-$ 89,750	$ 66,029
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,045,874	$ -	-$ 5,000	$ 1,040,874	-$ 574,319	-$ 85,858	$ -	-$ 660,176	$ 380,698
8	1935	Stores Equipment	$ 8,111	$ 2,000	$ -	$ 10,111	-$ 7,193	-$ 354	$ -	-$ 7,547	$ 2,564
8	1940	Tools, Shop & Garage Equipment	$ 60,856	$ 2,000	$ -	$ 62,856	-$ 44,145	-$ 4,330	$ -	-$ 48,475	$ 14,381
8	1945	Measurement & Testing Equipment	$ 69,970	$ 2,778	$ -	$ 72,749	-$ 35,916	-$ 6,211	$ -	-$ 42,127	$ 30,622
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 4,819	$ 7,584	$ -	$ 12,403	-$ 1,536	-$ 1,098	$ -	-$ 2,634	$ 9,770
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -		$ -	$ -	$ -
8	1960	Miscellaneous Equipment	$ 132,381	$ 2,000	$ -	$ 134,381	-$ 114,200	-$ 3,779	$ -	-$ 117,979	$ 16,402
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 2,679,813	-$ 451,067	$ -	-$ 3,130,879	$ 361,867	$ 72,496	$ -	$ 434,363	-$ 2,696,516
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 29,913,193**	**$ 2,053,455**	**-$ 56,240**	**$ 31,910,408**	**-$ 7,520,743**	**-$ 1,057,203**	**$ 8,240**	**-$ 8,569,706**	**$ 23,340,702**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 29,913,193**	**$ 2,053,455**	**-$ 56,240**	**$ 31,910,408**	**-$ 7,520,743**	**-$ 1,057,203**	**$ 8,240**	**-$ 8,569,706**	**$ 23,340,702**
		Construction Work In Progress	$ 35,068	-$ 35,067		$ 0				$ -	$ 0
		Total PP&E	**$ 29,948,260**	**$ 2,018,388**	**-$ 56,240**	**$ 31,910,408**	**-$ 7,520,743**	**-$ 1,057,203**	**$ 8,240**	**-$ 8,569,706**	**$ 23,340,703**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,057,203**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 85,858
8		Stores Equipment	Stores Equipment	-$ 354
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 4,330
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 6,211
8		Communications Equipment	Communications Equipment	-$ 1,098
47		Deferred Revenue	Deferred Revenue	$ 72,496
		2053455.497	**Net Depreciation**	**-$ 1,031,848**

Table 2-27 – 2024 MIFRS Fixed Asset Continuity Schedule

Year 2024

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 287,127	$ 197,380	$ -	$ 484,507	-$ 232,634	-$ 42,045	$ -	-$ 274,678	$ 209,829
CEC	1612	Land Rights (Formally known as Account 1906)	$ 139,807			$ 139,807	$ -			$ -	$ 139,807
N/A	1805	Land	$ 22,655	$ -	$ -	$ 22,655	$ -	$ -	$ -	$ -	$ 22,655
47	1808	Buildings	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
13	1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 461,411	$ 7,194	$ -	$ 468,605	-$ 286,072	-$ 21,171	$ -	-$ 307,243	$ 161,363
47	1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,080,200	$ 147,900	-$ 6,600	$ 3,221,500	-$ 599,205	-$ 80,668	$ 600	-$ 679,273	$ 2,542,227
47	1835	Overhead Conductors & Devices	$ 3,416,008	$ 227,478	-$ 4,400	$ 3,639,086	-$ 461,544	-$ 66,145	$ 400	-$ 527,290	$ 3,111,797
47	1840	Underground Conduit	$ 7,020,199	$ 673,960	$ -	$ 7,694,159	-$ 946,892	-$ 155,070	$ -	-$ 1,101,962	$ 6,592,196
47	1845	Underground Conductors & Devices	$ 5,785,957	$ 511,536	$ -	$ 6,297,493	-$ 1,552,225	-$ 200,213	$ -	-$ 1,752,438	$ 4,545,055
47	1850	Line Transformers	$ 6,767,324	$ 793,138	-$ 17,000	$ 7,543,462	-$ 1,308,647	-$ 207,529	$ 2,000	-$ 1,514,176	$ 6,029,286
47	1855	Services (Overhead & Underground)	$ 1,953,290	$ 353,578	$ -	$ 2,306,869	-$ 460,767	-$ 65,268	$ -	-$ 526,035	$ 1,780,834
47	1860	Meters	$ 2,263,220	$ 251,499	-$ 18,800	$ 2,495,919	-$ 1,283,555	-$ 161,729	$ 2,200	-$ 1,443,084	$ 1,052,835
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ 106,368	$ -	$ -	$ 106,368	$ -	$ -	$ -	$ -	$ 106,368
47	1908	Buildings & Fixtures	$ 2,103,296	$ 296,000	-$ 440	$ 2,398,856	-$ 794,915	-$ 81,209	$ 40	-$ 876,084	$ 1,522,773
13	1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 145,269	$ 30,000	$ -	$ 175,269	-$ 108,925	-$ 8,139	$ -	-$ 117,064	$ 58,205
8	1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 155,779	$ 58,000	-$ 4,000	$ 209,779	-$ 89,750	-$ 31,318	$ 3,000	-$ 118,068	$ 91,711
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -			$ -	$ -
10	1930	Transportation Equipment	$ 1,040,874	$ 93,815	$ -	$ 1,134,689	-$ 660,176	-$ 81,489	$ -	-$ 741,665	$ 393,024
8	1935	Stores Equipment	$ 10,111	$ 2,000	$ -	$ 12,111	-$ 7,547	-$ 490	$ -	-$ 8,037	$ 4,074
8	1940	Tools, Shop & Garage Equipment	$ 62,856	$ 6,500	$ -	$ 69,356	-$ 48,475	-$ 4,431	$ -	-$ 52,906	$ 16,450
8	1945	Measurement & Testing Equipment	$ 72,749	$ 24,222	$ -	$ 96,971	-$ 42,127	-$ 7,038	$ -	-$ 49,165	$ 47,806
8	1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
8	1955	Communications Equipment	$ 12,403	$ 1,000	$ -	$ 13,403	-$ 2,634	-$ 1,856	$ -	-$ 4,490	$ 8,914
8	1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 134,381	$ 2,000	$ -	$ 136,381	-$ 117,979	-$ 3,736	$ -	-$ 121,715	$ 14,666
47	1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
47	1995	Contributions & Grants	$ -		$ -	$ -	$ -		$ -	$ -	$ -
47	2440	Deferred Revenue[5]	-$ 3,130,879	-$ 718,936	$ -	-$ 3,849,816	$ 434,363	$ 85,531	$ -	$ 519,894	-$ 3,329,922
	2005	Property Under Finance Lease[7]	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
		Sub-Total	**$ 31,910,408**	**$ 2,958,264**	**-$ 51,240**	**$ 34,817,432**	**-$ 8,569,706**	**-$ 1,134,013**	**$ 8,240**	**-$ 9,695,478**	**$ 25,121,953**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 31,910,408**	**$ 2,958,264**	**-$ 51,240**	**$ 34,817,432**	**-$ 8,569,706**	**-$ 1,134,013**	**$ 8,240**	**-$ 9,695,478**	**$ 25,121,953**
		Construction Work In Progress	$ 0	$ -		$ 0				$ -	$ 0
		Total PP&E	**$ 31,910,408**	**$ 2,958,264**	**-$ 51,240**	**$ 34,817,432**	**-$ 8,569,706**	**-$ 1,134,013**	**$ 8,240**	**-$ 9,695,478**	**$ 25,121,954**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,134,013**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 81,489
8		Stores Equipment	Stores Equipment	-$ 490
8		Tools, Shop & Garage Equipment	Tools, Shop & Garage Equipment	-$ 4,431
8		Measurement & Testing Equipment	Measurement & Testing Equipme	-$ 7,038
8		Communications Equipment	Communications Equipment	-$ 1,856
47		Deferred Revenue	Deferred Revenue	$ 85,531
		2958264.013	**Net Depreciation**	**-$ 1,124,239**

2.2.2 GROSS ASSET BREAKDOWN BY FUNCTION

Table 2-28 – OEB Appendix 2-AB Capital Expenditures from DSP summarizes the gross capital additions of assets for the:

- 2014 expired distribution system plan ("DSP") for the period 2014 to 2018.
- OHL Board of director-approved budget for 2019 and 2020 due to expired DSP.
- 2021 DSP for 2021 to 2023.
- 2024 DSP for the forecast period of 2024 to 2028.

Table 2-28 – OEB Appendix 2-AB Capital Expenditures from DSP

Appendix 2-AB

Table 2 - Capital Expenditure Summary from Chapter 5 Consolidated Distribution System Plan Filing Requirements

First year of Forecast Period:
2024

Historical Period (previous plan[1] & actual)

CATEGORY	2014 Plan	2014 Actual	2014 Var	2015 Plan	2015 Actual	2015 Var	2016 Plan	2016 Actual	2016 Var	2017 Plan	2017 Actual	2017 Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	411	941	129.0%	457	264	-42.2%	411	1,088	164.7%	457	1,656	262.4%
System Renewal	525	306	-41.7%	125	237	89.6%	212	252	18.9%	-	248	--
System Service	595	413	-30.6%	468	601	28.4%	545	434	-20.4%	751	520	-30.8%
General Plant	494	507	2.6%	377	191	-49.3%	234	168	-28.2%	86	128	48.8%
TOTAL EXPENDITURE	2,025	2,167	7.0%	1,427	1,293	-9.4%	1,402	1,942	38.5%	1,294	2,552	97.2%
Capital Contributions	- 298	- 538	80.5%	- 298	- 200	-32.9%	- 298	- 397	33.2%	- 298	- 634	112.8%
NET CAPITAL EXPENDITURES	1,727	1,629	-6%	1,129	1,093	-3%	1,104	1,545	40%	996	1,918	93%
System O&M	$ 1,124	$ 919	-18.2%	$ 1,141	$ 962	-15.7%	$ 1,158	$ 907	-21.7%	$ 1,175	$ 989	-15.8%

CATEGORY	2018 Plan	2018 Actual	2018 Var	2019 Plan	2019 Actual	2019 Var	2020 Plan	2020 Actual	2020 Var	2021 Plan	2021 Actual	2021 Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	457	510	11.6%	624	303	-51.4%	609	373	-38.8%	315	737	134.0%
System Renewal	33	201	509.1%	267	218	-18.4%	190	395	107.9%	791	530	-33.0%
System Service	709	626	-11.7%	535	676	26.4%	1,005	877	-12.7%	868	925	6.6%
General Plant	152	451	196.7%	316	171	-45.9%	424	280	-34.0%	102	66	-35.3%
TOTAL EXPENDITURE	1,351	1,788	32.3%	1,742	1,368	-21.5%	2,228	1,925	-13.6%	2,076	2,258	8.8%
Capital Contributions	- 298	- 206	-30.9%	- 286	- 115	-59.8%	- 244	- 240	-1.6%	- 205	- 349	70.2%
NET CAPITAL EXPENDITURES	1,053	1,582	50%	1,456	1,253	-14%	1,984	1,685	-15%	1,871	1,909	2%
System O&M	$ 1,193	$ 755	-36.7%	$ 1,001	$ 959	-4.2%	$ 1,002	$ 808	-19.4%	$ 1,112	$ 1,078	-3.1%

Forecast Period (planned)

CATEGORY	2022 Plan	2022 Actual	2022 Var	2023 Plan	2023 Actual[2]	2023 Var	2024	2025	2026	2027	2028
	$ '000		%	$ '000		%	$ '000				
System Access	428	96	-77.6%	820	820	0.0%	1,360	659	688	650	866
System Renewal	541	554	2.4%	583	583	0.0%	787	720	817	738	807
System Service	1,095	2,198	100.7%	977	977	0.0%	819	1,194	1,405	1,359	1,557
General Plant	213	135	-36.6%	124	124	0.0%	711	436	215	490	225
TOTAL EXPENDITURE	2,277	2,983	31.0%	2,504	2,504	0.0%	3,677	3,009	3,125	3,237	3,455
Capital Contributions	- 203	- 63	-69.0%	- 451	- 451	0.0%	- 719	204	- 378	- 292	- 372
NET CAPITAL EXPENDITURES	2,074	2,920	41%	2,053	2,053	0%	2,958	3,213	2,747	2,945	3,083
System O&M	$ 1,134	$ 1,164	2.7%	$ 1,249	$ 1,249	0.0%	$ 1,359	$ 1,393	$ 1,379	$ 1,170	$ 1,199

The gross asset breakdown by function can be found in the following 2 tables.

The 2014 Board Approved gross assets and accumulated depreciation seem out of line with the 2014 to 2024 Test year. As OHL netted the accumulated depreciation with asset cost effective January 1, 2014, the net book values are consistent across the whole period from last CoS to 2024 Test Year.

1 ## Table 2-29 – Gross Asset Breakdown by Function 2014-2018

Gross Assets	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS
Distribution Equipment	33,261,573	14,120,075	15,128,153	16,804,209	19,156,777	20,417,174
Land and Buildings	1,046,867	559,268	521,834	590,821	619,464	634,305
Vehicles	1,303,069	540,921	592,540	672,567	665,088	913,299
Computer Assets	1,065,533	401,846	377,246	417,508	438,380	458,651
Operating Building	3,000,585	1,935,680	1,990,630	1,991,605	1,964,684	2,034,434
Other Assets	636,632	237,454	267,479	291,785	316,865	368,316
Contributed Capital	(4,772,809)	(538,014)	(732,709)	(1,128,498)	(1,762,460)	(1,968,172)
Total	**$ 35,541,450**	**$ 17,257,229**	**$ 18,145,173**	**$19,639,998**	**$ 21,398,798**	**$ 22,858,007**
WIP	-	45,233	26,360	14,008	23,029	29,360
Total with WIP	**$ 35,541,450**	**$ 17,302,462**	**$ 18,171,533**	**$19,654,006**	**$ 21,421,827**	**$ 22,887,367**

Accumulated Depreciation	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS
Distribution Equipment	16,456,101	542,488	1,101,792	1,657,366	2,251,467	2,886,852
Land and Buildings	642,944	39,329	79,827	111,957	144,806	178,931
Vehicles	829,393	52,121	121,353	190,600	243,207	301,551
Computer Assets	822,922	124,939	166,542	243,858	287,721	336,271
Operating Building	1,126,259	76,432	154,315	233,575	312,778	393,045
Other Assets	410,337	37,807	76,247	117,426	157,999	199,725
Contributed Capital	(1,386,287)	(6,962)	(22,439)	(45,869)	(82,382)	(129,749)
Total	**$ 18,901,670**	**$ 866,154**	**$ 1,677,637**	**$ 2,508,912**	**$ 3,315,596**	**$ 4,166,627**

Net Book Value	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS
Distribution Equipment	16,805,471	13,577,587	14,026,361	15,146,843	16,905,310	17,530,321
Land and Buildings	403,923	519,938	442,007	478,864	474,658	455,374
Vehicles	473,676	488,800	471,187	481,967	421,881	611,748
Computer Assets	242,611	276,906	210,704	173,651	150,659	122,380
Operating Building	1,874,326	1,859,248	1,836,315	1,758,030	1,651,906	1,641,390
Other Assets	226,295	199,647	191,231	174,360	158,866	168,591
Contributed Capital	(3,386,522)	(531,052)	(710,270)	(1,082,629)	(1,680,078)	(1,838,424)
Total	**$ 16,639,780**	**$ 16,391,075**	**$ 16,467,536**	**$17,131,085**	**$ 18,083,203**	**$ 18,691,380**
WIP	-	45,233	26,360	14,008	23,029	29,360
Total with WIP	**$ 16,639,780**	**$ 16,436,308**	**$ 16,493,895**	**$17,145,094**	**$ 18,106,232**	**$ 18,720,740**

2

1 **Table 2-30 – Gross Asset Breakdown by Function 2019-2024**

Gross Assets	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Distribution Equipment	21,504,232	23,053,372	25,169,308	27,952,860	30,286,199	33,198,488
Land and Buildings	677,250	681,339	619,480	623,874	623,874	631,068
Vehicles	934,337	1,045,874	1,045,874	1,045,874	1,040,874	1,134,689
Computer Assets	528,378	566,540	414,911	419,687	442,907	694,287
Operating Building	2,069,963	2,090,638	2,096,271	2,134,304	2,209,665	2,505,225
Other Assets	378,137	380,303	386,411	416,407	437,769	503,491
Contributed Capital	(2,038,111)	(2,273,632)	(2,617,247)	(2,679,813)	(3,130,879)	(3,849,816)
Total	**$ 24,054,186**	**$ 25,544,435**	**$ 27,115,008**	**$ 29,913,193**	**$ 31,910,408**	**$ 34,817,432**
WIP	849	16,474	38,151	35,067	(0)	(0)
Total with WIP	**$ 24,055,036**	**$ 25,560,909**	**$ 27,153,159**	**$ 29,948,260**	**$ 31,910,408**	**$ 34,817,432**

Accumulated Depreciation	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Distribution Equipment	3,538,580	4,225,169	4,956,079	5,749,519	6,612,835	7,544,257
Land and Buildings	213,859	244,651	239,601	262,813	286,072	307,243
Vehicles	373,124	397,674	485,996	574,319	660,176	741,665
Computer Assets	386,849	417,769	269,120	270,177	322,384	392,746
Operating Building	475,138	558,815	643,008	721,204	794,915	876,084
Other Assets	227,773	257,558	280,888	304,577	327,687	353,377
Contributed Capital	(178,784)	(233,532)	(295,220)	(361,868)	(434,363)	(519,894)
Total	**$ 5,036,538**	**$ 5,868,104**	**$ 6,579,472**	**$ 7,520,742**	**$ 8,569,705**	**$ 9,695,478**

Net Book Value	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Distribution Equipment	17,965,653	18,828,203	20,213,228	22,203,341	23,673,364	25,654,231
Land and Buildings	463,391	436,688	379,878	361,060	337,802	323,825
Vehicles	561,214	648,200	559,878	471,556	380,698	393,024
Computer Assets	141,529	148,772	145,791	149,510	120,523	301,540
Operating Building	1,594,825	1,531,824	1,453,263	1,413,100	1,414,750	1,629,141
Other Assets	150,364	122,745	105,524	111,830	110,082	150,114
Contributed Capital	(1,859,327)	(2,040,101)	(2,322,027)	(2,317,945)	(2,696,516)	(3,329,922)
Total	**$ 19,017,648**	**$ 19,676,331**	**$ 20,535,536**	**$ 22,392,450**	**$ 23,340,703**	**$ 25,121,954**
WIP	849	16,474	38,151	35,067	(0)	(0)
Total with WIP	**$ 19,018,497**	**$ 19,692,804**	**$ 20,573,687**	**$ 22,427,518**	**$ 23,340,703**	**$ 25,121,954**

2.2.3 GROSS ASSET BREAKDOWN BY OEB CATEGORY

The table below summarizes the gross capital additions of assets for the historical years 2014 to 2022, and the forecasted 2023 Bridge year and 2024 Test year.

Table 2-31 – Gross Asset Breakdown by OEB Category

Category	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
System Access (Gross)	411,106	940,972	263,560	1,088,050	1,655,660	509,508	302,685	372,926	736,527	96,413	820,036	1,359,889
System Renewal (Gross)	525,050	305,569	236,946	251,590	248,552	201,614	217,629	394,476	530,019	554,050	583,185	787,454
System Service (Gross)	595,456	413,471	601,128	433,835	519,849	625,952	676,650	877,012	925,386	2,197,624	976,919	818,940
General Plant (Gross)	493,500	507,152	191,473	167,516	127,549	443,852	171,264	280,525	66,192	134,922	124,383	710,917
Gross Capital Expenses	**2,025,112**	**2,167,163**	**1,293,107**	**1,940,991**	**2,551,610**	**1,780,926**	**1,368,228**	**1,924,938**	**2,258,125**	**2,983,010**	**2,504,522**	**3,677,200**
Contributed Capital	(298,474)	(538,014)	(200,284)	(395,789)	(633,962)	(198,868)	(114,921)	(239,979)	(349,139)	(62,566)	(451,067)	(718,936)
Net Capital Expenses	**$ 1,726,638**	**$ 1,629,149**	**$ 1,092,823**	**$ 1,545,201**	**$ 1,917,648**	**$ 1,582,058**	**$ 1,253,307**	**$ 1,684,959**	**$ 1,908,986**	**$ 2,920,445**	**$ 2,053,455**	**$ 2,958,264**

<u>System Access</u>

System access investments are modifications (including asset relocation) to a distributor's distribution system that a distributor is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via the distribution system.

System access expenditures for 2023 to 2024 are expected to be higher than the historical average of 2014 to 2022 due to large subdivisions anticipated and an increased cost of materials relative to historical trends. System Access projects encompass customer requests for service connections and subdivisions. Growth will occur from new subdivisions, infill developments, and intensification developments. Considering these expenditures are based on customer demand, this forecast is subject to change.

In 2023, the increase in subdivisions is driven by the fact that 62A-68 First Street, Mayberry Hill Phase 3A Block 43 and 670-690 Broadway have been energized in 2023.

In 2024, the increase in subdivision is driven by large subdivisions. Edgewood Valley Developments Phase 2B is a detached home development which is much larger than OHL's typical subdivision connection projects. Another Grand Valley detached home development is expected to be energized and has been confirmed to OHL by the developers.

The gross system access additions from 2014 to 2024 have averaged $740K and the net system access additions have averaged $386K. These types of expenditures are non-discretionary in nature and are initiated by customers or other authorities. System expansion requirements from Renewable Energy Generation have not occurred nor are they expected to occur in the near future. Specifics can be found in the Distribution System Plan at Appendix 2-A.

Table 2-32 – System Access Additions

Projects	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 Bridge Year	2024 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access											
S01-20xx Subdivisions	711,739	188,315	997,994	1,580,448	388,879	250,571	232,893	436,731	16,970	675,655	1,241,889
C01-20xx General Service Projects	130,726	47,711	62,978	34,998	84,540	40,838	102,960	199,565	51,415	121,793	80,000
C02-20xx Residential Service Projects	71,836	16,709	19,846	37,208	19,771	11,276	37,073	16,428	22,941	21,543	30,000
C03-20xx Road Widening Projects	-	-	-	-	-	-	-	83,802	4,120	1,044	
F01-20xx Embedded Generation Projects >10kW	7,831	6,303	5,105	2,464	10,917	-	-	-	968		8,000
F02-20xx Embedded Generation Projects (<10 kW)	18,839	4,522	2,127	542	5,400	-	-	-	-		
System Access Gross Expenditures	**940,972**	**263,560**	**1,088,050**	**1,655,660**	**509,508**	**302,685**	**372,926**	**736,527**	**96,413**	**820,036**	**1,359,889**
System Access Capital Contributions	- 538,014	- 200,284	- 395,789	- 633,962	- 198,868	- 114,921	- 239,979	- 349,139	- 62,566	- 451,067	- 718,936
Sub-Total	402,958	63,276	692,260	1,021,698	310,640	187,764	132,947	387,388	33,847	368,969	640,953

System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and are required to maintain the ability of the distribution system to provide customers with electricity services. The gross system access additions from 2014 to 2024 have averaged $392K.

System renewal expenditures for 2023 to 2024 are expected to be higher than the historical average of 2014 to 2022 due to an increased cost of materials relative to historical trends. These expenditures are to improve the distribution system by either replacing assets or extending the original service life of the major assets such as poles, transformers, switches, switching cubicles, and revenue meters. Considering these expenditures can be affected by the quantity of major assets that fail in a specific year, this forecast is subject to change. Specifics can be found in the Distribution System Plan in Appendix 2-C.

The increase in expenditures is due to planned replacements of meters, as OHL's whole meter population requires replacement or reverification by 2028. A new automatic sleeve replacement program is required to address an increase in failures over the historical period. A new PME replacement program is addressing defective equipment issues due to PME failures.

Table 2-33 – System Renewal Additions

Projects	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 Bridge Year	2024 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Renewal											
B79-2014 Parkview Heights Tx Replacement	73,228	-	-	-	-	-	-	-	-		
B80-2014 Emma & Douglas pole Replacement	51,449	-	-	-	-	-	-	-	-		
B00-20xx Transformer Replacements	27,205	41,398	36,051	79,444	- 14,411	101,183	269,862	94,505	122,994	171,328	161,383
H00-20xx Major Component Replacements	5,720	14,766	21,349	11,149	18,593	-	94,781	59,959	32,577	142,164	227,478
M00-20xx Meter Replacements	34,336	60,363	65,516	91,795	125,656	108,566	-	171,001	19,089	121,793	243,499
P00-20xx Pole Replacements	15,681	18,940	48,465	66,163	71,776	7,880	29,832	139,456	104,151	147,900	147,900
Other Projects	97,951	49,891	40,612	-	-	-	-	-	-		
B115-2021 39 Main st S Pole Line Rebuild	-	-	-	-	-	-	-	65,098	-		
B52-2022 Replace Navicom Box	-	-	-	-	-	-	-	-	2,445		
B81-2014 West Broadway 27.6 kV UG Conversion	-	51,586	39,597	-	-	-	-	-	-		
B83-2022 Municipal Substation Major Service	-	-	-	-	-	-	-	-	4,394		7,194
B117-2022 Rail Line Pole Renewal	-	-	-	-	-	-	-	-	268,399		
System Renewal Gross Expenditures	**305,569**	**236,946**	**251,590**	**248,552**	**201,614**	**217,629**	**394,476**	**530,019**	**554,050**	**583,185**	**787,454**
System Renewal Capital Contributions											
Sub-Total	**305,569**	**236,946**	**251,590**	**248,552**	**201,614**	**217,629**	**394,476**	**530,019**	**554,050**	**583,185**	**787,454**

System Service

System service investments encompass modifications to an LDC's distribution system to ensure the distribution system continues to meet distributor operational requirements while addressing anticipated future customer electricity service requirements. The gross system service additions from 2014 to 2024 have averaged $824K.

System service expenditures for 2023 to 2024 are expected to be higher than the historical average of 2014 to 2022 due to an increased cost of materials relative to historical trends. These projects are planned to ensure the distribution system continues to meet operational objectives, while addressing future needs. The expenditures within this 5-year plan are significantly driven by OHL's voltage conversion program. These expenditures are to improve the distribution system by either replacing assets or extending the original service life of the major assets such as poles, transformers, switches, switching cubicles, and revenue meters. Considering these expenditures can be affected by the quantity of major assets that fail in a specific year, this forecast is subject to change. Specifics can be found in the Distribution System Plan in Appendix 2-C.

Table 2-34 – System Service Additions

Projects	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 Bridge Year	2024 Test Year	2025	2026	2027	2028
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Service															
B48-2012 Centre & Church St Conversion	26,770	-	-	-	-	-	-	-	-						
B78-2014 Water & William St U/G Conversion	11,215	245,587	-	-	-	-	-	-	-						
B85-2013 Bythia-Victoria-Princess 27.6kV Conversion	331,422	-	-	-	-	-	-	-	-						
B85-2015 Centre & Church St Conversion	-	337,885	-	-	-	-	-	-	-						
Various Projects < $50,000	44,065	17,656	32,433	-	-	-	-	-	-						
B88-2014 10 Third St 27.6 kV Conversion	-	-	60,073	-	-	-	-	-	-						
B98-2016 M23 Feeder - Upstream Upgrade	-	-	79,304	-	-	-	-	-	-						
B99-2016 Riddell Rd Feeder Tie	-	-	112,767	-	-	-	-	-	-						
B78-2016 First St 27KV Conversion	-	-	149,257	-	-	-	-	-	-						
B89-2017 Paint Single Phase PDMT tx's	-	-	-	15,092	-	-	-	-	-						
B98-2017 M23 Feeder Connection and Integration	-	-	-	82,468	-	-	-	-	-						
B99-2017 Riddell Rd Feeder Tie	-	-	-	6,872	-	-	-	-	-						
B102-2017 Third St (Broadway to Fifth ave) 27.6 kv Conv	-	-	-	105,086	-	-	-	-	-						
B103-2017 East Broadway (Third st to Townline)Voltage (	-	-	-	88,853	-	-	-	-	-						
B104-2017 Scattered Voltage Conversion (Dawson/Hillsid	-	-	-	107,320	-	-	-	-	-						
B105-2017 Ms4-E Feeder (East of Faulkner) Voltage Co	-	-	-	114,159	-	-	-	-	-						
B83-2018 Municipal Substation Major Svc	-	-	-	-	7,026	-	-	-	-						
B98-2018 M23 Feeder - Upstream Upgrades	-	-	-	-	28,879	-	-	-	-						
B99-2018 Riddell Rd Feeder Tie	-	-	-	-	43,835	-	-	-	-						
B105-2018 Ms4-E Feeder(East of Faulkner)	-	-	-	-	546,213	-	-	-	-						
B76-2019 Stoney Cres	-	-	-	-	-	3,906	-	-	-						
B83-2019 Municipal Substation Major svc	-	-	-	-	-	10,805	-	-	-						
B99-2019 Riddell Rd Feeder Tie	-	-	-	-	-	143,889	-	-	-						
B105-2019 MS4-E Feeder (East of Faulkner)	-	-	-	-	-	8,591	-	-	-						
B108-2019 Main St GV pole rebuild	-	-	-	-	-	50,006	-	-	-						
B109-2019 27.6kv Conversion 3rd st - 2nd st	-	-	-	-	-	140,998	509,219	-	-						
B110-2019 Riddell Rd Feeder Tie	-	-	-	-	-	318,455	-	-	-						
B111-2020 Elizabeth/McCarthy Conversion	-	-	-	-	-	-	228,336	-	-						
B112-2020 Riddell Road Feeder Tie	-	-	-	-	-	-	68,400	-	-						
B110-2021 Second Ave to Elizabeth St 27.6 kV Conversi	-	-	-	-	-	-	-	3,154	-						
B113-2020 Robb Blvd Conversion	-	-	-	-	-	-	71,058	-	-						
B111-2021 Elizabeth/McCarthy Conversion	-	-	-	-	-	-	-	21,440	-						
B112-2021 Broadway/Ada Conversion	-	-	-	-	-	-	-	3,123	-						
B113-2021 MS2 -West Feeder (Robb Blvd & 100 Century	-	-	-	-	-	-	-	626,423	-						
B114-2021 Centennial Rd Rebuild	-	-	-	-	-	-	-	160,327	-						
B116-2021 MS3-East Feeder (Hillside Dr) Conversion	-	-	-	-	-	-	-	110,920	-						
B117-2023 Rail Line Pole Renewal										87,960					
B118-2022 MS 2 South Feeder Conversion PV-MC-HD-N	-	-	-	-	-	-	-	-	1,110,209						
B120-2022 MS2 South Feeder Voltage Conversion-Edelw	-	-	-	-	-	-	-	-	491,629	366,687					
B122-2022 MS2 South Feeder Voltage Conversion-Edelw	-	-	-	-	-	-	-	-	595,787	522,092	209,941				
B124-2023 MS2 Feeder Ontario/Victoria Voltage Conversion										180					
B121-2024 MS2 East Feeder Voltage Conversion-Maple/Madison Ave											419,902				
B2024-1-2024 Ontario and Victoria Street Voltage Conversion											189,097				
B119-2025 Blind Line Primary Conductor Upgrade-Broadway to Hansen												206,345			
B123-2025 Voltage Conversion from Rabbit-Cardwell-Dufferin-Ontario-Caledonia												577,878			
B124-2025 MS2 East Feeder Conversion-Carlton-Lawrence												409,955			
B125-2026 MS3 North Feeder - Broadway-Banting-Zina-Elizabeth-Birch Conversion													882,704		
B126-2026 MS4 West Feeder - Amelia St-Jackson Crt Voltage Conversion													522,423		
B127-2027 MS4 West Feeder - Meadow, Passmore, Pheasant Dr Voltage Conversion														805,985	537,323
B128-2027 MS4 West Feeder - Westmorland-Fairview,Elm Voltage Conversion														553,265	
B129-2028 MS4 West Feeder - Kensington Place Voltage Conversion															663,065
BRAB-2028 Voltage Converstion of Rabbits (Crimson, Orangemill, Quarry, Sherbourne)															356,627
System Service Gross Expenditures	**413,471**	**601,128**	**433,835**	**519,849**	**625,952**	**676,650**	**877,012**	**925,386**	**2,197,624**	**976,919**	**818,940**	**1,194,177**	**1,405,127**	**1,359,250**	**1,557,016**
System Service Capital Contributions															
Sub-Total	**413,471**	**601,128**	**433,835**	**519,849**	**625,952**	**676,650**	**877,012**	**925,386**	**2,197,624**	**976,919**	**818,940**	**1,194,177**	**1,405,127**	**1,359,250**	**1,557,016**

General Plant

General plant investments encompass modifications, replacements or additions to a distributor's assets that are not part of its distribution system including land and buildings, tools and equipment, vehicles and electronic devices and software used to support day to day business and operations activities. Intangibles are included in General Plant such as land rights and computer software.

General Plant expenditures for 2023 to 2024 are expected to be higher than the historical average of 2014 to 2022. In 2024, OHL is planning a roof replacement, a new customer portal, a new GIS system and a financial software upgrade.

Table 2-35 – General Plant Additions

Projects	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023 Bridge Year	2024 Test Year
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
General Plant											
Building	15,781	54,950	975	6,638	69,750	35,528	25,149	5,633	38,033	75,801	296,000
Computer Software	128,647	17,669	16,184	53,881	22,371	49,155	21,059	22,675	25,735	15,525	197,380
Land Rights	-	10,819	2,848	1,250	-	-	4,089	-	-	-	-
Office Equipment	-	6,551	1,182	2,131	29,417	19,450	-	-	6,335	5,000	30,000
Computer Hardware	28,386	25,403	30,145	5,051	13,899	30,296	44,717	29,188	41,159	11,695	58,000
Vehicles	327,917	51,619	93,016	35,650	293,225	32,823	181,741	-	-	-	93,815
Stores equipment	-	-	-	1,899	-	-	-	-	-	2,000	2,000
Tools, Shop & Garage Equipment	3,704	9,121	9,818	600	15,957	1,014	-	700	-	2,000	6,500
Measurement & Testing Equipment	365	11,212	1,748	14,934	1,911	2,997	3,769	171	19,019	2,778	24,222
Communications Equipment	-	1,651	-	-	-	-	-	801	2,243	7,584	1,000
Miscellaneous Equipment	2,350	2,479	11,600	5,516	4,166	-	-	7,024	2,399	2,000	2,000
General Plant Gross Expenditures	**507,152**	**191,473**	**167,516**	**127,549**	**450,696**	**171,264**	**280,525**	**66,192**	**134,922**	**124,383**	**710,917**

2.2.4 ASSET VARIANCE ANALYSIS BY OEB CATEGORY

Table 2-36 – Capital Expenditures 2014 OEB-Approved vs 2014 Actuals

Category	2014 Board Approved	2014 Actual	Variance	Variance %
System Access	$411,106	$940,972	$529,866	129%
System Renewal	525,050	305,569	(219,481)	(42%)
System Service	595,456	413,471	(181,985)	(31%)
General Plant	493,500	507,152	13,652	3%
Total Gross Expenditures	**$2,025,112**	**$2,167,163**	**$142,052**	7%
Capital Contributions	($298,474)	($538,014)	($239,540)	80%
Net Capital Expenditures	$1,726,638	$1,629,149	($97,488)	(6%)

System Access

Actual System Access expenditures were 129% higher than the 2014 DSP Plan for 2014. The increase was mainly due to the energization of 3 subdivisions and more servicing of general service and residential customers, which are all customer-driven requests.

System Renewal

Actual System Renewal expenditures were 42% lower than the 2014 DSP Plan for 2014. The decrease was mainly due to the deferral of the West Broadway project to replace poles and transformers. The scope of the work changed and the work was completed in 2022.

System Service

Actual System Service expenditures were 31% lower than the 2014 DSP Plan for 2014. The decrease was mainly due to the deferral of two 27.6 kV conversion projects because of more resources being spent on System Access projects.

General Plant

Actual General Plant expenditures were 3% higher than the 2014 DSP Plan for 2014. The amount of this variance is below materiality.

Table 2-37 – Capital Expenditures 2015 Actuals vs 2014 Actuals

Category	2015 Actuals	2014 Actuals	Variance	Variance %
System Access	$263,560	$940,972	($677,412)	(72%)
System Renewal	236,946	305,569	(68,622)	(22%)
System Service	601,128	413,471	187,657	45%
General Plant	191,473	507,152	(315,679)	(62%)
Total Gross Expenditures	**$1,293,107**	**$2,167,163**	**($874,056)**	(40%)
Contributed Capital	($200,284)	($538,014)	$337,730	(63%)
Net Capital Expenditures	$1,092,823	$1,629,149	($536,327)	(33%)

System Access

There was a 72% decrease in System Access expenditures from 2014 to 2015 actuals. The decrease was driven by the energization of 3 subdivisions in 2014, as compared to 1 subdivision in 2015.

System Renewal

There was a 22% decrease in System Renewal expenditures from 2014 to 2015 actuals. The main driver is due to a transformer and transformer foundation replacements in Parkview Heights in 2014. The legacy foundations were undersized and unable to properly support new transformers when the old transformer failed. In 2015, there was not a system renewal project of this size, leading to a year over year decrease.

System Service

There was a 45% increase in System Service expenditures from 2014 to 2015 actuals. The increase was due to re-prioritization at Water & William St in 2015 to upgrade the infrastructure for asset optimization, equipment standardization and reliability.

General Plant

There was a 62% decrease in General Plant expenditures from 2014 to 2015 actuals. The decrease was due to the 2014 purchase of Truck #33, a 2015 Altec RBD (digger truck) which replaced Truck #11.

Table 2-38 – Capital Expenditures 2016 Actuals vs 2015 Actuals

Category	2016 Actuals	2015 Actuals	Variance	Variance %
System Access	$1,088,050	$263,560	$824,490	313%
System Renewal	251,590	236,946	14,644	6%
System Service	433,835	601,128	(167,293)	(28%)
General Plant	167,516	191,473	(23,956)	(13%)
Total Gross Expenditures	**$1,940,991**	**$1,293,107**	**$647,884**	50%
Contributed Capital	($395,789)	($200,284)	($195,505)	98%
Net Capital Expenditures	$1,545,201	$1,092,823	$452,378	41%

System Access

There was a 313% increase in System Access expenditures from 2015 to 2016 actuals. The increase was driven by the energization of 1 subdivision in 2015, as compared to 2 subdivisions in 2016, which included Riddell Row Servicing, which was a commercial subdivision.

System Renewal

There was a 6% increase in System Renewal expenditures from 2015 to 2016 actuals. The amount of this variance is below materiality.

System Service

There was a 28% decrease in System Service expenditures from 2015 to 2016 actuals. The decrease was due to a re-prioritization of the Water & William St 27.6kV conversion as well as Centre & Church St 27.6kV conversion jobs to 2015 to upgrade the infrastructure for asset optimization, equipment standardization and reliability.

General Plant

There was a 13% decrease in General Plant expenditures from 2015 to 2016 actuals. The amount of this variance is below materiality.

Table 2-39 – Capital Expenditures 2017 Actuals vs 2016 Actuals

Category	2017 Actuals	2016 Actuals	Variance	Variance %
System Access	$1,655,660	$1,088,050	$567,610	52%
System Renewal	248,552	251,590	(3,039)	(1%)
System Service	519,849	433,835	86,015	20%
General Plant	127,549	167,516	(39,967)	(24%)
Total Gross Expenditures	**$2,551,610**	**$1,940,991**	**$610,619**	31%
Contributed Capital	($633,962)	($395,789)	($238,172)	60%
Net Capital Expenditures	$1,917,648	$1,545,201	$372,447	24%

System Access

There was a 52% increase in System Access expenditures from 2016 to 2017 actuals. The increase was driven by the energization of 2 subdivisions in 2016, as compared to 6 subdivisions in 2017.

System Renewal

There was a 1% decrease in System Renewal expenditures from 2016 to 2017 actuals. The amount of this variance is below materiality.

System Service

There was a 20% increase in System Service expenditures from 2016 to 2017 actuals. The increase was due to 27.6 kV Conversion MS 4-E Feeder (East of Faulkner) Phase 1 which continued into 2018.

General Plant

There was a 24% decrease in General Plant expenditures from 2016 to 2017 actuals. The amount of this variance is below materiality.

Table 2-40 – Capital Expenditures 2018 Actuals vs 2017 Actuals

Category	2018 Actuals MIFRS	2017 Actuals MIFRS	Variance ($)	Variance %
System Access (Gross)	509,508	1,655,660	1,146,152	225%
System Renewal (Gross)	201,614	248,552	46,937	23%
System Service (Gross)	625,952	519,849	(106,103)	-17%
General Plant (Gross)	443,852	127,549	(316,303)	-71%
Gross Capital Expenses	**1,780,926**	**2,551,610**	**770,684**	**43%**
Contributed Capital	(198,868)	(633,962)	(435,094)	219%
Net Capital Expenses	**1,582,058**	**1,917,648**	**335,590**	**21%**

<u>System Access</u>

There was a 69% decrease in System Access expenditures from 2017 to 2018 actuals. The decrease was driven by the energization of 6 subdivisions in 2017, as compared to 4 subdivisions in 2018.

<u>System Renewal</u>

There was a 22% decrease in System Renewal expenditures from 2017 to 2018 actuals. The decrease was driven by the amount of transformers moved out of inventory in 2018 for use in job B105.

<u>System Service</u>

There was a 20% increase in System Service expenditures from 2017 to 2018 actuals. The increase was mainly due to a large 27.6 kV Conversion for our MS4-E Feeder Phase 2 and a Riddell Road feeder tie project in 2018.

<u>General Plant</u>

There was a 253% increase in General Plant expenditures from 2017 to 2018 actuals. The increase was due to the purchase of Truck 38, a 2018 Freightliner single bucket truck (Posi-Plus) in 2018 which replaced Truck 19.

Table 2-41 – Capital Expenditures 2019 Actuals vs 2018 Actuals

Category	2019 Actuals MIFRS	2018 Actuals MIFRS	Variance ($)	Variance %
System Access (Gross)	302,685	509,508	206,823	68%
System Renewal (Gross)	217,629	201,614	(16,014)	-7%
System Service (Gross)	676,650	625,952	(50,698)	-7%
General Plant (Gross)	171,264	450,696	279,432	163%
Gross Capital Expenses	**1,368,228**	**1,787,770**	**419,542**	**31%**
Contributed Capital	(114,921)	(205,712)	(90,792)	79%
Net Capital Expenses	**1,253,307**	**1,582,058**	**328,751**	**26%**

System Access

There was a 41% decrease in System Access expenditures from 2018 to 2019 actuals. The decrease was mostly driven by the energization of 4 subdivisions in 2018, as compared to 3 subdivisions in 2019. There was also decreased activity due to the servicing of commercial and industrial customers.

System Renewal

There was an 8% increase in System Renewal expenditures from 2018 to 2019 actuals. The amount of this variance is below materiality.

System Service

There was an 8% increase in System Service expenditures from 2018 to 2019 actuals. The increase was due to a large 27.6 kV conversion project in 2019 for Rear Broadway and the completion of the Riddell Road feeder tie.

General Plant

There was a 62% decrease in General Plant expenditures from 2018 to 2019 actuals. The decrease was due to the purchase of Truck #38, a 2018 Freightliner single bucket truck (Posi-Plus) in 2018 which replaced Truck #19.

Table 2-42 – Capital Expenditures 2020 Actuals vs 2019 Actuals

Category	2020 Actuals	2019 Actuals	Variance	Variance %
System Access	$372,926	$302,685	$70,241	23%
System Renewal	394,476	217,629	176,847	81%
System Service	877,012	676,650	200,362	30%
General Plant	280,525	171,264	109,261	64%
Total Gross Expenditures	**$1,924,938**	**$1,368,228**	**$556,710**	41%
Contributed Capital	($239,979)	($114,921)	($125,058)	109%
Net Capital Expenditures	$1,684,959	$1,253,307	$431,652	34%

System Access

There was a 23% increase in System Access expenditures from 2019 to 2020 actuals. The increase was driven by the energization of the Cachet Grand Valley subdivision and increased activity due to the servicing of commercial and industrial customers.

System Renewal

There was an 81% increase in System Renewal expenditures from 2019 to 2020 actuals. The increase was driven by increased transformer purchases in order to get ready for job B113 in 2021 and increased transformer replacements. These transformers made out of mild steel were corroding faster than previously expected. OHL is now buying stainless steel transformers and piloting an in-field refurbishment and painting of transformers to extend the life of the assets.

System Service

There was a 30% increase in System Service expenditures from 2019 to 2020 actuals. The increase was due to Third St/Second St 27.6KV Conversion which was brought forward in order to upgrade the Express M26 feeder.

General Plant

There was a 64% increase in General Plant expenditures from 2019 to 2020 actuals. The increase was due to the purchase of a single bucket truck (Altec) Truck #40 2020 Ford F550 in 2020.

Table 2-43 – Capital Expenditures 2021 Actuals vs 2020 Actuals

Category	2021 Actuals	2020 Actuals	Variance	Variance %
System Access	$736,527	$372,926	$363,601	97%
System Renewal	530,019	394,476	135,544	34%
System Service	925,386	877,012	48,374	6%
General Plant	66,192	280,525	(214,332)	(76%)
Total Gross Expenditures	**$2,258,125**	**$1,924,938**	**$333,187**	17%
Contributed Capital	($349,139)	($239,979)	($109,160)	45%
Net Capital Expenditures	$1,908,986	$1,684,959	$224,027	13%

<ins>System Access</ins>

There was a 97% increase in System Access expenditures from 2020 to 2021 actuals. The increase was due to a large subdivision energization in Grand Valley, Mayberry Hill Phase 3A. The Town of Orangeville did a road widening and re-alignment along Centennial Road. There was also increased activity due to servicing of commercial and industrial customers post-pandemic, the main project being a Tesla EV charging station built at the Fairgrounds Shopping Centre.

<ins>System Renewal</ins>

There was a 34% increase in System Renewal expenditures from 2020 to 2021 actuals. The driver for the increase was driven by a pole line renewal on Main St in Grand Valley.

<ins>System Service</ins>

There was a 6% increase in System Service expenditures from 2020 to 2021 actuals. The increase was due to MS2-West Feeder conversion job. This voltage conversion of an industrial street in Orangeville consisted of more 3-phase transformer customers than most of OHL's historical conversion projects. It was more expensive due to a combination of overhead and underground plant. Most of the conversion projects done in the past involved 1-phase transformers and overhead plant only.

<ins>General Plant</ins>

There was a 76% decrease in General Plant expenditures from 2020 to 2021 actuals. The decrease was due to last year's purchase of a single bucket truck (Altec) Truck #40 2020 Ford F550.

Table 2-44 – Capital Expenditures 2022 Actuals vs 2021 Actuals

Category	2022 Actuals	2021 Actuals	Variance	Variance %
System Access	$96,413	$736,527	($640,114)	(87%)
System Renewal	554,050	$530,019	24,031	5%
System Service	2,197,624	$925,386	1,272,238	137%
General Plant	134,922	$66,192	68,730	104%
Total Gross Expenditures	**$2,983,010**	**$2,258,125**	**$724,886**	32%
Contributed Capital	($62,566)	($349,139)	$286,573	(82%)
Net Capital Expenditures	$2,920,445	$1,908,986	$1,011,459	53%

System Access

There was an 87% decrease in System Access expenditures from 2021 to 2022 actuals. The decrease was driven by no energization of subdivisions in 2022, and decreased activity due to servicing of commercial and industrial customers.

System Renewal

There was a 5% increase in System Renewal expenditures from 2021 to 2022 actuals. The increase was driven by the increased cost of materials.

System Service

There was a 137% increase in System Service expenditures from 2022 to 2021 actuals. The increase was due to projects being brought forward from future years. MS-2 South Feeder conversion expanded to two new areas: Edelwild/Avonmore/Johanna ($492K) and Edelwild/Rustic/Cedar/Lawrence ($596K). In this area were large fiber projects where it was beneficial for OHL to bury duct jointly with the fiber company to minimize impacts to customers in those areas. This reduces the risk of not having an acceptable location to install electrical duct banks underground and realize cost efficiencies from open trench as opposed to more costly directional drilling to bury ducts.

General Plant

There was a 104% increase in General Plant expenditures from 2021 to 2022 actuals. The increase was due to a bathroom renovation and a conversion to LED lights.

Table 2-45 – Capital Expenditures 2023 Bridge vs 2022 Actuals

Category	2023 Bridge	2022 Actuals	Variance	Variance %
System Access	$820,036	$96,413	$723,622	751%
System Renewal	583,185	$554,050	29,134	5%
System Service	976,919	$2,197,624	(1,220,705)	(56%)
General Plant	124,383	$134,922	(10,539)	(8%)
Total Gross Expenditures	**$2,504,522**	**$2,983,010**	**($478,488)**	(16%)
Contributed Capital	($451,067)	($62,566)	($388,501)	621%
Net Capital Expenditures	$2,053,455	$2,920,445	($866,989)	(30%)

System Access

There is a 751% increase in System Access expenditures from 2022 to 2023. The increase was driven by 3 subdivisions relative to no subdivision in 2022. 62A-68 First Street, Mayberry Hill Phase 3A Block 43 and 670-690 Broadway have been energized in 2023.

System Renewal

There is a 5% increase in System Renewal expenditures from 2022 to 2023. The increase was driven by a primary sleeve replacement program. This program is designed to remove the automatic tension sleeves from the primary distribution system to be replaced with compression sleeves. The need for this program was identified after the December 2022 blizzard which triggered OHL to file a major event report with the OEB.

System Service

There is a 56% decrease in System Service expenditures from 2022 to 2023 actuals. The decrease is due to the two large voltage conversions in 2022 as a result of the installation of cable duct along with fiber.

General Plant

There is an 8% decrease in General Plant expenditures from 2022 to 2023, which is not material.

Table 2-46 – Capital Expenditures 2024 Test vs 2023 Bridge

Category	2024 Test	2023 Bridge	Variance	Variance %
System Access	$1,359,889	$820,036	$539,854	66%
System Renewal	787,454	$583,185	204,269	35%
System Service	818,940	$976,919	(157,979)	(16%)
General Plant	710,917	$124,383	586,534	472%
Total Gross Expenditures	**$3,677,200**	**$2,504,522**	**$1,172,678**	47%
Contributed Capital	($718,936)	($451,067)	($267,869)	59%
Net Capital Expenditures	$2,958,264	$2,053,455	$904,809	44%

System Access

There is a 66% increase in System Access expenditures from 2023 to 2024 actuals. The increase is driven by 2 subdivisions. Edgewood Valley Developments Phase 2B is a detached home development which is much larger than OHL's typical subdivision connection projects. Another Grand Valley detached home development is expected to be energized and has been confirmed to OHL by the developers.

System Renewal

There is a 35% increase in System Renewal expenditures from 2023 to 2024. The increase is driven by a sleeve replacement program as described in the 2023 vs 2022 variance analysis.

System Service

There is a 16% decrease in System Service expenditures from 2023 to 2024. The decrease is due to there being smaller voltage conversion projects than in the prior year and more resources spent on System Access and System Renewal projects.

General Plant

There is a 472% increase in General Plant expenditures from 2023 to 2024. The increase is due to a much needed roof replacement, a new industry standard of GIS, a financial software upgrade and an enhanced customer portal. OHL's building was built in 1990 and the roof is beyond its life expectancy. OHL was informed by a third party that it is in serious need of replacement. OHL's existing customer portal is no longer being supported and is increasing cybersecurity concerns. It also provides customers with poor customer experience when they attempt to manage their accounts online.

2.2.5 COSTS FOR ANY ICM OR ACM FROM PREVIOUS IRM APPLICATIONS

OHL has not applied or been approved for any ICM or ACM costs in IRM applications since it re-based in its 2014 CoS.

2.3 DEPRECIATION, AMORTIZATION AND DEPLETION

2.3.1 KINECTRICS REPORT

OHL has adopted depreciation rates based on the Kinectrics Asset Depreciation Study (“KADS”). The rates used are presented in the table below.

OHL uses the half year rule for recording depreciation on both additions and disposals. OHL uses the MIFRS standard and separates significant components as required. Details can be found in Section 2.3.5 Depreciation Policy or Appendix 2-B Depreciation Policy.

All useful lives of assets are within the ranges contained in the Kinectrics Report.

Table 2-47 – Service Life Comparison to Kinectrics Report

		Asset Details			Useful Life			USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
Parent*	#	Category| Component | Type			MIN UL	TUL	MAX UL			Years	Rate	Years	Rate	Below Min TUL	Above Max TUL
OH	1	Fully Dressed Wood Poles	Overall		35	45	75	1830	Poles, Towers & Fixtures	45	2%	45	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	2	Fully Dressed Concrete Poles	Overall		50	60	80	1830	Poles, Towers & Fixtures	60	2%	60	2%	No	No
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	3	Fully Dressed Steel Poles	Overall		60	60	80								
			Cross Arm	Wood	20	40	55								
				Steel	30	70	95								
	4	OH Line Switch			30	45	55	1835	Overhead Conductors & Devices	45	2%	45	2%	No	No
	5	OH Line Switch Motor			15	25	25								
	6	OH Line Switch RTU			15	20	20								
	7	OH Integral Switches			35	45	60								
	8	OH Conductors			50	60	75	1835	Overhead Conductors & Devices	60	2%	60	2%	No	No
	9	OH Transformers & Voltage Regulators			30	40	60								
	10	OH Shunt Capacitor Banks			25	30	40								
	11	Reclosers			25	40	55								
TS & MS	12	Power Transformers	Overall		30	45	60	1850	Line Transformers	40	3%	40	3%	No	No
			Bushing		10	20	30								
			Tap Changer		20	30	60								
	13	Station Service Transformer			30	45	55								
	14	Station Grounding Transformer			30	40	40								
	15	Station DC System	Overall		10	20	30								
			Battery Bank		10	15	15								
			Charger		20	20	30								
	16	Station Metal Clad Switchgear	Overall		30	40	60	1820	Distribution Station Equipment - Below 5	40	3%	40	3%	No	No
			Removable Breaker		25	40	60								
	17	Station Independent Breakers			35	45	65								
	18	Station Switch			30	50	60	1820	Distribution Station Equipment - Below 5	50	2%	50	2%	No	No
	19	Electromechanical Relays			25	35	50								
	20	Solid State Relays			10	30	45								
	21	Digital & Numeric Relays			15	20	20								
	22	Rigid Busbars			30	55	60								
	23	Steel Structure			35	50	90	1820	Distribution Station Equipment - Below 5	50	2%	50	2%	No	No
UG	24	Primary Paper Insulated Lead Covered (PILC) Cables			60	65	75								
	25	Primary Ethylene-Propylene Rubber (EPR) Cables			20	25	25								
	26	Primary Non-Tree Retardant (Non-TR) Cross Linked Polyethylene (XLPE) Cables Direct Buried			20	25	30								
	27	Primary Non-TR XLPE Cables in Duct			20	25	30								
	28	Primary TR XLPE Cables Direct Buried			25	30	35	1845	Underground Conductors & Devices	30	3%	30	3%	No	No
	29	Primary TR XLPE Cables in Duct			35	40	55	1845	Underground Conductors & Devices	40	3%	40	3%	No	No
	30	Secondary PILC Cables			70	75	80								
	31	Secondary Cables Direct Buried			25	35	40	1855	Services	35	3%	35	3%	No	No
	32	Secondary Cables in Duct			35	40	60	1855	Services	40	3%	40	3%	No	No
	33	Network Tranformers	Overall		20	35	50								
			Protector		20	35	40								
	34	Pad-Mounted Transformers			25	40	45	1850	U/G Line Transformers	40	3%	40	3%	No	No
	35	Submersible/Vault Transformers			25	35	45								
	36	UG Foundation			35	55	70	1845	Underground Conductors & Devices	55	2%	55	2%	No	No
	37	UG Vaults	Overall		40	55	80								
			Roof		20	30	45								
	38	UG Vault Switches			20	35	50								
	39	Pad-Mounted Switchgear			20	30	45	1845	Underground Conductors & Devices	30	3%	30	3%	No	No
	40	Ducts			30	50	85	1840	Underground Conduit	50	2%	50	2%	No	No
	41	Concrete Encased Duct Banks			35	55	80	1840	Underground Conduit	55	2%	55	2%	No	No
	42	Cable Chambers			50	60	80								
S	43	Remote SCADA			15	20	30								

Table F-2 from Kinetrics Report[1]

	Asset Details		Useful Life Range		USoA Account Number	USoA Account Description	Current		Proposed		Outside Range of Min, Max TUL?	
#	Category| Component | Type						Years	Rate	Years	Rate	Below Min Range	Above Max Range
1	Office Equipment		5	15	1915	Office Furniture & Equipment	10	10%	10	10%	No	No
2	Vehicles	Trucks & Buckets	5	15	1935	ansportation Equipment - Trucks over 3 t	12	8%	12	8%	No	No
		Trailers	5	20								
		Vans	5	10	1935	nsportation Equipment - Trucks under 3 t	8	13%	8	13%	No	No
3	Administrative Buildings		50	75	1908	Building & Fixtures - General Plant	50	2%	50	2%	No	No
4	Leasehold Improvements		Lease dependent									
5	Station Buildings	Station Buildings	50	75								
		Parking	25	30								
		Fence	25	60								
		Roof	20	30								
6	Computer Equipment	Hardware	3	5	1920	Computer Equipment - Hardware	5	20%	5	20%	No	No
		Software	2	5	1610	Computer Software	5	20%	5	20%	No	No
7	Equipment	Power Operated	5	10								
		Stores	5	10	1935	Stores Equipment	10	10%	10	10%	No	No
		Tools, Shop, Garage Equipment	5	10	1940	Tools, Shop & Garage Equipment	10	10%	10	10%	No	No
		Measurement & Testing Equipment	5	10	1945	Measurement & Testing Equipment	10	10%	10	10%	No	No
8	Communication	Towers	60	70	1955	Communication Equipment	60	2%	60	2%	No	No
		Wireless	2	10	1955	Communication Equipment	10	10%	10	10%	No	No
9	Residential Energy Meters		25	35								
10	Industrial/Commercial Energy Meters		25	35	1860	Commercial Meter Distribution	25	4%	25	4%	No	No
11	Wholesale Energy Meters		15	30	1820	Wholesale Meters	15	7%	15	7%	No	No
12	Current & Potential Transformer (CT & PT)		35	50	1860	CT's & PT's	50	2%	50	2%	No	No
13	Smart Meters		5	15	1860	Residential Meter Distribution	15	7%	15	7%	No	No
14	Repeaters - Smart Metering		10	15								
15	Data Collectors - Smart Metering		15	20								

2.3.2 DEPRECIATION AND AMORTIZATION BY ASSET GROUP

As conveyed in 2.3.1 Kinectrics Report section, OHL uses the half year rule for recording depreciation on both additions and disposals. The formula in column E *Net Amount of Assets to be Depreciated* has been amended by OHL to reflect this.

Table 2-48 – 2014 MIFRS Depreciation and Amortization Continuity

Year 2014

		Book Values				Service Lives		Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 202,153		$ 128,876	$ -	$ 266,591	2.84	35.21%	**$ 93,870**	$ 103,180	**$ 9,310**
1612	Land Rights (Formally known as Account 1906)	$ 39,972		$ 38,902	$ -	$ 59,423	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 122,655		$ -	$ -	$ 122,655	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 352,630		$ 5,108	$ -	$ 355,184	8.76	11.42%	**$ 40,546**	$ 39,329	**-$ 1,217**
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 1,423,630		$ 109,302	$ 6,730	$ 1,481,646	34.18	2.93%	**$ 43,348**	$ 52,432	**$ 9,084**
1835	Overhead Conductors & Devices	$ 1,598,812		$ 94,691	$ 3,119	$ 1,647,717	47.48	2.11%	**$ 34,703**	$ 36,105	**$ 1,401**
1840	Underground Conduit	$ 2,194,259		$ 474,995	$ -	$ 2,431,756	41.94	2.38%	**$ 57,982**	$ 59,231	**$ 1,249**
1845	Underground Conductors & Devices	$ 2,550,182		$ 311,597	$ -	$ 2,705,981	25.66	3.90%	**$ 105,455**	$ 139,078	**$ 33,623**
1850	Line Transformers	$ 2,673,599		$ 380,201	$ 19,938	$ 2,873,668	31.07	3.22%	**$ 92,490**	$ 103,788	**$ 11,298**
1855	Services (Overhead & Underground)	$ 651,180		$ 193,244	$ -	$ 747,802	26.80	3.73%	**$ 27,903**	$ 31,817	**$ 3,914**
1860	Meters	$ 1,467,670		$ 51,973	$ 25,472	$ 1,506,392	12.09	8.27%	**$ 124,598**	$ 120,456	**-$ 4,142**
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ 144,400		$ -	$ -	$ 144,400	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,776,831		$ 15,781	$ 1,333	$ 1,785,388	24.05	4.16%	**$ 74,237**	$ 76,449	**$ 2,213**
1910	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 89,832		$ -	$ -	$ 89,832	5.00	20.00%	**$ 17,966**	$ 14,940	**-$ 3,026**
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 44,238		$ 28,157	$ 1,578	$ 59,105	7.89	12.67%	**$ 7,491**	$ 22,358	**$ 14,866**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 221,833		$ 327,917	$ 8,830	$ 390,207	8.75	11.43%	**$ 44,595**	$ 53,102	**$ 8,507**
1935	Stores Equipment	$ 6,212		$ -	$ -	$ 6,212	10.00	10.00%	**$ 621**	$ 1,215	**$ 594**
1940	Tools, Shop & Garage Equipment	$ 21,264		$ 3,704	$ 102	$ 23,167	10.00	10.00%	**$ 2,317**	$ 3,837	**$ 1,521**
1945	Measurement & Testing Equipment	$ 15,030		$ 365	$ -	$ 15,212	10.00	10.00%	**$ 1,521**	$ 1,812	**$ 291**
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 125		$ -	$ -	$ 125	10.00	10.00%	**$ 12**	$ 125	**$ 112**
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 98,674		$ 2,350	$ -	$ 99,849	10.00	10.00%	**$ 9,985**	$ 15,891	**$ 5,906**
1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	$ -		-$ 538,014	$ -	-$ 269,007	38.83	2.58%	**-$ 6,928**	-$ 6,962	**-$ 34**
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
	Total	**$ 15,695,180**	**$ -**	**$ 1,629,149**	**$ 67,101**	**$ 16,543,305**			**$ 772,714**	**$ 868,183**	**$ 95,469**
											11.0%

Table 2-49 – 2015 MIFRS Depreciation and Amortization Continuity

Year 2015

		Book Values				Service Lives		Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 331,029	$ 18,868	$ 17,669	$ 56,259	$ 349,125	5.00	20.00%	**$ 69,825**	$ 84,971	**$ 15,146**
1612	Land Rights (Formally known as Account 1906)	$ 78,874	$ -	$ 23,933	$ -	$ 90,841	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 122,655	$ -	$ -	$ 100,000	$ 172,655	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 357,738	$ -	$ 38,633	$ -	$ 377,055	8.90	11.24%	**$ 42,366**	$ 40,497	**-$ 1,868**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 1,526,202	$ -	$ 110,012	$ 2,923	$ 1,582,669	33.97	2.94%	**$ 46,590**	$ 52,507	**$ 5,916**
1835	Overhead Conductors & Devices	$ 1,690,384	$ -	$ 73,798	$ 15,900	$ 1,735,233	48.58	2.06%	**$ 35,719**	$ 37,090	**$ 1,371**
1840	Underground Conduit	$ 2,669,254	$ -	$ 282,139	$ -	$ 2,810,323	41.15	2.43%	**$ 68,295**	$ 66,704	**-$ 1,591**
1845	Underground Conductors & Devices	$ 2,861,779	$ -	$ 132,212	$ -	$ 2,927,885	25.11	3.98%	**$ 116,602**	$ 145,234	**$ 28,631**
1850	Line Transformers	$ 3,033,862	$ 80	$ 344,561	$ 10,726	$ 3,211,425	30.97	3.23%	**$ 103,695**	$ 108,446	**$ 4,752**
1855	Services (Overhead & Underground)	$ 844,424	$ -	$ 84,866	$ -	$ 886,857	26.70	3.75%	**$ 33,216**	$ 33,233	**$ 18**
1860	Meters	$ 1,494,171	$ 475	$ 22,300	$ 12,260	$ 1,510,975	12.09	8.27%	**$ 124,977**	$ 120,634	**-$ 4,343**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ 144,400	$ -	$ -	$ -	$ 144,400	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,791,280	$ -	$ 54,950	$ -	$ 1,818,755	24.95	4.01%	**$ 72,896**	$ 77,883	**$ 4,987**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 89,832	$ -	$ 6,551	$ 988	$ 93,601	15.00	6.67%	**$ 6,240**	$ 14,237	**$ 7,997**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 70,817	$ 419	$ 25,403	$ 11,413	$ 88,805	5.00	20.00%	**$ 17,761**	$ 20,259	**$ 2,498**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 540,921	$ -	$ 51,619	$ -	$ 566,730	8.75	11.43%	**$ 64,769**	$ 69,232	**$ 4,463**
1935	Stores Equipment	$ 6,212	$ -	$ -	$ -	$ 6,212	10.00	10.00%	**$ 621**	$ 1,150	**$ 529**
1940	Tools, Shop & Garage Equipment	$ 24,867	$ -	$ 9,121	$ -	$ 29,427	10.00	10.00%	**$ 2,943**	$ 4,320	**$ 1,377**
1945	Measurement & Testing Equipment	$ 15,395	$ -	$ 11,212	$ -	$ 21,001	10.00	10.00%	**$ 2,100**	$ 2,532	**$ 432**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 125	$ 0	$ 1,651	$ -	$ 950	10.00	10.00%	**$ 95**	$ 124	**$ 29**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 101,024	$ -	$ 2,479	$ -	$ 102,263	10.00	10.00%	**$ 10,226**	$ 16,876	**$ 6,650**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 538,014	$ -	-$ 200,284	-$ 5,589	-$ 640,950	38.83	2.58%	**-$ 16,507**	-$ 15,819	**$ 688**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
	Total	**$ 17,257,229**	**$ 19,842**	**$ 1,092,823**	**$ 204,879**	**$ 17,886,237**			**$ 802,430**	**$ 880,110**	**$ 77,680**
											8.8%

Table 2-50 – 2016 MIFRS Depreciation and Amortization Continuity

Year 2016

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 292,440	$ 6,160	$ 16,184	$ -	$ 294,372	5.00	20.00%	$ 58,874	$ 64,625	$ 5,750
1612	Land Rights (Formally known as Account 1906)	$ 102,808	$ -	$ 9,060	$ -	$ 107,338	-	0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 396,371	$ 21,039	$ 59,927	$ -	$ 405,295	13.39	7.47%	$ 30,269	$ 32,130	$ 1,862
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,633,291	$ 13,375	$ 101,069	$ 5,119	$ 1,673,010	33.69	2.97%	$ 49,659	$ 49,045	-$ 614
1835	Overhead Conductors & Devices	$ 1,748,282	$ 1,361	$ 77,897	$ 8,090	$ 1,789,915	46.67	2.14%	$ 38,353	$ 37,246	-$ 1,107
1840	Underground Conduit	$ 2,951,393	$ -	$ 397,357	$ -	$ 3,150,071	42.56	2.35%	$ 74,015	$ 73,217	-$ 798
1845	Underground Conductors & Devices	$ 2,993,990	$ 57,410	$ 620,750	$ -	$ 3,246,955	25.83	3.87%	$ 125,705	$ 128,590	$ 2,885
1850	Line Transformers	$ 3,367,697	$ 4,779	$ 280,720	$ 15,150	$ 3,510,853	30.50	3.28%	$ 115,110	$ 113,829	-$ 1,281
1855	Services (Overhead & Underground)	$ 929,290	$ -	$ 144,507	$ -	$ 1,001,543	27.34	3.66%	$ 36,633	$ 35,474	-$ 1,159
1860	Meters	$ 1,504,211	$ 539	$ 85,035	$ 2,921	$ 1,547,649	11.00	9.09%	$ 140,695	$ 122,786	-$ 17,910
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 144,400	$ -	$ -	$ -	$ 144,400	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,846,230	$ -	$ 975	$ -	$ 1,846,717	22.21	4.50%	$ 83,148	$ 79,261	-$ 3,887
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 95,394	$ 258	$ 1,182	$ -	$ 95,728	10.00	10.00%	$ 9,573	$ 14,312	$ 4,739
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 84,807	$ 10,257	$ 30,145	$ 6,067	$ 92,656	5.00	20.00%	$ 18,531	$ 18,758	$ 227
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 592,540	$ -	$ 93,016	$ 12,988	$ 645,542	8.82	11.34%	$ 73,191	$ 76,474	$ 3,284
1935	Stores Equipment	$ 6,212	$ -	$ -	$ -	$ 6,212	10.00	10.00%	$ 621	$ 1,153	$ 532
1940	Tools, Shop & Garage Equipment	$ 33,988	$ 62	$ 9,818	$ 42	$ 38,856	10.00	10.00%	$ 3,886	$ 5,166	$ 1,280
1945	Measurement & Testing Equipment	$ 26,607	$ -	$ 1,748	$ -	$ 27,481	10.00	10.00%	$ 2,748	$ 3,065	$ 316
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,775	$ 125	$ -	$ -	$ 1,651	10.00	10.00%	$ 165	$ 165	-$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 103,503	$ 801	$ 11,600	$ -	$ 108,502	10.00	10.00%	$ 10,850	$ 17,360	$ 6,510
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 732,709	$ -	-$ 395,789	$ -	-$ 930,604	46.61	2.15%	-$ 19,966	-$ 23,431	-$ 3,465
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 18,145,173**	**$ 116,165**	**$ 1,545,201**		**$ 18,826,797**			**$ 852,059**	**$ 849,223**	**-$ 2,836**
											-0.3%

Table 2-51 – 2017 MIFRS Depreciation and Amortization Continuity

Year 2017

		Book Values				Service Lives		Expense			
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Disposals**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets, Column J**	**Variance [4]**
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 308,624	$ 51,489	$ 53,881	$ 21,652	$ 294,902	5.00	20.00%	$ 58,980	$ 52,426	-$ 6,554
1612	Land Rights (Formally known as Account 1906)	$ 111,868	$ -	$ 1,250	$ -	$ 112,493		0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 456,298	$ 24,288	$ 27,393	$ -	$ 445,707	12.69	7.88%	$ 35,123	$ 32,849	-$ 2,274
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,729,241	$ 13,375	$ 137,524	$ 2,646	$ 1,785,951	33.59	2.98%	$ 53,169	$ 51,392	-$ 1,777
1835	Overhead Conductors & Devices	$ 1,818,089	$ 1,361	$ 81,349	$ -	$ 1,857,403	46.26	2.16%	$ 40,151	$ 38,288	-$ 1,864
1840	Underground Conduit	$ 3,348,750	$ -	$ 817,759	$ -	$ 3,757,629	43.28	2.31%	$ 86,821	$ 85,029	-$ 1,792
1845	Underground Conductors & Devices	$ 3,614,740	$ 57,410	$ 417,170	$ 9,048	$ 3,770,439	26.28	3.81%	$ 143,472	$ 142,008	-$ 1,463
1850	Line Transformers	$ 3,633,268	$ 4,637	$ 545,063	$ 13,823	$ 3,908,074	30.81	3.25%	$ 126,844	$ 124,375	-$ 2,469
1855	Services (Overhead & Underground)	$ 1,073,797	$ -	$ 321,690	$ -	$ 1,234,642	29.21	3.42%	$ 42,268	$ 40,154	-$ 2,114
1860	Meters	$ 1,586,325	$ 539	$ 76,111	$ 18,583	$ 1,633,133	10.33	9.68%	$ 158,096	$ 125,895	-$ 32,201
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 144,400	$ -	$ -	$ 33,559	$ 161,180	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,847,205	$ -	$ 6,638	$ -	$ 1,850,524	26.44	3.78%	$ 69,990	$ 79,203	$ 9,213
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 96,577	$ 258	$ 2,131	$ -	$ 97,384	10.00	10.00%	$ 9,738	$ 12,303	$ 2,565
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 108,885	$ 8,710	$ 5,051	$ 16,408	$ 110,904	5.00	20.00%	$ 22,181	$ 19,123	-$ 3,058
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 672,567	$ -	$ 35,650	$ 43,129	$ 711,956	9.76	10.25%	$ 72,984	$ 79,179	$ 6,195
1935	Stores Equipment	$ 6,212	$ -	$ 1,899	$ -	$ 7,161	15.00	6.67%	$ 477	$ 930	$ 453
1940	Tools, Shop & Garage Equipment	$ 43,764	$ 461	$ 600	$ -	$ 43,603	10.00	10.00%	$ 4,360	$ 5,353	$ 993
1945	Measurement & Testing Equipment	$ 28,355	$ -	$ 14,934	$ -	$ 35,822	10.00	10.00%	$ 3,582	$ 3,833	$ 251
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,775	$ 125	$ -	$ -	$ 1,651	10.00	10.00%	$ 165	$ 165	-$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 115,103	$ 801	$ 5,516	$ -	$ 117,060	10.00	10.00%	$ 11,706	$ 17,989	$ 6,283
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 1,128,498	$ -	-$ 633,962	$ -	-$ 1,445,479	38.88	2.57%	-$ 37,178	-$ 36,513	$ 665
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 19,639,998**	**$ 163,454**	**$ 1,917,648**		**$ 20,514,792**			**$ 902,930**	**$ 873,981**	**-$ 28,949**
											-3.3%

Table 2-52 – 2018 MIFRS Depreciation and Amortization Continuity

Year 2018

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 340,853	$ 110,348	$ 22,371	$ 1,433	$ 242,407	5.00	20.00%	**$ 48,481**	$ 46,326	**-$ 2,156**
1612	Land Rights (Formally known as Account 1906)	$ 113,118	$ -	$ -	$ -	$ 113,118		0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 483,691	$ 24,288	$ 14,841	$ -	$ 466,824	20.62	4.85%	**$ 22,639**	$ 34,126	**$ 11,486**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 1,864,120	$ 13,223	$ 205,188	$ -	$ 1,953,490	45.64	2.19%	**$ 42,802**	$ 55,453	**$ 12,651**
1835	Overhead Conductors & Devices	$ 1,899,438	$ 1,361	$ 157,462	$ -	$ 1,976,808	58.73	1.70%	**$ 33,659**	$ 40,278	**$ 6,619**
1840	Underground Conduit	$ 4,166,509	$ -	$ 116,780	$ -	$ 4,224,898	46.41	2.15%	**$ 91,034**	$ 94,253	**$ 3,218**
1845	Underground Conductors & Devices	$ 4,022,863	$ 54,298	$ 245,072	$ 24,475	$ 4,103,338	31.01	3.22%	**$ 132,323**	$ 150,303	**$ 17,980**
1850	Line Transformers	$ 4,164,507	$ 3,853	$ 320,205	$ 16,498	$ 4,329,007	40.47	2.47%	**$ 106,968**	$ 133,936	**$ 26,968**
1855	Services (Overhead & Underground)	$ 1,395,488	$ -	$ 133,625	$ -	$ 1,462,300	38.60	2.59%	**$ 37,883**	$ 47,032	**$ 9,149**
1860	Meters	$ 1,643,853	$ 539	$ 143,901	$ 20,864	$ 1,725,696	10.05	9.95%	**$ 171,711**	$ 130,623	**-$ 41,089**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 110,842	$ -	$ -	$ -	$ 110,842	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,853,842	$ -	$ 69,750	$ -	$ 1,888,718	26.39	3.79%	**$ 71,569**	$ 80,267	**$ 8,697**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 98,707	$ 10,360	$ 29,417	$ -	$ 103,057	10.00	10.00%	**$ 10,306**	$ 12,990	**$ 2,685**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 97,527	$ 10,499	$ 13,899	$ 14,565	$ 101,260	5.00	20.00%	**$ 20,252**	$ 17,901	**-$ 2,351**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 665,088	$ -	$ 293,225	$ 45,014	$ 834,207	10.66	9.38%	**$ 78,256**	$ 80,851	**$ 2,595**
1935	Stores Equipment	$ 8,111	$ 1,722	$ -	$ -	$ 6,388	10.00	10.00%	**$ 639**	$ 784	**$ 145**
1940	Tools, Shop & Garage Equipment	$ 44,364	$ 2,647	$ 15,957	$ -	$ 49,696	10.00	10.00%	**$ 4,970**	$ 5,720	**$ 751**
1945	Measurement & Testing Equipment	$ 43,289	$ 560	$ 1,911	$ -	$ 43,685	10.00	10.00%	**$ 4,369**	$ 4,576	**$ 207**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,775	$ 125	$ -	$ -	$ 1,651	10.00	10.00%	**$ 165**	$ 165	**-$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 120,619	$ 2,079	$ 4,166	$ -	$ 120,623	10.00	10.00%	**$ 12,062**	$ 17,490	**$ 5,428**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 1,762,460	$ -	-$ 205,712	$ -	-$ 1,865,316	40.67	2.46%	**-$ 45,865**	-$ 47,366	**-$ 1,502**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 21,398,798**	**$ 235,900**	**$ 1,582,058**	**$ 122,849**	**$ 22,015,352**			**$ 844,225**	**$ 905,707**	**$ 61,482**
											6.8%

Table 2-53 – 2019 MIFRS Depreciation and Amortization Continuity

Year 2019

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 361,791	$ 130,537	$ 49,155	$ 4,177	$ 257,919	5.00	20.00%	**$ 51,584**	$ 38,302	**-$ 13,282**
1612	Land Rights (Formally known as Account 1906)	$ 113,118	$ -	$ 22,600	$ -	$ 124,418		0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 498,532	$ 24,288	$ 20,345	$ -	$ 484,416	21.03	4.76%	**$ 23,035**	$ 34,927	**$ 11,893**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,069,307	$ 13,223	$ 196,315	$ -	$ 2,154,242	45.58	2.19%	**$ 47,263**	$ 59,587	**$ 12,324**
1835	Overhead Conductors & Devices	$ 2,056,900	$ 1,361	$ 208,091	$ -	$ 2,159,585	58.85	1.70%	**$ 36,696**	$ 43,324	**$ 6,628**
1840	Underground Conduit	$ 4,283,288	$ -	$ 102,298	$ -	$ 4,334,437	46.04	2.17%	**$ 94,145**	$ 96,404	**$ 2,259**
1845	Underground Conductors & Devices	$ 4,243,460	$ 54,298	$ 185,171	$ -	$ 4,281,748	31.03	3.22%	**$ 137,987**	$ 155,356	**$ 17,368**
1850	Line Transformers	$ 4,468,214	$ 3,597	$ 266,310	$ 21,938	$ 4,608,741	35.28	2.83%	**$ 130,633**	$ 140,375	**$ 9,742**
1855	Services (Overhead & Underground)	$ 1,529,112	$ -	$ 90,318	$ -	$ 1,574,271	38.69	2.58%	**$ 40,689**	$ 49,972	**$ 9,283**
1860	Meters	$ 1,766,891	$ 539	$ 105,516	$ 45,022	$ 1,841,621	15.98	6.26%	**$ 115,245**	$ 135,231	**$ 19,986**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 110,842	$ -	$ -	$ -	$ 110,842	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,923,593	$ -	$ 35,528	$ -	$ 1,941,357	26.37	3.79%	**$ 73,620**	$ 82,093	**$ 8,473**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 128,125	$ 12,433	$ 19,450	$ 13,640	$ 132,237	10.00	10.00%	**$ 13,224**	$ 14,080	**$ 856**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 96,860	$ 5,954	$ 30,296	$ 5,548	$ 108,828	5.00	20.00%	**$ 21,766**	$ 19,205	**-$ 2,561**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 913,299	$ 54,703	$ 32,823	$ 11,785	$ 880,901	10.56	9.47%	**$ 83,419**	$ 83,357	**-$ 61**
1935	Stores Equipment	$ 8,111	$ 2,279	$ -	$ -	$ 5,832	10.00	10.00%	**$ 583**	$ 600	**$ 17**
1940	Tools, Shop & Garage Equipment	$ 60,321	$ 3,747	$ 1,014	$ -	$ 57,081	10.00	10.00%	**$ 5,708**	$ 5,970	**$ 262**
1945	Measurement & Testing Equipment	$ 45,200	$ 560	$ 2,997	$ -	$ 46,139	10.00	10.00%	**$ 4,614**	$ 4,821	**$ 207**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,775	$ 125	$ -	$ -	$ 1,651	10.00	10.00%	**$ 165**	$ 165	**-$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 124,784	$ 9,202	$ -	$ -	$ 115,582	10.00	10.00%	**$ 11,558**	$ 13,962	**$ 2,404**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 1,968,172	$ -	-$ 115,021	-$ 45,082	-$ 2,048,223	40.83	2.45%	**-$ 50,165**	-$ 51,039	**-$ 874**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 22,858,008**	**$ 316,846**	**$ 1,253,207**		**$ 23,196,279**			**$ 841,770**	**$ 926,694**	**$ 84,924**
											9.2%

Table 2-54 – 2020 MIFRS Depreciation and Amortization Continuity

Year 2020

		Book Values				Service Lives		Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 406,769	$ 254,543	$ 21,059	$ 23,514	$ 174,513	5.00	20.00%	**$ 34,903**	$ 29,488	**-$ 5,414**
1612	Land Rights (Formally known as Account 1906)	$ 135,718	$ -	$ 4,089	$ -	$ 137,762	-	0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 518,877	$ 24,288	$ -	$ -	$ 494,589	21.81	4.59%	**$ 22,677**	$ 30,792	**$ 8,115**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,265,622	$ 13,223	$ 214,652	$ 16,938	$ 2,368,194	45.53	2.20%	**$ 52,014**	$ 63,819	**$ 11,805**
1835	Overhead Conductors & Devices	$ 2,264,991	$ 1,361	$ 557,740	$ 1,545	$ 2,543,272	59.08	1.69%	**$ 43,048**	$ 49,760	**$ 6,712**
1840	Underground Conduit	$ 4,385,586	$ -	$ 178,234	$ -	$ 4,474,704	45.62	2.19%	**$ 98,086**	$ 99,233	**$ 1,147**
1845	Underground Conductors & Devices	$ 4,428,631	$ 54,298	$ 144,008	$ -	$ 4,446,337	30.78	3.25%	**$ 144,455**	$ 159,996	**$ 15,540**
1850	Line Transformers	$ 4,712,586	$ 3,424	$ 424,239	$ 58,743	$ 4,950,653	30.01	3.33%	**$ 164,967**	$ 147,085	**-$ 17,882**
1855	Services (Overhead & Underground)	$ 1,619,431	$ -	$ 51,180	$ -	$ 1,645,021	53.38	1.87%	**$ 30,817**	$ 52,690	**$ 21,873**
1860	Meters	$ 1,827,385	$ -	$ 74,360	$ 18,049	$ 1,873,589	13.85	7.22%	**$ 135,277**	$ 138,079	**$ 2,801**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 110,842	$ 539	$ -	$ 4,473	$ 112,539	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,959,121	$ 1,164	$ 25,149	$ -	$ 1,970,531	19.77	5.06%	**$ 99,673**	$ 83,677	**-$ 15,996**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 133,934	$ 12,433	$ -	$ -	$ 121,501	5.00	20.00%	**$ 24,300**	$ 12,158	**-$ 12,142**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 121,609	$ 20,926	$ 44,717	$ 4,101	$ 125,093	8.00	12.50%	**$ 15,637**	$ 22,095	**$ 6,458**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 934,337	$ 74,897	$ 181,741	$ 70,204	$ 985,413	13.46	7.43%	**$ 73,210**	$ 85,444	**$ 12,233**
1935	Stores Equipment	$ 8,111	$ 3,614	$ -	$ -	$ 4,497	10.00	10.00%	**$ 450**	$ 481	**$ 31**
1940	Tools, Shop & Garage Equipment	$ 61,335	$ 8,934	$ -	$ 1,178	$ 52,990	10.00	10.00%	**$ 5,299**	$ 5,424	**$ 125**
1945	Measurement & Testing Equipment	$ 48,197	$ 560	$ 3,769	$ 424	$ 49,735	10.00	10.00%	**$ 4,973**	$ 5,139	**$ 166**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,775	$ 125	$ -	$ -	$ 1,651	10.00	10.00%	**$ 165**	$ 165	**-$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 124,784	$ 52,159	$ -	$ -	$ 72,625	10.00	10.00%	**$ 7,262**	$ 7,590	**$ 328**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 2,038,111	$ -	-$ 239,979	-$ 4,458	-$ 2,160,329	46.92	2.13%	**-$ 46,043**	-$ 54,748	**-$ 8,705**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 24,054,186**	**$ 526,487**	**$ 1,684,959**	**$ 194,710**	**$ 24,467,534**			**$ 911,171**	**$ 938,368**	**$ 27,196**
											2.9%

Table 2-55 – 2021 MIFRS Depreciation and Amortization Continuity

Year 2021

		Book Values				Service Lives		Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 404,315	$ 259,101	$ 22,675	$ 137,596	$ 225,349	5.00	20.00%	**$ 45,070**	$ 29,791	**-$ 15,279**
1612	Land Rights (Formally known as Account 1906)	$ 139,807	$ -	$ -	$ -	$ 139,807	-	0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 518,877	$ 83,823	$ -	$ 61,859	$ 465,984	19.94	5.02%	**$ 23,369**	$ 25,004	**$ 1,635**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,463,337	$ 17,567	$ 315,340	$ -	$ 2,603,440	45.47	2.20%	**$ 57,256**	$ 68,822	**$ 11,566**
1835	Overhead Conductors & Devices	$ 2,821,186	$ 1,361	$ 411,605	$ -	$ 3,025,628	59.19	1.69%	**$ 51,117**	$ 57,713	**$ 6,596**
1840	Underground Conduit	$ 4,563,821	$ -	$ 365,650	$ -	$ 4,746,646	45.55	2.20%	**$ 104,207**	$ 104,346	**$ 138**
1845	Underground Conductors & Devices	$ 4,572,639	$ 54,298	$ 383,757	$ -	$ 4,710,220	30.67	3.26%	**$ 153,577**	$ 167,554	**$ 13,977**
1850	Line Transformers	$ 5,078,082	$ 3,336	$ 401,986	$ 74,136	$ 5,312,808	29.98	3.34%	**$ 177,212**	$ 157,686	**-$ 19,526**
1855	Services (Overhead & Underground)	$ 1,670,611	$ -	$ 135,998	$ -	$ 1,738,610	53.81	1.86%	**$ 32,310**	$ 53,584	**$ 21,274**
1860	Meters	$ 1,883,696	$ 539	$ 177,597	$ 1,861	$ 1,972,886	14.36	6.96%	**$ 137,388**	$ 142,511	**$ 5,123**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 106,368	$ -	$ -	$ -	$ 106,368	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 1,984,270	$ 1,164	$ 5,633	$ -	$ 1,985,922	18.42	5.43%	**$ 107,813**	$ 84,193	**-$ 23,620**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 133,934	$ 36,231	$ -	$ -	$ 97,704	5.00	20.00%	**$ 19,541**	$ 10,034	**-$ 9,506**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 162,226	$ 42,422	$ 29,188	$ 65,896	$ 167,346	8.00	12.50%	**$ 20,918**	$ 23,891	**$ 2,973**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 1,045,874	$ 74,897	$ -	$ -	$ 970,977	10.00	10.00%	**$ 97,098**	$ 88,322	**-$ 8,776**
1935	Stores Equipment	$ 8,111	$ 3,614	$ -	$ -	$ 4,497	10.00	10.00%	**$ 450**	$ 481	**$ 31**
1940	Tools, Shop & Garage Equipment	$ 60,157	$ 9,827	$ 700	$ -	$ 50,680	10.00	10.00%	**$ 5,068**	$ 4,854	**-$ 214**
1945	Measurement & Testing Equipment	$ 51,542	$ 560	$ 171	$ 761	$ 51,449	10.00	10.00%	**$ 5,145**	$ 4,966	**-$ 179**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,775	$ 125	$ 801	$ -	$ 2,051	10.00	10.00%	**$ 205**	$ 172	**-$ 33**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 124,784	$ 71,602	$ 7,024	$ 1,826	$ 57,607	10.00	10.00%	**$ 5,761**	$ 4,892	**-$ 869**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 2,273,632	$ -	-$ 349,139	-$ 5,524	-$ 2,450,963	39.49	2.53%	**-$ 62,065**	-$ 61,687	**$ 378**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 25,544,435**	**$ 660,465**	**$ 1,908,986**	**$ 338,412**	**$ 26,007,669**			**$ 981,440**	**$ 967,130**	**-$ 14,310**
											-1.5%

Table 2-56 – 2022 MIFRS Depreciation and Amortization Continuity

Year 2022

		Book Values				Service Lives		Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [4]
		a	b	c	d	= a-b+(0.5*(c+d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 289,393	$ 136,357	$ 25,735	$ 43,526	$ 187,666	5.00	20.00%	**$ 37,533**	$ 28,794	**-$ 8,739**
1612	Land Rights (Formally known as Account 1906)	$ 139,807	$ -	$ -	$ -	$ 139,807	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 22,655	$ -	$ -	$ -	$ 22,655	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 457,017	$ 76,425	$ 4,394	$ -	$ 382,790	20.21	4.95%	**$ 18,941**	$ 23,212	**$ 4,271**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 2,778,677	$ 17,567	$ 176,343	$ -	$ 2,849,282	45.44	2.20%	**$ 62,704**	$ 74,285	**$ 11,581**
1835	Overhead Conductors & Devices	$ 3,232,791	$ 1,361	$ 91,719	$ -	$ 3,277,290	59.22	1.69%	**$ 55,341**	$ 61,907	**$ 6,566**
1840	Underground Conduit	$ 4,929,470	$ -	$ 1,625,359	$ -	$ 5,742,150	46.22	2.16%	**$ 124,235**	$ 124,172	**-$ 63**
1845	Underground Conductors & Devices	$ 4,956,396	$ 54,298	$ 340,048	$ -	$ 5,072,122	30.83	3.24%	**$ 164,519**	$ 183,858	**$ 19,338**
1850	Line Transformers	$ 5,405,933	$ 3,031	$ 539,435	$ 57,384	$ 5,701,312	30.02	3.33%	**$ 189,917**	$ 165,148	**-$ 24,769**
1855	Services (Overhead & Underground)	$ 1,806,609	$ -	$ 50,731	$ -	$ 1,831,974	53.72	1.86%	**$ 34,102**	$ 57,250	**$ 23,148**
1860	Meters	$ 2,059,431	$ 539	$ 20,057	$ 2,758	$ 2,070,300	13.96	7.16%	**$ 148,302**	$ 146,266	**-$ 2,036**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ 106,368	$ -	$ -	$ -	$ 106,368	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 1,989,903	$ 1,164	$ 38,033	$ -	$ 2,007,755	19.02	5.26%	**$ 105,560**	$ 78,196	**-$ 27,364**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 133,934	$ 40,747	$ 6,335	$ -	$ 96,355	5.00	20.00%	**$ 19,271**	$ 8,881	**-$ 10,390**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 125,518	$ 7,830	$ 41,159	$ 18,593	$ 147,564	8.00	12.50%	**$ 18,445**	$ 25,840	**$ 7,395**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 1,045,874	$ 74,897	$ -	$ -	$ 970,977	13.36	7.49%	**$ 72,678**	$ 88,322	**$ 15,644**
1935	Stores Equipment	$ 8,111	$ 3,614	$ -	$ -	$ 4,497	10.00	10.00%	**$ 450**	$ 399	**-$ 51**
1940	Tools, Shop & Garage Equipment	$ 60,856	$ 16,750	$ -	$ -	$ 44,107	10.00	10.00%	**$ 4,411**	$ 4,403	**-$ 8**
1945	Measurement & Testing Equipment	$ 50,952	$ 5,039	$ 19,019	$ -	$ 55,422	10.00	10.00%	**$ 5,542**	$ 5,953	**$ 411**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 2,576	$ 125	$ 2,243	$ -	$ 3,573	10.00	10.00%	**$ 357**	$ 291	**-$ 67**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 129,982	$ 93,150	$ 2,399	$ -	$ 38,032	10.00	10.00%	**$ 3,803**	$ 3,762	**-$ 41**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 2,617,247	$ -	-$ 62,566	$ -	-$ 2,648,530	39.64	2.52%	**-$ 66,815**	-$ 66,647	**$ 167**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
	Total	**$ 27,115,008**	**$ 532,893**	**$ 2,920,445**	**$ 122,260**	**$ 28,103,468**			**$ 999,298**	**$ 1,014,294**	**$ 14,996**
											1.5%

Table 2-57 – 2023 Bridge MIFRS Depreciation and Amortization Continuity

Year 2023

		Book Values				Service Lives		Expense		
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets,	Variance [4]
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 271,602	$ 136,357	$ 15,525	$ 143,007	5.00	20.00%	**$ 28,601**	$ 27,080	**-$ 1,521**
1612	Land Rights (Formally known as Account 1906)	$ 139,807	$ -	$ -	$ 139,807	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 22,655	$ -	$ -	$ 22,655	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 461,411	$ 76,425	$ -	$ 384,987	20.21	4.95%	**$ 19,049**	$ 23,258	**$ 4,209**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 2,955,020	$ 17,567	$ 131,780	$ 3,003,343	45.44	2.20%	**$ 66,095**	$ 77,615	**$ 11,521**
1835	Overhead Conductors & Devices	$ 3,324,510	$ 1,361	$ 95,898	$ 3,371,099	59.22	1.69%	**$ 56,925**	$ 63,434	**$ 6,509**
1840	Underground Conduit	$ 6,554,830		$ 465,369	$ 6,787,514	46.22	2.16%	**$ 146,852**	$ 144,303	**-$ 2,549**
1845	Underground Conductors & Devices	$ 5,296,444	$ 54,298	$ 489,513	$ 5,486,903	30.83	3.24%	**$ 177,973**	$ 188,332	**$ 10,360**
1850	Line Transformers	$ 5,887,985	$ 2,943	$ 896,339	$ 6,333,211	30.02	3.33%	**$ 210,966**	$ 182,551	**-$ 28,415**
1855	Services (Overhead & Underground)	$ 1,857,340	$ -	$ 95,951	$ 1,905,315	53.72	1.86%	**$ 35,468**	$ 59,559	**$ 24,092**
1860	Meters	$ 2,076,731	$ 539	$ 205,289	$ 2,178,837	13.96	7.16%	**$ 156,077**	$ 152,720	**-$ 3,357**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ 106,368	$ -	$ -	$ 106,368	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,027,935	$ 119,056	$ 75,801	$ 1,946,780	19.02	5.26%	**$ 102,354**	$ 73,750	**-$ 28,604**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 140,269	$ 60,415	$ 5,000	$ 82,355	5.00	20.00%	**$ 16,471**	$ 7,337	**-$ 9,134**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 148,084	$ 7,830	$ 11,695	$ 146,101	8.00	12.50%	**$ 18,263**	$ 28,127	**$ 9,864**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1930	Transportation Equipment	$ 1,045,874	$ 74,897	$ -	$ 970,977	13.36	7.49%	**$ 72,678**	$ 85,858	**$ 13,180**
1935	Stores Equipment	$ 8,111	$ 4,978	$ 2,000	$ 4,133	10.00	10.00%	**$ 413**	$ 354	**-$ 59**
1940	Tools, Shop & Garage Equipment	$ 60,856	$ 17,266	$ 2,000	$ 44,591	10.00	10.00%	**$ 4,459**	$ 4,330	**-$ 129**
1945	Measurement & Testing Equipment	$ 69,970	$ 5,039	$ 2,778	$ 66,320	10.00	10.00%	**$ 6,632**	$ 6,211	**-$ 421**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 4,819	$ 125	$ 7,584	$ 8,487	10.00	10.00%	**$ 849**	$ 1,098	**$ 249**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 132,381	$ 94,424	$ 2,000	$ 38,957	10.00	10.00%	**$ 3,896**	$ 3,779	**-$ 117**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 2,679,813	$ -	-$ 451,067	-$ 2,905,346	39.64	2.52%	**-$ 73,293**	-$ 72,496	**$ 798**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
	Total	**$ 29,913,193**	**$ 673,519**	**$ 2,053,455**	**$ 30,266,402**			**$ 1,050,728**	**$ 1,057,203**	**$ 6,475**
										0.6%

Table 2-58 – 2024 Test MIFRS Depreciation and Amortization Continuity

Year 2024

		Book Values				Service Lives		Expense		
Account	**Description**	**Opening Book Value of Assets**	**Less Fully Depreciated [1]**	**Current Year Additions**	**Net Amount of Assets to be Depreciated**	**Remaining Life of Assets Existing [2]**	**Depreciation Rate Assets**	**Depreciation Expense on Assets [3]**	**Depreciation Expense per Appendix 2-BA Fixed Assets,**	**Variance [4]**
		a	b	c	d = a-b+0.5*c	e	f = 1/e	g = d/e	h	q = h-g
1609	Capital Contributions Paid	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 287,127	$ 136,357	$ 197,380	$ 249,460	5.00	20.00%	**$ 49,892**	$ 42,045	**-$ 7,847**
1612	Land Rights (Formally known as Account 1906)	$ 139,807	$ -	$ -	$ 139,807	-	0.00%	$ -	$ -	$ -
1805	Land	$ 22,655	$ -	$ -	$ 22,655	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 461,411	$ 76,425	$ 7,194	$ 388,584	20.21	4.95%	**$ 19,227**	$ 21,171	**$ 1,944**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 3,080,200	$ 17,567	$ 147,900	$ 3,136,583	45.44	2.20%	**$ 69,027**	$ 80,668	**$ 11,641**
1835	Overhead Conductors & Devices	$ 3,416,008	$ 1,361	$ 227,478	$ 3,528,387	59.22	1.69%	**$ 59,581**	$ 66,145	**$ 6,564**
1840	Underground Conduit	$ 7,020,199	$ -	$ 673,960	$ 7,357,179	46.22	2.16%	**$ 159,177**	$ 155,070	**-$ 4,107**
1845	Underground Conductors & Devices	$ 5,785,957	$ 54,298	$ 511,536	$ 5,987,427	30.83	3.24%	**$ 194,208**	$ 200,213	**$ 6,005**
1850	Line Transformers	$ 6,767,324	$ 2,943	$ 793,138	$ 7,160,950	30.02	3.33%	**$ 238,539**	$ 207,529	**-$ 31,010**
1855	Services (Overhead & Underground)	$ 1,953,290	$ -	$ 353,578	$ 2,130,080	53.72	1.86%	**$ 39,652**	$ 65,268	**$ 25,616**
1860	Meters	$ 2,263,220	$ 539	$ 251,499	$ 2,388,431	13.96	7.16%	**$ 171,091**	$ 161,729	**-$ 9,362**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ 106,368	$ -	$ -	$ 106,368	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 2,103,296	$ 119,056	$ 296,000	$ 2,132,240	19.02	5.26%	**$ 112,105**	$ 81,209	**-$ 30,896**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 145,269	$ 60,415	$ 30,000	$ 99,855	5.00	20.00%	**$ 19,971**	$ 8,139	**-$ 11,832**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 155,779	$ 7,830	$ 58,000	$ 176,949	8.00	12.50%	**$ 22,119**	$ 31,318	**$ 9,199**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1930	Transportation Equipment	$ 1,040,874	$ 74,897	$ 93,815	$ 1,012,885	13.36	7.49%	**$ 75,815**	$ 81,489	**$ 5,674**
1935	Stores Equipment	$ 10,111	$ 4,978	$ 2,000	$ 6,133	10.00	10.00%	**$ 613**	$ 490	**-$ 123**
1940	Tools, Shop & Garage Equipment	$ 62,856	$ 17,266	$ 6,500	$ 48,841	10.00	10.00%	**$ 4,884**	$ 4,431	**-$ 453**
1945	Measurement & Testing Equipment	$ 72,749	$ 5,039	$ 24,222	$ 79,821	10.00	10.00%	**$ 7,982**	$ 7,038	**-$ 944**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 12,403	$ 125	$ 1,000	$ 12,779	10.00	10.00%	**$ 1,278**	$ 1,856	**$ 578**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 134,381	$ 94,424	$ 2,000	$ 40,957	10.00	10.00%	**$ 4,096**	$ 3,736	**-$ 360**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 3,130,879	$ -	-$ 718,936	-$ 3,490,348	39.64	2.52%	**-$ 88,051**	-$ 85,531	**$ 2,521**
2005	Property Under Finance Lease	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
	Total	**$ 31,910,408**	**$ 673,519**	**$ 2,958,264**	**$ 32,716,021**			**$ 1,161,206**	**$ 1,134,013**	**-$ 27,193**
										-2.4%

2.3.3 ASSET RETIREMENT OBLIGATIONS

OHL confirms that there are no asset retirement obligations that are part of its application.

2.3.4 HISTORICAL DEPRECIATION PRACTICE AND PROPOSAL FOR TEST YEAR

OHL is not proposing changes to its historical depreciation practice for the Test year.

2.3.5 DEPRECIATION POLICY

OHL's depreciation policy is included in Appendix 2-B Depreciation Policy.

2.3.6 DEVIATIONS FROM DEPRECIATING SIGNIFICANT PARTS OF PP&E

OHL confirms that it depreciates significant parts of PP&E under MIFRS rules.

2.3.7 CHANGES TO DEPRECIATION POLICY SINCE LAST RE-BASING

OHL confirms that changes to the depreciation policy have been made since the last re-basing. OHL converted to MIFRS in 2015, retroactive to January 1st 2014 and has not rebased since. OHL now depreciates significant parts of PP&E under MIFRS rules.

OHL has completed Appendix 2-BB which can be found at Table 2-47 – Service Life Comparison to Kinectrics Report which details all asset service lives tied to UsoA. There are no service lives outside of the minimum and maximum TUL range from Kinectrics.

2.4 ALLOWANCE FOR WORKING CAPITAL

2.4.1 WORKING CAPITAL

This Schedule provides an overview of OHL's Allowance for Working Capital ("WCA"). In accordance with the OEB's Chapter 2 Filing Requirements for Electricity Distribution Rate. Applications, the allowance for working capital calculation used to determine the deemed return on equity should be presented. This Schedule provides yearly information on OHL's WCA, including detailed information on the Cost of Power calculation with pricing and consumption assumptions. OHL did not conduct a Lead/Lag study, and was not ordered by the OEB to do so.

OHL utilizes the OEB's default allowance for working capital ("WC"), which is set at 7.5% of the sum of the Cost of Power ("CoP") and Recoverable OM&A. OHL attests that the Cost of Power is determined by the split between Regulated Price Plan ("RPP") and non-RPP customers based on actual data, using current RPP prices and Uniform Transmission Rates ("UTR"). Table 2-59 –Working Capital Allowance 2014 to 2024 below presents the derivation of the allowance for working capital for the historical 2014-2022, as well as the 2023 Bridge and 2024 Test Year.

Table 2-59 –Working Capital Allowance 2014 to 2024

Working Capital Allowance	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Recoverable OM&A Expenses	3,255,183	3,224,934	3,287,582	3,317,207	3,323,900	3,200,271	3,442,073	3,197,840	3,380,858	3,639,401	3,812,695	4,235,523
Taxes Other than Income Taxes		-	-	-	-	14,349	36,763	41,103	41,256	41,686	43,008	44,298
Less Allocated Depreciation in OM&A	(60,470)	(53,409)	(68,841)	(78,947)	(83,833)	(89,283)	(94,914)	(96,653)	(98,795)	(99,368)	(97,851)	(95,304)
Total Eligible Distribution Expenses	**3,194,713**	**3,171,524**	**3,218,741**	**3,238,260**	**3,240,067**	**3,125,336**	**3,383,923**	**3,142,290**	**3,323,319**	**3,581,719**	**3,757,853**	**4,184,517**
Power Supply Expenses	27,763,022	26,967,661	29,745,385	33,273,556	29,609,584	27,833,754	29,083,782	32,771,802	29,029,339	30,671,964	29,356,772	29,298,887
Total Working Capital Expenses	**30,957,735**	**30,139,185**	**32,964,126**	**36,511,816**	**32,849,651**	**30,959,090**	**32,467,705**	**35,914,093**	**32,352,657**	**34,253,683**	**33,114,624**	**33,483,404**
Working Capital Factor	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	10.0%	7.5%
Working Capital Allowance	**$3,095,774**	**$3,013,919**	**$3,296,413**	**$3,651,182**	**$3,284,965**	**$3,095,909**	**$3,246,770**	**$3,591,409**	**$3,235,266**	**$3,425,368**	**$3,311,462**	**$2,511,255**

<u>Operation, Maintenance and Administration</u>

For more details on the OM&A expenses used in the table above, please see Exhibit 4.2.1.

2.4.2 COST OF POWER

The power supply expense for the 2024 Test Year uses forecasted monthly purchases kWh and peak kW calculated in the load forecast as described in Exhibit 3.1: Load Forecast. The components of OHL's Cost of Power ("CoP") are summarized in Table 2-60 – Summary of 2024 Test Year Cost of Power Expense below and detailed in accordance with the Filing Requirements.

The Cost of Power Expense details can also be found in App.2-ZA_Com. Exp. Forecast and App.2-ZB_Cost of Power of OHL's Chapter 2 Appendices.

Table 2-60 – Summary of 2024 Test Year Cost of Power Expense

2024 Test Year - Cop	
4705 -Power Purchased	$ 20,789,349
4707- Global Adjustment	$ 4,174,667
4708-Charges-WMS	$ 1,430,341
4714-Charges-NW	$ 2,369,730
4716-Charges-CN	$ 1,480,602
4750-Charges-LV	$ 913,949
4751-IESO SME	$ 65,021
Misc A/R or A/P	$ (1,924,771)
TOTAL	**$ 29,298,887**

For the 2024 Test Year, the commodity prices used in the calculation were prices published in the Board's Regulated Price Plan Price Report November 1, 2022, to October 31, 2023.

The commodity price for Regulated Price Plan ("RPP") customers was determined using Average RPP Supply Cost pricing of $0.09340 kWh for RPP customers.

The commodity price for non-RPP Class B customers was determined using Average Hourly Energy Price ("HOEP") of $0.05833 kWh for non-RPP customers and the Average Global Adjustment ("GA") of $0.03904 kWh for Class B non-RPP customers.

The commodity price for Class A customers was determined using the Average HOEP of $0.05833 kWh for non-RPP customers and an Average GA of $0.02290 based on OHL's historical GA amount and Peak Demand Factor ("PDF").

Should the Board publish a revised Regulated Price Plan Report prior to the Board's Decision in the application, OHL will update the electricity prices in the forecast.

The split between RPP and non-RPP was pro-rated using OHL's December 31, 2022, RRR filing as a basis of proration. Please refer to tab "2024 RPP non-RPP COP" of the OHL 2024 Load Forecast Model Excel file uploaded as part of the CoS for verification.

Table 2-61 - Split of 2024 Forecast RPP vs non-RPP kWh and kW

From 2022 RRR kWh, this is non-loss-adjusted data, METERED DATA					
	Total	**Class A**	**RPP**	**non-RPP**	**WMP**
Residential	95,371,627.72		94,267,764.31	1,103,863.41	
GS < 50	35,235,863.47		30,084,736.87	5,151,126.60	
GS > 50	136,159,366.09	66,370,348.91	10,829,685.43	56,423,159.46	2,536,172.29
Embedded Distributor	-				
Street Light	875,006.28		159,687.48	715,318.80	
Sentinel Light	99,742.97		99,742.97		
USL	375,339.19		375,339.19		
	268,116,945.72	66,370,348.91	135,816,956.26	63,393,468.27	2,536,172.29
	280,959,747.42				
2024 Forecast with losses	**New Loss factor**	**1.0479**			
	Total no losses	**Class A**	**RPP**	**non-RPP**	**WMP**
Residential	93,562,278.05		96,909,117.84	1,134,793.32	-
GS < 50	34,272,791.37		30,664,127.82	5,250,330.26	-
GS > 50	133,456,842.37	68,169,053.71	11,123,181.06	57,952,285.18	2,604,905.17
Embedded Distributor					
Street Light	883,782.06		169,014.80	757,100.42	-
Sentinel Light	99,920.03		104,706.20	-	-
USL	370,613.50		388,365.89	-	-
	262,646,227.37	68,169,053.71	139,358,513.60	65,094,509.19	2,604,905.17
with losses	275,226,981.67				
From 2022 RRR kW, no losses on Demand				**Loss Factor**	**WMP**
	Total	**Class A**	**RPP**	**non-RPP**	
Residential	-				
GS < 50	-				
GS > 50	317,681.46	127,034.69	36,991.82	148,121.80	5,533.15
Embedded Distributor	-				
Street Light	2,434.08		440.16	1,993.92	
Sentinel Light	278.20		278.20		
USL	-				
	320,393.74	127,034.69	37,710.18	150,115.72	5,533.15
2024 Forecast					
	Total no losses	**Class A**	**RPP**	**non-RPP**	**WMP**
Residential					
GS < 50					
GS > 50	313,258.95	125,266.21	36,476.85	146,059.77	5,456.12
Embedded Distributor					
Street Light	2,461.65		445.14	2,016.50	
Sentinel Light	277.70		277.70		
USL					
	315,998.30	125,266.21	37,199.69	148,076.27	5,456.12

2.4.3 MOST RECENT APPROVED CHARGES

The Cost of Power prices for Regulatory Items and UTRs used in the 2024 Test Year COP calculation are as follows:

The most recent Transmission Network and Transmission Connection are taken from the 2024 RTSR Workform.

The Wholesale Market Service (“WMS”) charge of $0.0041 as established in the OEB EB-2022-0269 Decision and Order.

Class B Capacity Based Response charge of $0.0004 as established in the OEB EB-2022-0269 Decision and Order.

Rural and Remote Electricity Rate Protection (“RRRP”) charge of $0.0007 as established in the OEB EB-2022-0269 Decision and Order.

The most recent LV rates are taken from the 2024 RTSR Workform.

A Smart Meter Entity charge of $0.42 was used as established in the OEB EB-2022-0137.

2.5 DISTRIBUTION SYSTEM PLAN

OHL’s Distribution System Plan is included in Appendix 2-C.

2.6 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

OHL is not proposing any ACM projects in its 2024 Cost of Service application.

2.7 ADDITION OF ACM AND ICM PROJECT ASSETS TO RATE BASE

This section is not applicable as OHL has not previously been approved for an ACM or ICM project.

2.8 CAPITALIZATION

2.8.1 CAPITALIZATION POLICY

OHL’s Capitalization Policy is included in Appendix 2-A.

2.8.2 OVERHEAD COSTS

OHL has completed Chapter 2 Appendices, Appendix 2-D.

2.8.3 BURDEN RATES

OHL's burden rates are determined as part of its internal budget process. OHL has identified the burden rates related to the capitalization costs of self-constructed assets in the table below. The burden rates have not significantly changed since OHL's last rebasing application.

Table 2-62 – Burden Rates

Overhead Type	2014 Board Approved	2014 Actuals MIFRS	2015 Actuals MIFRS	2016 Actuals MIFRS	2017 Actuals MIFRS	2018 Actuals MIFRS	2019 Actuals MIFRS	2020 Actuals MIFRS	2021 Actuals MIFRS	2022 Actuals MIFRS	2023 Bridge MIFRS	2024 Test MIFRS
Lines Labour Overhead	62%	62%	62%	62%	64%	64%	64%	62%	67%	71%	66%	69%
Engineering Labour Overhead	47%	47%	47%	47%	49%	49%	49%	52%	59%	65%	53%	54%
Material Overhead	25%	25%	25%	20%	20%	20%	20%	20%	20%	20%	20%	20%
Vehicle Rates per hour												
Under 3 tons - pickups/vans	$20	$20	$15	$15	$15	$15	$20	$15	$10	$15	$15	$20
Under 3 tons - dump	$15	$15	$10	$10	$15	$25	$20	$20	$10	$15	$15	$15
Over 3 tons	$30	$30	$35	$35	$40	$40	$40	$45	$20	$35	$35	$45

2.9 INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

OHL does not have costs of eligible investments for the connection of qualifying generation facilities.

APPENDIX 2-A CAPITALIZATION POLICY

Orangeville Hydro	Policy No: FN-006 Motion: 1157	Date Issued: June 4, 1998 Date Revised: September 21, 2023
Capitalization Policy		

POLICY STATEMENT & PURPOSE

It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital requests for projects that enhance or improve the efficiency of the Company's assets. The policy describes the process used for determining if expenditures should be capitalized or expensed. A materiality amount is used and any expenditure below that threshold will be expensed to operations in the current year.

GUIDELINES

Capital Assets or PP&E

Property, plant and equipment are tangible items that:

(a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and

(b) are expected to be used during more than one period.

Where parts of an item of PP&E have different estimated economic useful lives, they

should be accounted for as separate items (major components) of PP&E.

Items such as spare parts, stand-by equipment and servicing equipment are recognised in accordance with this IFRS when they meet the definition of property, plant and equipment. Otherwise, such items are classified as inventory.

Intangible Assets

Intangible assets are an identifiable non-monetary asset without physical substance that:

(a) are held for use in the production or supply of goods or services, for rental to others, or for administrative purposes; and

(b) are expected to be used during more than one period.

Repair

A repair is a cost incurred to maintain the service potential of a capital asset. Expenditures for repairs are expensed to the current operating period. Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

MATERIALITY

All additions to capital assets and betterments will be capitalized subject to materiality limits as set out in this policy. At times the administrative costs of capitalizing an asset may outweigh the intended benefits. While the expenditure may meet the definition to qualify as a capital asset, a level is set, which if an expenditure falls below, it is not capitalized but charged to expense in the current period. This level is known as a materiality limit.

Materiality Limits

Identifiable Assets

Distribution Plant	$ 1,000
General Plant	$ 1,000

Identifiable Assets
An identifiable capital asset is an asset that has a sufficiently high unit cost and is easily identifiable for the asset to be individually tracked and recorded.

Similar assets may be grouped together when purchased, which will cause them to be above the materiality limit (for example 10 chairs at $125.00 each).

CAPITAL ASSET RECORDS

Items of property, plant and equipment recognized as assets are measured initially at cost. The cost of an item of property, plant, and equipment is comprised of:

- its purchase price, including import duties and non-refundable purchase taxes, after deducting trade discounts and rebates;
- any costs 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; and
- the initial estimate of the costs of dismantling and removing the item and restoring the site on which it is located, the obligation for which an entity incurs either when the item is acquired or as a consequence of having used the item during a particular period for purposes other than to produce inventories.

Examples of directly attributable costs (which are eligible for capitalization):

- costs of employee benefits arising directly from the construction or acquisition of the item of PP&E;
- costs of site preparation;
- initial delivery and handling costs;
- installation and assembly costs;
- costs of testing whether the asset is functioning properly, after deducting the net proceeds from selling any items produced while bringing the asset to that location and condition; and
- professional fees.

The cost of an item of property, plant and equipment shall be recognised as an asset if, and only if:

(a) it is probable that future economic benefits associated with the item will flow to the entity; and

(b) the cost of the item can be measured reliably.

Subsequent Costs

Parts of some items of property, plant and equipment may require replacement at regular intervals. Items of property, plant and equipment may also be acquired to make a less frequently recurring replacement, such as replacing the interior walls of a building, or to make a non-recurring replacement. Under the recognition principle an entity recognizes in the carrying amount of an item of property, plant and equipment the cost of replacing part of such an item when that cost is incurred if the recognition criteria are met. The carrying amount of those parts that are replaced is derecognized.

Derecognition

If an entity recognizes in the carrying amount of an item of property, plant and equipment the cost of a replacement for a component of the item, then it derecognizes the carrying amount of the component regardless of whether the component had been depreciated separately. If it is not practicable for an entity to determine the carrying amount of the component, it may use the cost of the replacement as an indication of what the cost of the component was at the time it was acquired or constructed.

Amortization

Major components of capital assets and intangibles are generally amortized based on a method and life set by Orangeville Hydro which is considered a suitable indicator of estimated useful life for the electricity distribution industry (refer to FN-007 – Depreciation Policy). The half year rule is utilized for amortization purposes, with a half year of amortization being recorded in the year of acquisition and a half year being recorded in the year of disposal.

Work in Process
Capital assets or intangibles that are included in incomplete jobs at year-end are considered work in process. These assets are recognized as capital assets or intangibles and amortized when the asset is capable of operating in the manner intended by management.

Disposals and Write Offs
For assets taken out of service, the asset component cost and the related accumulated amortization is removed from the records. Any difference between the proceeds and the unamortized asset component cost including removal costs are recorded as a gain or loss in the year of disposal.

To determine if an asset should be capitalized or expensed as a repair, the following questions should be asked:

- Is there an increase in the previously assessed physical output or service capacity of the asset?
- Are there significantly lower associated operating costs (efficiency)?
- Is the original useful life of the asset extended?
- Is the quality or efficiency of the output improved?

If at least one of these questions is answered “Yes”, then it is a betterment.

POLICY COMPLIANCE

All current practices will comply with OEB Accounting Procedures Handbook and International Financial Reporting Standards (IFRS). Employees must report incidents of non-compliance relating to this policy in a timely manner to the Policy Owner. Non-compliance of a serious nature will be immediately reported to the President. Determination of non-compliance issues of a serious nature will be the responsibility of the Policy Owner.

Orangeville Hydro Policy and Procedures			
Topic	**Capitalization Policy**	Number	FN-006
Category	Finance	Revision Number	3
Revised by	Suzanne Presseault, Senior Accountant	Issued and Effective	June 4, 1998
Reviewed by	Amy Long, CFO	Revision Issued and Effective	September 21, 2023
Approved by	Rob Koekkoek, President		

APPENDIX 2-B DEPRECIATION POLICY

Orangeville Hydro	Policy No: FN-007 Motion: 1157	Date Issued: October 24, 2013 Date Revised: September 21, 2023
Depreciation Policy		

POLICY STATEMENT & PURPOSE

It is the policy of the company to maintain strong financial control over expenditures for capital assets by evaluating and approving capital requests for projects that enhance or improve the efficiency of the Company's assets. These capital assets are expected to provide future economic benefits for more than one year; therefore these capitalized costs are allocated over the estimated useful life of the assets through amortization. This policy describes the process used for depreciating all capital assets that have been put into service. The intent is to ensure that PP&E and intangible assets are properly depreciated and amortized in accordance with International Financial Reporting Standards (IFRS).

HISTORY

Prior to 2012, Orangeville Hydro Limited (OHL) followed Canadian Generally Accepted Accounting Principles (CGAAP) for the purpose of recording capital assets. OHL recorded Property, Plant and Equipment as pooled assets based on major accounting classes in the year of acquisition. In 2012 OHL changed the useful lives of asset classes based on the Depreciation Study for Use by Electricity Distributors (EB-2010-0178), (the "Kinectrics Report"*)* and the overhead policy was revised January 1, 2013, similar to IFRS policies. OHL reviewed this study as well as applied its professional judgment to determine revised useful lives for all capital assets, including a new level of componentization.

OHL completed sufficient detailed accounting work in these areas to prepare for transition to International Financial Reporting Standards (IFRS), and made these accounting changes while still under CGAAP in 2012 as permitted in the Ontario Energy Board (OEB) letter dated July 17, 2012. OHL determined that some asset components identified by Kinectrics were materially insignificant and would not be recognized as separate asset components under CGAAP. OHL transitioned to IFRS as of January 1, 2015.

POLICY

OHL's asset management policies are to replace immaterial and insignificant components at the same time as the significant component. All general plant assets, from accounts 1905 to 1980, will continue to be separately identified assets.

All distribution assets taken out of service before the end of its useful life, an estimated amount will be disposed of based on the decade of its original acquisition date as identified by the BDO Canada LLP analysis of assets completed December 31, 2011.

OHL complies with the "half year" rule, in which six months of depreciation is recorded in the asset's first year of service, and six months of depreciation is recorded in the year of disposition.

IFRS is more explicit in requiring the depreciation method used to reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. Each part of an asset with a cost that is significant in relation to the total cost of the item must be depreciated separately, which means the initial cost must be allocated between the significant parts. The IFRS standard allows parts identified that have the same useful lives and depreciation method to be grouped for depreciation purposes.

The depreciation method adopted by Orangeville Hydro must reflect the pattern in which the asset's future economic benefits are expected to be consumed by the entity. The decisions taken by management should be decided on an asset per asset basis.

Depreciation of cost less residual value is charged on a straight-line basis over the estimated useful lives of items of each depreciable component of PP&E. This should be used where assets are used to deliver a constant level of service to customers over time.

IFRS states that estimates of useful life must be reviewed at least at each annual reporting date. Any changes are accounted for prospectively as changes in estimates.

The following factors should be considered in determining the useful life of an asset:

a) Expected usage of the asset. Usage is assessed by reference to the asset's expected capacity or physical output.
b) Expected physical wear and tear, which depends on operational factors such as the number of shifts for which the asset is to be used and the repair and maintenance programme, and the care and maintenance of the asset while idle.
c) Technical or commercial obsolescence arising from changes or improvements in production, or from a change in the market demand for the product or service output of the asset.
d) Legal or similar limits on the use of the asset, such as the expiry dates of related leases.

The useful life of an asset is defined in terms of the asset's expected utility to the entity. The asset management policy of the entity may involve the disposal of assets after a specified time or after consumption of a specified proportion of the future economic benefits embodied in the asset. Therefore, the useful life of an asset may be shorter than its economic life. The estimation of the useful life of the asset is a matter of judgement based on the experience of the entity with similar assets.

The analysis performed on the PPE components including poles, transformers, conductor and conduit includes suggested revised useful lives as stated in the OEB depreciation study report. The study suggests the minimum, maximum and typical useful life for the components. When performing the analysis of component costing, the typical useful life was used. Management may revise the useful life of the components if conditions specific to the utility suggest an alternate depreciation period.

A disposal occurs when an item of PP&E or intangible asset is no longer used by the Company. A disposal can be due to a sale to a third party, the expiration of the useful life of an asset or retirement of asset. After an asset disposal occurs the Company no longer has use of the asset.

Under the straight-line depreciation method, when assets are disposed of, the gain or loss is realized in net income and the original cost and accumulated depreciation are adjusted to zero. This applies to dispositions at any point in the life of the asset as well as dispositions at the end of the life of the asset. The gain or loss on the disposal of PP&E or intangible assets are determined as the difference between the net disposal proceeds and the carrying value at the date of disposal.

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Table 1: Capital Asset Useful Lives

Asset Class ID	Class Description	Useful Life
16110-01	Computer Software (prev. 1925)	5
16110-02	Smart Meter Computer Software	5
16120-01	Land Rights (prev. 1806)	0
18001-01	Land - MS#1 - 40 Mill St	0
18002-01	Land - MS#2 - Centennial Road	0
18003-01	Land - MS#3 - Dawson Road	0
18004-01	Land - MS#4 - ODSS High school	0
18005-01	Land - MS#5 - 3rd St/5th Ave	0
18060-01	Land Rights-Easements	25
18080-01	Buildings & Fixture-Dist Plant	50
18200-01	Dist Stn-Power Transformers	45
18200-02	Dist Stn-Metal Clad Switchgear	40
18200-03	Dist Stn-Station Switch	50
18200-04	Dist Stn-Steel Structure	50
18200-05	Dist Stn-Civil,Fencing,Gravel	30
18200-06	Dist Stn-Other Components	30
18210-01	Wholesale Meters	15
18300-01	Poles - Wood	45
18300-02	Poles - Concrete	60
18350-01	OH Conductors & Devices	60
18350-02	OH Conductors-Line Switch	45
18400-01	UG Conduit-Ducts	50
18400-02	UG Conduit-Concrete Duct Banks	55
18400-03	UG Conduit-Foundation for S/G	55

Asset Class ID	Class Description	Useful Life
18450-01	UG Conductor-Pri Direct Buried	30
18450-02	UG Conductor-Primary in Duct	40
18450-03	UG Conductor-Padmount Swtchger	30
18450-04	UG -Foundation for Switchgear	55
18450-S	PME's & KBAR's	30
18500-S	Transformer Spares	40
18505-01	OH Transformers	40
18510-01	UG Transformers-Pad Mounted	40
18510-02	UG Transformers-Foundations	55
18550-01	Services-Secondary Direct Buri	35
18550-02	Services-Secondary in Duct	40
18550-03	Services-OH Secondary Conductr	60
18605-01	Stranded Meters	25
18610-01	Smart Meters-Res and GS<50	15
18610-02	Smart Meters - TGB	15
18610-03	Smart Meters - MDM/R	15
18610-S	Smart Meter Stock	15
18615-01	Commercial Meters-GS>50	25
18615-S	GS >50kW Stock	25
18620-01	CTs and PTs	50
18620-S	CT/PT Spares	0
19000-01	Land-General Plant	0
19060-01	Land Rights - General Plant	25
19080-01	Building - Structure	60

Asset Class ID	Class Description	Useful Life
19080-02	Building - Roof	20
19080-03	Building - HVAC	30
19080-04	Building - Driveway	25
19080-05	Building - Renovations	20
19150-01	Office Furniture & Equipment	10
19200-01	Computer Equipment, Hardware	5
19200-02	Smart Meter Computer Hardware	5
19250-01	Computer Software	5
19250-02	Smart Meter Computer Software	5
19320-01	Transport Equip. Under 3 Tons	8
19320-02	Management Trucks	8
19330-01	Transport Equip. Over 3 Tons	12
19340-01	Transport Equip Work & Service	15
19350-01	Stores Equipment	10
19400-01	Miscellaneous Tools & Equipmen	10
19450-01	Measurement & Testing Equip	10
19550-01	Communication Equip-Towers	60
19550-02	Communication Equip-Wireless	10
19600-01	Miscellaneous Equipment	10
19600-02	Smart Meter Misc Equipment	10
19700-01	Load Management Controls	10
19800-01	System Supervisory Equipment	20
20750-01	Solar Generation	25
24400-1612-01	DefRev Land Rights	0

Asset Class ID	Class Description	Useful Life
24400-18300-01	DefRev Wood Poles	45
24400-18300-02	DefRev Concrete Poles	60
24400-18350-01	DefRev OH Conductors	60
24400-18350-02	DefRev OH Line Switch	45
24400-18400-01	DefRev UG Conduit Ducts	50
24400-18400-02	DefRev UG Conduit-Conc Duct Ba	55
24400-18450-01	DefRev UG Conductor Pri Buried	30
24400-18450-02	DefRev UG Primary CablesinDuct	40
24400-18450-03	DefRev UG Padmount Switchgear	30
24400-18450-04	DefRev UG found for SWG	55
24400-18505-01	DefRev OH Transformers	40
24400-18510-01	DefRev UG Padmount Transformer	40
24400-18510-02	DefRev UG Transf-Foundations	55
24400-18550-01	DefRev Serv-Sec Direct Buried	35
24400-18550-02	DefRev SVC Sec Cables Duct	40
24400-18550-03	DefRev OH Sec Conductor	60
24400-18610-01	DefRev Res and GS<50 Meters	15
24400-18615-01	DefRev Commercial Meters	25
24400-18620-01	DefRev CTs and PTs	50
24400-19400-01	DefRev-Tools, Shop and Garage	10

Orangeville Hydro Policy and Procedures			
Topic	**Depreciation Policy**	Number	FN-007
Category	Finance	Revision Number	2
Revised by	Suzanne Presseault, Senior Accountant	Issued and Effective	October 24, 2013
Reviewed by	Amy Long, CFO	Revision Issued and Effective	September 21, 2023
Approved by	Rob Koekkoek, President		

APPENDIX 2-C DISTRIBUTION SYSTEM PLAN

Orangeville Hydro Limited

Distribution System Plan

2024 Cost of Service Application

Historical Period:

2018 – 2023 (2023 Bridge Year)

Forecast Period:

2024 – 2028

September 2023

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LIST OF ACRONYMS

Acronym	Meaning
ACA	Asset Condition Assessment
AM	Asset Management
AMI	Advanced Metering Infrastructure
CDM	Conservation Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
DER	Distributed Energy Resources
DSP	Distribution System Plan
EDA	Electricity Distributors Association
ESA	Electrical Safety Authority
GIS	Geographic Information Systems
GS	General Service
HI	Health Index
IESO	Independent Electricity System Operator
LOS	Loss of Supply
MED	Major Event Detail
ODS	Operations Data Storage
OEA	Ontario Energy Association
OEB	Ontario Energy Board
OH	Overhead
REG	Renewable Energy Generation
RRFE	Renewed Regulatory Framework for Electricity Distributors
RRR	Reporting and Record-keeping Requirements
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
UG	Underground

5.2 DISTRIBUTION SYSTEM PLAN

Orangeville Hydro Limited ("OHL") has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB") Chapter 5 – Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, dated December 15, 2022 (the "Filing Requirements") as part of its 2024 Cost of Service Application (the Application).

The DSP is a stand-alone document that is filed in support of OHL's Application. The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. The DSP covers the historical period of 2018 to 2022, with 2023 being the bridge year, and a forecast period of 2024 to 2028, with 2024 being the Test Year.

The DSP contents are organized into three major sections:

- Section 5.2 provides a high-level overview of the DSP, including coordinated planning with third parties and performance measurement for continuous improvement.
- Section 5.3 provides an overview of asset management practices, including an overview of the assets managed and asset lifecycle optimization policies and practices.
- Section 5.4 provides a summary of the capital expenditure plan, including a variance analysis of historical expenditures, an analysis of forecast expenditures, and justification of material projects above the materiality threshold.

The materiality threshold for OHL is $10,000, and detailed descriptions of specific projects/programs exceeding the materiality threshold are provided in Section 5.4.2.1 and Appendix E. Other pertinent information relevant to this DSP is included in the Appendices.

This DSP follows the chapter and section headings in accordance with the Chapter 5 Filing Requirements.

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

5.2.1.1 Description of the Utility Company

OHL is an electricity distributor licensed by the OEB. In accordance with its Distribution License ED-2002-0500, OHL provides electricity distribution services in the Town of Orangeville and the Town of Grand Valley, serving a population of approximately 34,000.

OHL is incorporated under the Ontario Business Corporations Act and is a member of Utility Collaborative Services Inc ("UCS"), Cornerstone Hydro Electric Concepts ("CHEC"), Utility Standards Forum ("USF"), and Electricity Distributors Association ("EDA"). OHL is owned by the Town of Orangeville and the Town of Grand Valley, with ownership interests of 94.5% and 5.5% respectively.

OHL receives power from Hydro One Networks Inc. ("HONI") and delivers electricity to its customers. OHL is responsible for maintaining distribution and infrastructure assets deployed over 17 square kilometers (including over 222 kilometers of overhead and underground lines) within the Orangeville and Grand Valley service areas.

Mission: To provide safe, reliable, efficient delivery of electrical energy while being accountable to our shareholders...the citizens of Orangeville and Grand Valley.

While we must operate as a business and be profitable for our shareholders, our main reason for existing is to provide safe, reliable, and economic electricity services to the people of the Town of Orangeville and the Town of Grand Valley. That is what distinguishes us from other large, remotely owned, and controlled energy companies.

Vision: To be acknowledged as a leader among electrical utilities in the areas of safety, reliability, customer service, sustainability, and financial performance.

Core Values: To continue as a profitable electricity distribution enterprise the following principles are core values of our Company:

- We value professionalism and safety in our service and our work.
- We value people - our customers, employees, board members, and shareholders.
- We value our community - its environment and its economic progress.
- We value integrity, honesty, respect, and communications.
- We value local control, local accountability, local employment, and local purchasing; and
- We value easy accessibility for our customers.

Corporate Strategic Goals:

OHL's latest Business Plan (2023) confirms the strategic goals of the corporation as follows:

- **Safety:**
    - Provide safe work practices for all employees consistent with industry best practices.
    - Communicate and promote a safety culture to stakeholders.
- **Customer Focus:**
    - Leverage technology to enhance the customer experience and increase operational agility.
    - Engage customers at an individual level through existing social media platforms and mobile technology.
- **Operational Effectiveness:**
    - Share best practices with other utilities and stakeholders.
    - Better utilize resources.
    - Properly maintain infrastructure.
    - Inform, engage, support, and motivate staff to assist in accomplishing corporate goals.
- **Public Policy Responsiveness:**
    - Capable of accommodating Distributed Energy Resources and electric vehicle technology.
    - Successfully deliver Provincial Programs to customers.

  - Deliver obligations mandated by pertinent government legislation and regulatory requirements.
  - Investigate how to leverage non-regulated business activities.
- **Financial Performance:**
  - Maximize financial viability.
  - Maintain just and reasonable rates.
  - Meet and/or exceed industry benchmarks.
  - Investigate feasible opportunities to grow the distribution business and potential affiliate business opportunities.

5.2.1.2 Capital Investment Highlights

OHL's capital investments over the planning period have been aligned to the 4 categories of system access, system renewal, system service, and general plant outlined in the Filing Requirements. Table 5.2-1 presents OHL's historical actuals and forecast expenditures for both capital and O&M categories. OHL's 2023 expenditures are projected actuals for projects on track for completion in 2023, however, values are not final and may still change upon year completion.

Table 5.2-1: Historical and Forecast Capital Expenditures and System O&M ($ '000)[1]

Category	Historical					Bridge	Forecast				
	$ '000					$ '000	$ '000				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System Access (Gross)	510	303	373	737	96	820	1,360	659	689	650	866
System Renewal (Gross)	202	218	395	530	554	583	787	721	817	738	807
System Service (Gross)	626	677	877	925	2,198	977	819	1,194	1,405	1,359	1,557
General Plant (Gross)	444	171	281	66	135	124	711	436	215	490	225
Gross Capital Expenses	1,781	1,368	1,925	2,258	2,983	2,505	3,677	3,010	3,126	3,237	3,455
Contributed Capital	(199)	(115)	(240)	(349)	(63)	(451)	(719)	(204)	(378)	(292)	(373)
Net Capital Expenses after Contributions	1,582	1,253	1,685	1,909	2,920	2,053	2,958	2,806	2,748	2,945	3,083
System O&M	755	959	807	1,078	1,164	1,249	1,359	1,393	1,379	1,170	1,199

OHL considers performance-related asset information including, but not limited to, data on reliability, asset age and condition, loading, customer connection requirements, and system configuration, to determine investment needs of the distribution system. OHL's DSP demonstrates prudence and rate mitigation consideration in the pacing and prioritizing of non-discretionary investments, specifically those related to replacement or renewing end-of-life assets.

It can be expected that the operational and service requirements driving OHL's capital expenditures, and found within its DSP, should generally remain consistent through the 2024 to 2028 forecast period. The projected expenditures for 2024 and going forward reflect:

- the typical spending needs of a distribution electric utility serving a stable customer base with a geographically distributed (over two separate service areas), and a diverse collection of physical assets.
- focused planned capital sustainment investments required to replace the deteriorated assets found in OHL's distribution system.

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

[1] These numbers are rounded. There may be some inconsistencies observed due to rounding errors.

were considered in the analysis of capital investment options and are further described in Section 5.4 of the DSP.

There are several ongoing and proposed projects that OHL may consider undertaking to address grid modernization, DERs integration and climate change adaptation. The following activities are being considered or undertaken at OHL:

Storm Hardening – Employing proven storm hardening techniques such as installing stainless steel equipment for at-grade applications, moving below grade equipment to above grade (if possible) where flooding is a possibility, design to Canadian Standard Association ("CSA") Heavy Loading conditions standards, and utilize stronger poles in construction. New subdivisions were designed with underground distribution.

Voltage Conversion – Upgrading the 4.16 kV system to 27.6 kV to increase load transfer capability, increase capacity, reduce losses, and allow higher penetration of distributed energy resources ("DER").

Replacement of obsolete assets – Grid modernization effort to remove assets that no longer meet OHL's design standards. Removing these assets will support reliability performance, resiliency, and operational efficiency while reducing OHL's procurement and spare inventory costs through the standardization of equipment.

Station Decommissioning – OHL is planning towards being a station-less grid, meaning all stations and associated equipment will not be owned and managed by OHL. This will reduce operations and maintenance costs on station assets. Additionally, the removal of stations may reduce the number of feeders as well which can introduce cost savings and long-term benefits with regards to streamlined data lifecycles.

There are also a few ongoing and future activities in the OHL service areas that may impact the capital project prioritization and spending as outlined in the DSP.

Customer Connections

Customer connection forecasts are based on timing information received from planning staff, planning reports (provincial, regional, municipal), developer submissions and inquiries, and historical connection rates. Variances in connection timing/quantity over the DSP period will impact actual connections and related System Access expenses.

Municipal Road Projects

The Towns of Orangeville and Grand Valley carry out road reconstruction and other types of roadway improvements on an annual basis. Timing and location for these works are subject to short-term planning considerations, and as such, are frequently rescheduled. OHL will be required to accommodate and react to these road projects as they occur during the period of the DSP.

5.2.1.2.1 System Access

These investments are modifications (including asset relocation) to the distribution system that OHL is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via OHL's distribution system. These investments are considered mandatory and non-discretionary.

OHL will continue to provide access to its system for both residential and commercial; new and upgraded services. OHL does not expect significant electrification of transportation or building will factor into the forecast period. In addition, OHL has incorporated feedback from third parties regarding the potential relocations of OHL plant due to roadway improvements. The forecasted system access plan will result in an increase of planned expenditures compared to the historical period.

5.2.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety, and sustainment of the distribution system. OHL's ACA recommends assets for renewal based on condition data from tests and inspections.

OHL focuses on replacing wooden poles, transformers and hardware which exhibit signs of deterioration consistent with EOL criteria as defined by the utility's asset management standards. For the forecast period, OHL's investment fall under four programs:

- Hardware Replacement
- Pole Replacement
- Failed Transformer/PME replacement
- Meter replacement/additions

5.2.1.2.3 System Service

Expenditures in this category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements (i.e., station capacity increases, feeder extension, etc.). OHL's forecast plan focusses on completing its voltage conversion program, enabling it to become a station-less utility, improving its reliability and flexibility within its network.

5.2.1.2.4 General Plant

Expenditures in this category are driven by the need to modify, replace or add to assets that are not part of the distribution system but support the utility's everyday 24/7 operations. OHL's key projects and programs over the forecast period include:

- A roof replacement of OHL's main office - OHL's building was built in 1990 and the roof is beyond its life expectancy. OHL was informed by a third party that it is in serious need of replacement.
- Upgrade of software to an industry standard for "Geographic Information Systems" (GIS).
- A financial software upgrade and an enhanced customer portal. OHL's existing customer portal is no longer being supported and is increasing cybersecurity concerns.

5.2.1.3 Key Changes since Last DSP Filing

This is the third DSP filed by OHL. Minimal changes were made to OHL's processes to minimize the capital, maintenance, and administration costs to OHL and its customers. OHL has only invested in and introduced new processes if needed to improve service and quality to its customers as well as maximize efficiencies. These include updated inspection and maintenance programs with improved data collection practices on asset inspections to utilize the appropriate capital investment dollars.

Furthermore, this DSP reflects a continuous improvement in the application of asset management principles by OHL. The DSP intends to guide OHL in enhancing and refining its asset management process to achieve the set goals within the forecast period. Furthermore, the DSP is OHL's 5-year roadmap which includes system developments and improvements for the benefit of its customers and stakeholders. The asset management process will be continually improved and implemented over the forecast period by adding additional asset data and analytics to OHL's future asset and program planning.

It should be also noted that there are other factors that are challenging and affecting both OHL and its customers. These include the current economic factors of low unemployment meaning a labour shortage, continued supply chain shortages for key items, such as transformers and accessories, high inflation, higher borrowing cost, housing crises, alongside the continued increased focus on the impacts of climate change. OHL has tried to factor as many of these issues within its plan, however with the potential level of uncertainty, OHL's plans may need to be adapted and updated, using its planning process, throughout the forecast period. The current plan has been developed with the best available information at the time.

5.2.1.4 DSP Objectives

OHL's DSP is a stand-alone document and is filed in support of OHL's Application. The DSP is designed to present OHL's fully integrated approach to capital expenditure planning. This includes comprehensive documentation of its Asset Management ("AM") process that supports its future five-year capital expenditure plan while assessing the performance of its historical five-year period. It recognizes OHL's responsibilities and commitments to provide customers with reliable service by ensuring that its asset management activities focus on customer preferences, operational effectiveness, public policy responsiveness and financial performance.

OHL's Distribution System Plan is designed to support the achievement of the four key OEB established performance outcomes:

1. **Customer Focus:** services are provided in a manner that responds to identified customer preferences.
2. **Operational Effectiveness:** continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.
3. **Public Policy Responsiveness:** utilities deliver on obligations mandated by the government (e.g., in legislation and regulatory requirements imposed further to Ministerial directives to the Board).
4. **Financial Performance:** financial viability is maintained, and savings from operational effectiveness are sustainable.

To achieve a fully complete and compliant DSP, OHL was required to accomplish the following:

- Understand customer preferences – how do customers wish to receive service and how do they wish to interact with the utility to obtain the information they require and understand the goals, objectives, and priorities of the utility.
- Develop a plan for continuous improvement which includes concepts from reliability maintenance, asset monitoring and project prioritization.
- Understand the age, condition, and performance of its assets.
- Ensure its inspection practices are conducted following the Distribution System Code ("DSC").
- Describe its maintenance activities following good utility practice.
- Ensure that all aspects of employee and public safety are addressed in compliance with all regulatory and legal obligations.
- Forecast and plan for the growth of load customers and renewable generation facilities.
- Recognize and address constraints in the current distribution system and anticipate future capacity requirements.
- Review the historical years with the current year of capital expenditures and report on variances from the previous DSP.
- Demonstrate that the asset management process recognizes the above items and prioritizes projects to accommodate customers and system requirements.
- Develop a five-year forward-looking capital expenditure plan that anticipates the future growth, capacity and performance of the distribution system while remaining flexible to accommodate the unknown requirements of its customer base.

OHL's DSP documents its asset management processes and capital expenditure plan for the 2024-2028 period, which integrates qualitative and quantitative information resulting in an optimal investment plan that covers:

- Customer value considerations
- System expansion considerations
- System renewal considerations
- Regional planning considerations
- Renewable generation considerations
- Smart grid considerations
- Alignment with public policy objectives

OHL incorporates good utility practices of the electricity distribution industry into its operations. This includes adhering to the OEB's DSC that sets out both good utility practices, minimum performance standards for electricity distribution systems in Ontario, and minimum inspection requirements for distribution equipment. Consistent with good practices, OHL continues to maintain its equipment in safe and reliable working order and, only when economically justified, upgrades, or renews its equipment. However, to maintain a moderate increase in the customers' bills, OHL is prudent when incurring costs over the historical period. This is in direct response to customer satisfaction survey results which indicate that the low price of electricity is an important factor to customers.

5.2.2 Coordinated Planning with Third Parties

In preparing this DSP, OHL has considered the needs of its customers, subdivision developers, the municipal governments of Orangeville and Grand Valley, HONI, other LDCs and the IESO. This DSP considers the outcomes of completed consultations, reports, and plans as well as a continued effort in coordinating with any future ongoing developments with third parties. The following sections describe the infrastructure planning consultations that OHL participated in.

5.2.2.1 Customers

OHL's customer engagement activities related to this DSP took place from May 2021 to July 2021, through an online customer engagement. Many of the customer engagement findings corroborated what OHL had been hearing recently from customers, via the ongoing dialogue through the day-to-day engagement. Key learnings that emerged through the engagement included:

- One of the top feedback items received from customers was to keep rates low. OHL understands that high bills can be challenging for its customers, including over the years during the COVID-19 pandemic. To address this, OHL believes it budgets its capital plans efficiently and with care, keeping in mind the financial impact it can have on its customers.
- The second most important choice selected by customers was the safety for employees and the public. This is in alignment with OHL's core objectives and is measured annually through a set of metrics.
- Customers believe OHL should begin investing in infrastructure that accommodates new technologies sooner than later. However, the majority (65%) of customers believe it should be at no additional cost to the customer and only a few participants (approximately 17%) are willing to pay a little more.

Although the participation rate was low relative to the total number of customers served by the utility at just over 3%, OHL believes the pattern of responses from this sample of participating customers would not change dramatically. Hence, it is safe to assume that this engagement process garnered sufficient qualitative feedback to indicate customer preferences.

The purpose of OHL engaging with its customers is to incorporate customer's issues and needs within the utility's capital and maintenance plans while also communicating with customers of ongoing efforts to meet the expected level of service. OHL is both proactive and reactive in its customer engagement consultations and engages its customers through multiple ongoing streams which include:

- In-person engagements at OHL's offices.
- Social media platforms to bring attention to ongoing outages, restoration efforts, and other topics of interest.
- Phone calls through customer service can assist customers in addressing their needs and issues.
- Email sign-ups for receiving paperless bills and notices.
- Customer portal for looking up their power consumption habits and identifying ways to reduce costs.

- Website communication of important updates happening at OHL.
- One-on-one meetings with large business/industrial customers.
- Group meetings with large business/industrial customers.
- Attendance at community events and customer appreciation events

Discussions through the consultations provide helpful insight into the day-to-day operations at OHL. Consultations with industrial customers are conducted periodically primarily to engage and promote participation in utility offered programs, such as CDM initiatives in the past. In addition to this, OHL capitalizes on the opportunity to discuss power quality, other reliability issues, and future system planning.

In 2021, OHL proceeded to complete its DSP customer engagement for both residential and business customers. The purpose of this engagement was to consolidate and consider the feedback received on OHL's upcoming DSP filing and its proposed investment plan. OHL sought direct input from customers to determine if OHL's operational and capital plans aligned with customer preferences and whether customers would ultimately support OHL's decision-making in providing the best, optimized and effective plan for its customers. In summary, customer consultations support the DSP's focus on maintaining existing reliability and service levels through prioritized, efficient, and paced investments while managing the level of bill impacts.

OHL regularly seeks customer feedback to help shape the direction and development of the community investment. OHL prioritizes efforts to connect with customers to ensure that their expectations are being met and to implement suggestions on how OHL can improve their overall customer experience. For OHL to achieve its goals and efforts, OHL undertakes several ongoing customer engagement activities daily, including:

I. Direct Engagement
    - Telephone calls, emails, written letters, and notices
    - Bill inserts
    - In-person interactions at offices
    - Local community events

II. Online Engagement
    - Corporate website
    - Online bill portal for residential and commercial customers
    - Online outage map
    - Social Media (Twitter, Facebook)

III. Customer Survey Program
    - Customer Satisfaction surveys
    - Public Safety Awareness surveys
    - Customer feedback survey

OHL engaged its customers in 2021 through an online survey to gather feedback. Supplementary material was developed by OHL and was communicated to its customers for them to have adequate information to respond to each question. The survey covered various topics such as customer costs, reliability issues and future investments. OHL opened the survey to every resident and customer serviced by OHL which ensured that everyone who wanted to have a say could participate, while also making sure OHL heard from all types of customers.

In 2021, Orangeville Hydro utilized *Bang The Table Engagement HQ* software as the platform for customer engagement. The platform, known as *Engage Orangeville Hydro*, featured interactive tools such as a survey platform, news feed, and forums. The primary objective for utilizing the survey platform was to gather customers' opinions, preferences, and insight on how OHL should prioritize their investments relating to the DSP.

The *Customer Engagement Survey* took place between April 2021 to June 2021, during which 6 commercial and 386 residential account holders completed the survey, for a total of 392 responses. Participants completed 12 questions relating to demographics, power outages and reliability, grid modernization, system renewal, and investments priorities and trade-offs relating to the DSP. Due to the response size of commercial accounts, the data will be grouped to reflect a sample size of all Grand Valley and Orangeville accounts. The information collected was used to determine the next steps in OHL's Distribution System plan for both the 2022-2026 years and 2024-2028 years. The results of the survey are found in Appendix D.

At the beginning of the survey, customers were asked to determine what is most important to them: a reliable supply of electricity or low-cost electricity service. The overarching theme in the data proved that customers believe a low-cost electricity service is most important to them. The data collected highlights that customers value a reliable supply of electricity, minimal power outages, and grid modernization, but not at the expense of increased rates.

OHL's first customer engagement process findings are in alignment with OHL's goals and expectations for its customers. Of the few key learnings that emerged from OHL's customer engagements, the following pertained to OHL's planning procedures for its current DSP:

I. The most important choice selected by customers was to maintain the affordable cost of electricity (i.e., keep rates low). OHL understands that high bills can be challenging for its customers, including over the recent pandemic. To address this, OHL believes it budgets its capital plans efficiently and with care keeping in mind the financial impact it can have on its customers.
II. The second most important choice selected by customers was the safety for employees and the public. This is in alignment with OHL's core objectives and is measured annually through a set of metrics.
III. Customers believe OHL should begin investing in infrastructure that accommodates new technologies sooner than later. However, the majority (65%) of customers believe it should be at no additional cost to the customer and only a few participants (approximately 17%) willing to pay a little more.

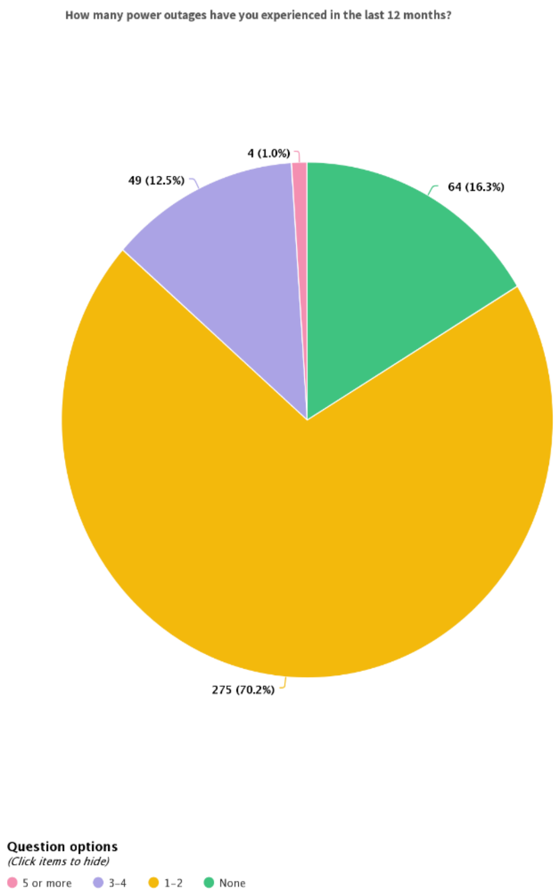
Although the response rate was low relative to the total number of customers OHL serves, the pattern of responses from this sample of participants indicates that this engagement process should have garnered sufficient qualitative feedback to indicate customer preferences. Customer preferences resulted in no major changes to the proposed budget or priority of projects for the DSP period as the preferences are in alignment with OHL's objectives.

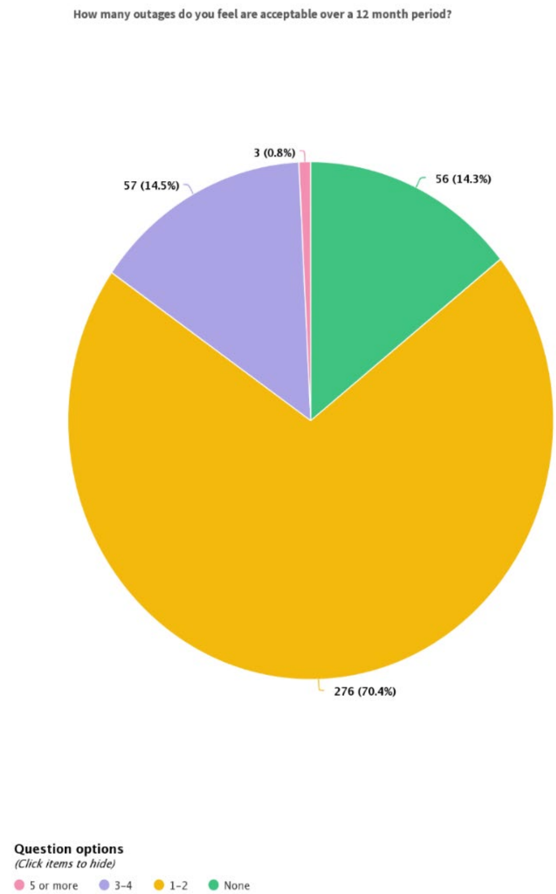
Some highlights from the customer survey are shown below.

Power Outages and Reliability

Customers were asked to reflect on how many power outages they believed they had in the last 12 months. 87% of customers believed they had 0-2 outages in 12 months, and 13% believed they had experienced 3-5 or more outages (Figure 1). Customers were then asked how many outages are acceptable in 12 months, 85% of customers believe 0-2 outages are acceptable and 15% believe 3-5 or more outages are acceptable (Figure 2). Based on the response it can be concluded that the utility is meeting current customers' needs in relation to the frequency of outages.

Figure 5.2-1: Survey Results for Power Outages and Reliability



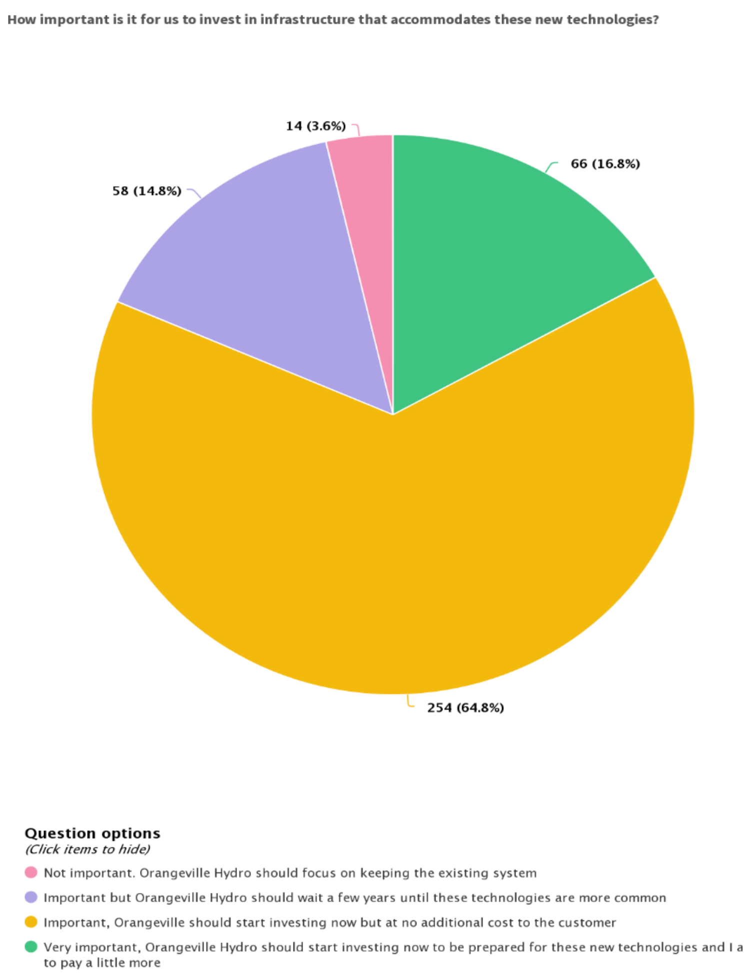


Grid Modernization

This section of the survey focused on the need for Local Distribution Companies ("LDC") to adapt and update their current grid to adhere to customers' expectations for advancing technologies. This section sought to highlight the topic of grid modernization and educated customers on the advancements of the electricity industry such as electric vehicles, renewable energy generation, and battery backup power supply. Participants were asked, *"How important is it for (Orangeville Hydro) to invest in infrastructure that accommodates new technology?"*

A large portion of customers (80%) agreed that while it is important to invest in the infrastructure, OHL should wait for these technologies to evolve or should begin to invest now but not at the expense of increased rates. Whereas a select group of customers (17%) believe that accommodating these new technologies is very important and OHL should begin to invest now, even if rates increase slightly.

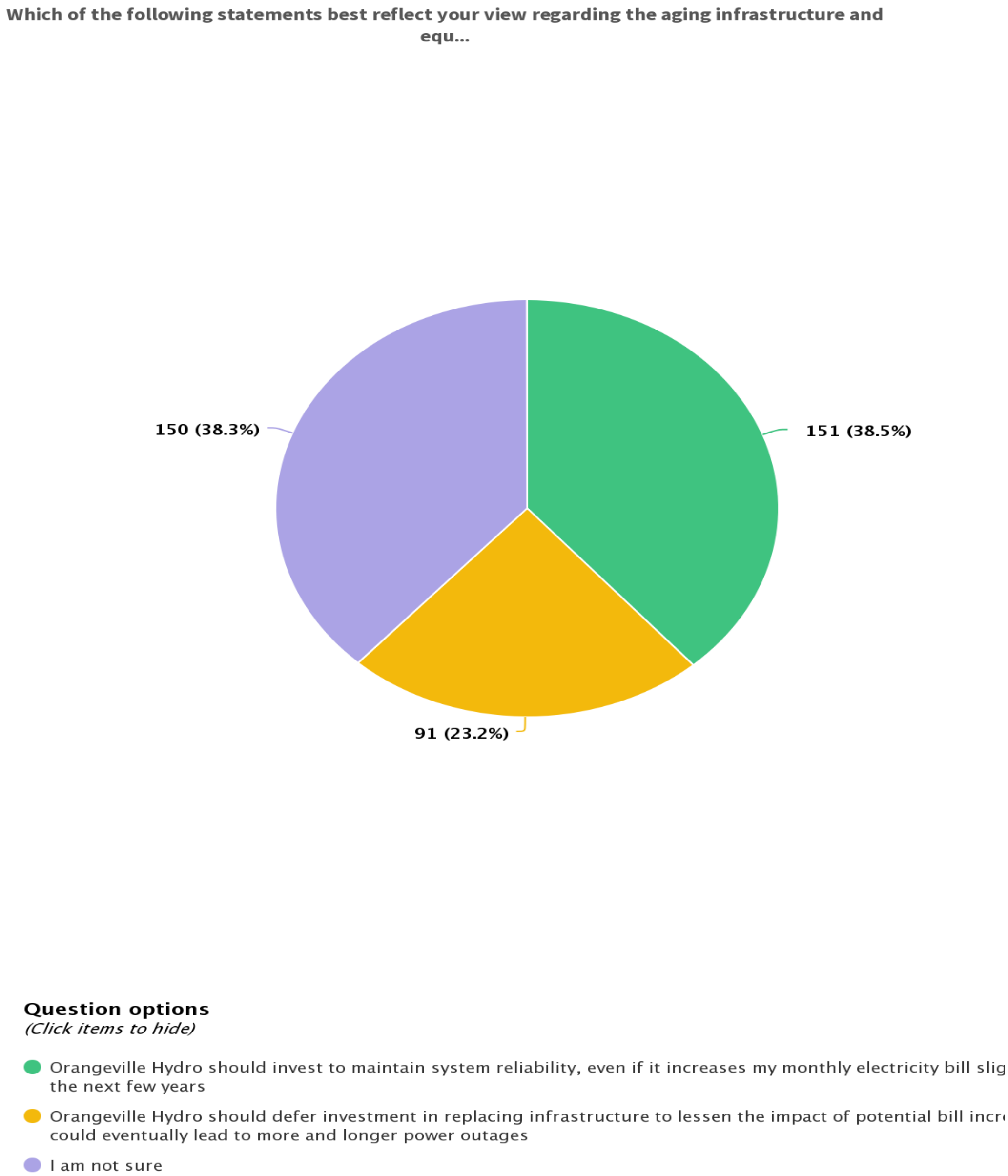
Figure 5.2-2: Survey Results for Grid Modernization



System Renewal

Customers were asked to pick a statement that reflects their view regarding investments in ageing infrastructure and equipment. 23% of customers stated that OHL should defer investing in infrastructure and ageing equipment even if it could eventually lead to more and longer power outages. 39% of customers stated that the utility should begin to invest even if their monthly bill increases slightly, although, 38% of customers answered that they were not sure. As seen in the figure below, 151 responses were in favour of increased rates and 150 were not sure about investing in the infrastructure. However, earlier in the survey customers were asked to pick from three options to describe what is most important to them regarding rates and increasing reliability. Customers could choose from, (1) Maintaining OHL's current electricity rates, (2) Keeping distribution rates low even if reliability may decrease, (3) slightly higher distribution rates increasing system reliability. 93% of customers would like to see distribution rates remain low or stagnant, whereas only 7% of customers were in favour of slightly higher distribution rates. It can be concluded that the participants were not provided with enough context to give an educated answer regarding ageing infrastructure and equipment, but it is presumed based on the data that customers are not willing to lose electrical reliability nor pay more for distribution rates.

Figure 5.2-3: Survey Results for System Renewal



Distribution System Plan – Investment Priorities/Trade-Offs

This section of the survey focused on customer preferences in relation to investment priorities, trade-offs and pacing of investments (see Figure below). Customers were asked to indicate on a scale of 1 to 5, 1 being important and 5 being not important at all, to indicate the level of priority. By indicating the level of priority, OHL can gather insight as to what customers expect from the utility in future years. Participants were asked about multiple areas including:

- Ensuring reliable electrical service
- Delivering electricity at reasonable distribution rates

- Investing in new technologies that could help reduce future electricity distribution costs.
- Replacing ageing infrastructure that is beyond its useful life.
- Upgrading the electrical system to better respond to and withstand the impact of adverse weather.
- Providing quality customer service and enhanced communications
- Helping customers with conservation and cost-saving initiatives

Figure 5.2-4: Survey Results for DSP – Investment Priorities/Tradeoffs

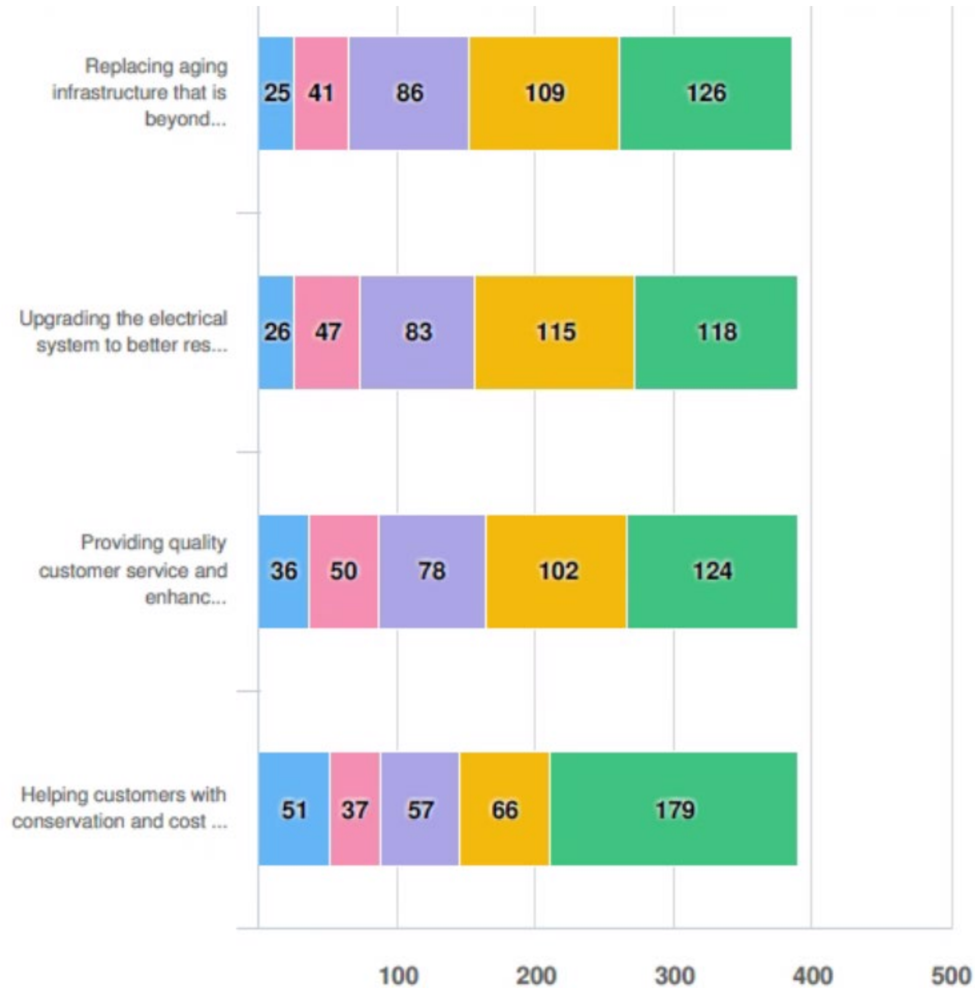
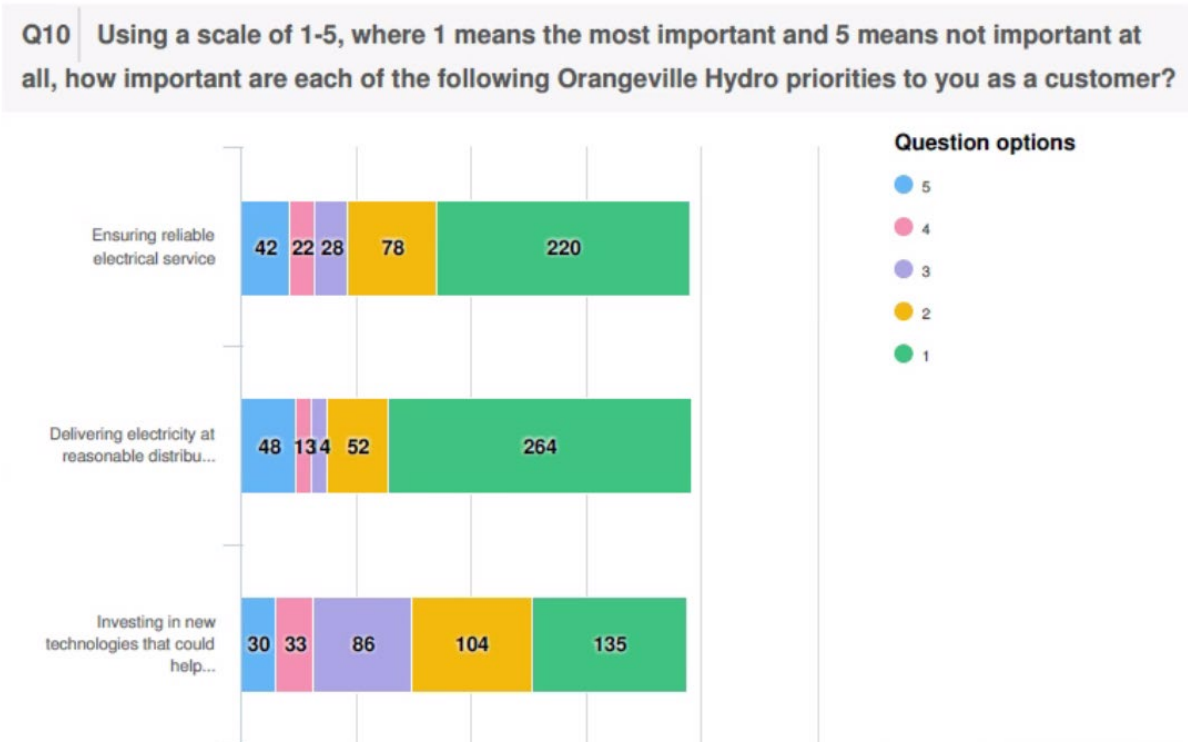


Figure 5.2-5: Survey Results for DSP – Investment Priorities/Tradeoffs



Based on the answers it is evident that customers do not expect OHL to focus on one priority, nor is any one priority significantly more important than another. While the data showed that the top two priorities for customers are to deliver electricity at reasonable distribution rates and ensuring reliable electrical service, it can be concluded that all areas identified are of high importance to the customers.

In direct response to customer preferences, OHL is not introducing additional projects or modifications to existing projects. Furthermore, at this time OHL has not included any costs for technology-based opportunities, innovative projects, or demonstrations in the forecast period to manage low customer bills through the DSP period aside from maintaining current systems used by customers today.

2023 Customer Satisfaction Survey

In addition to the above initiatives, OHL engaged with Advanis to conduct a *Customer Satisfaction Survey* in early 2023 and completed in March of that year. 407 surveys were completed, but representing 3.81% of OHL's customer base, with a margin of error of 4.8%. Though the sample was relatively small it is believed to be reflective of OHL's broader customer base. The survey reached a mixture of residential and commercial customers, who were asked questions relating to their expectations for electrical service, their familiarity with electrical distribution systems, the quality of different dimensions of OHL's service, and their sensitivity to potential changes in service. These responses were consolidated and analyzed to identify emerging trends, changes in attitudes over previous years, and benchmark OHL's performance against other peer LDCs.

Several themes emerged from the 2023 Customer Satisfaction Survey. Residential and commercial customers alike are generally satisfied with their service but are very sensitive to any potential increases in their bill or changes in the quality of their service.

- When asked how they would like investments in system infrastructure to affect their bill, 54% said they would prefer the same bill with about the same number and length of outages.
  - 7% would prefer a higher bill with fewer/shorter outages.
  - 18% would prefer a lower bill with more/longer outages.
  - The remaining 21% didn't know or had no opinion.
- When asked how they would like investments in equipment and IT infrastructure to affect their bill, 50% would prefer the same bill with about the same number and length of outages.
  - 7% would prefer a higher bill with fewer/shorter outages.
  - 18% would prefer a lower bill with more/longer outages.
  - The remaining 25% didn't know or had no opinion.

Customers were asked 4 questions on how important certain characteristics of our service are to them. They were asked to rate the importance from 0 (not important at all) to 10 (meaning very important). About 71% indicated that reliable power is highly important. That is, they answered 9 or 10 on a scale of 0 to 10. A somewhat lower percentage of 67% said that reasonable prices are highly important. Dependable and responsive customer service was rated as highly important by 51% of customers and lastly only 23% think it's highly important to receive education about energy conservation programs, this number is statistically lower than 2 years ago.

Customers were generally willing to adopt and utilize digital forms of communication (text messages, email) with OHL, such as receiving bills or outage information, especially when provided with incentives to switch, such as a one-time reduction in their bill.

5.2.2.2 Subdivision Developers

OHL maintains strong, active relationships with several subdivision developers in order to accommodate the connectivity needs of their projects. OHL regularly monitors the Grand Valley and Orangeville planning portals for activity and engages with all developers to connect new subdivisions. Currently, OHL is liaising with five developers, of which three are to connect in 2024. This has led to OHL allocating capital expenditures for the connection of subdivisions to the network from 2024 onwards. OHL will continue to monitor and engage with developers to understand their plans and adjust OHL's capital investment plans accordingly. OHL is also an active member of the Greater Dufferin Home Builders Association.

5.2.2.3 Municipalities

OHL maintains a relationship with both the Orangeville and Grand Valley municipal planning, engineering, and administrative teams. OHL consults regularly with the municipal departments to ensure it is informed and provided the opportunity to comment on all major infrastructure projects during the early design stage. The detailed engagement on municipal infrastructure projects occurs with municipal staff and their engineering consultant. In addition to major infrastructure projects, OHL can comment on all severances and variances through the committee of adjustment process. This process is ongoing, and the results of these consultations inform OHL's knowledge of developments, severances, and variances within the Town of Orangeville and the Town of Grand Valley. The committee of adjustment process also provides the opportunity for OHL to inform the municipality of potential issues such as clearance issues between electrical infrastructure and future buildings.

OHL discusses with the planning teams the implications of developments to the distribution system in terms of potential system renewal, system access and system service projects. OHL work with the municipal planning teams to achieve their goals such as road reconstruction, new municipal buildings, the installation of public electric vehicle chargers, and the electrification of the municipal transit and municipal fleet. Respective projects that impact OHL's distribution system are categorized in the appropriate investment categories as they are detailed or requested by Orangeville and Grand Valley. OHL works closely with Orangeville and Grand Valley in the execution of capital projects and in assisting them through the prioritization of projects. Direction provided by the OHL Board of Directors, Town Official Plan, Dufferin County, and private developers is taken into consideration as well.

The consultations with the municipalities have assisted with OHLs timing of proposed voltage conversion projects, such as OHL joining the reconstruction project on Ontario Street and Vicotria Street in Orangeville in 2024. OHL is attempting to align the installation of OHL's underground civil infrastructure with the municipal road reconstruction projects. Regarding the municipalities new build and electrification plans, if the municipalities move forward with their potential new connections or service upgrades, OHL's project costs, including capital contribution, would be contained within the forecasted amounts under the System Access program.

5.2.2.4 Transmitter

OHL is connected to the main Ontario power grid via a single Transmission Station ("TS") – Orangeville TS, owned and operated by HONI. OHL and HONI are in constant conversation regarding changes on their respective systems that would materially affect each utility.

As identified in the 2022 Regional Infrastructure Plan ("RIP") and in the April 2020 Needs Assessment report, HONI intends to replace and upgrade the existing Orangeville TS transformers and reconfigure low voltage equipment due to the asset being at the end of life from a condition standpoint. The upgrades are presently underway with the 44kV upgrades already completed in 2023 and the with an in-service date scheduled for 2024 for the 28kV upgrades. HONI and OHL have collaboratively worked throughout every step of this upgrade. Furthermore, Grand Valley is serviced from HONI's existing 3MVA transformer as Grand Valley Distribution Station ("DS"). HONI's present plan is to refurbish the Grand Valley DS in 2025 and upgrade the existing transformer with a 5MVA transformer. Other existing equipment may be replaced as well depending on age and condition, however, current information in these plans is limited. OHL and HONI's conversations which impacted this DSP, could evolve over the course of the present DSP.

5.2.2.5 Other LDCs

OHL engages with many other LDCs through a variety of forums. These interactions principally occur through voluntary participation in several collaborative organizations such as the EDA, USF, CHEC, and UCS. From these forums, OHL can share and learn about best practices, new standards and legislation, and adjust its investment plans as required. On an operational level, OHL works with other LDCs on an as-needed basis. As OHL is not an upstream or host distributor to any other utilities, there is no regular engagement from day to day. No interaction and consultations with other LDCs have directly affected OHL's DSP.

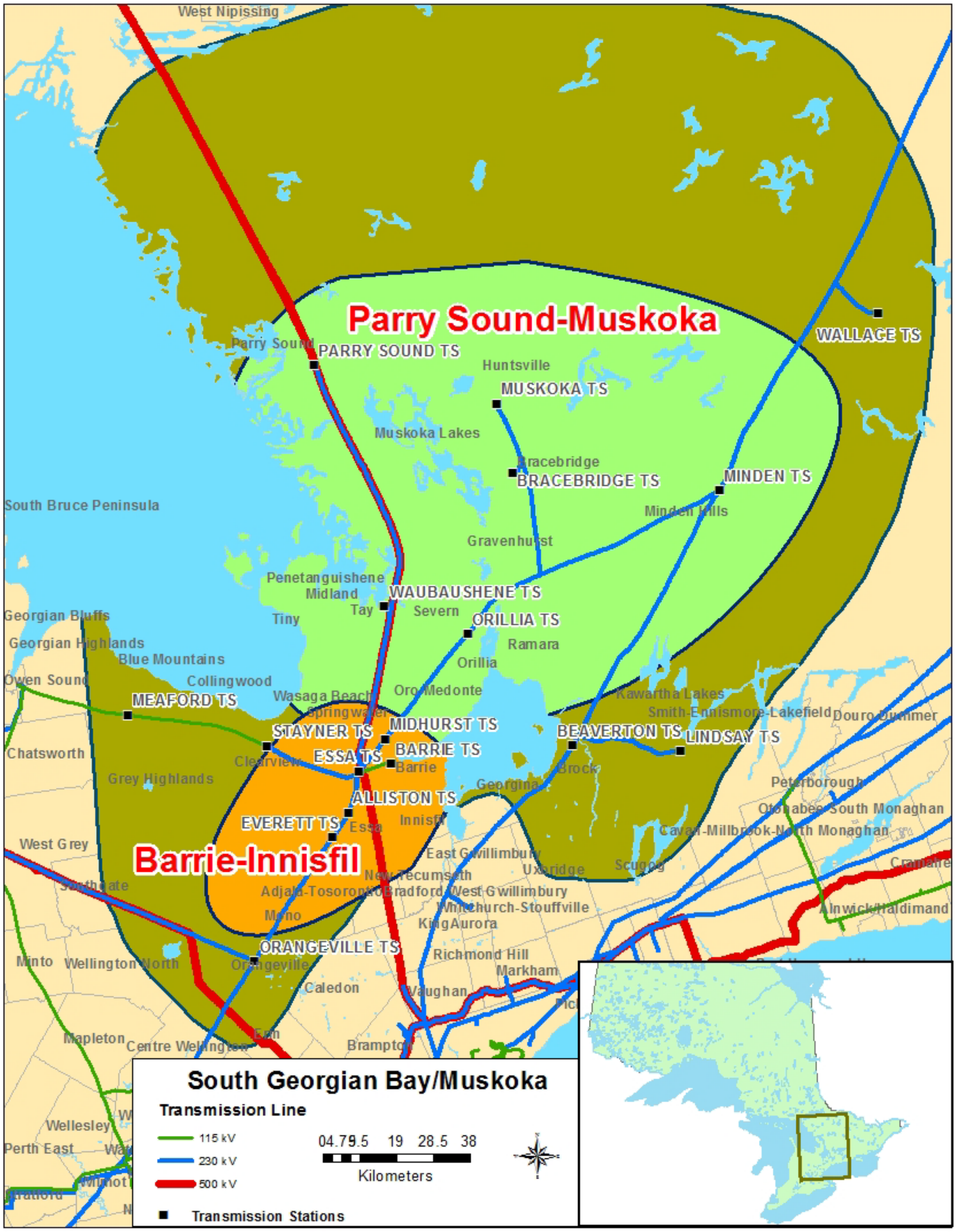
5.2.2.6 IESO

OHL has day-to-day interaction with the IESO through its regulatory, finance, and metering departments. Beyond this, OHL has minimal interaction with the IESO due to OHL being an embedded-LDC, the nature of the OHL's historical and proposed projects, and types of customers connected to OHL's distribution system. In November 2020, OHL joined the IESO's Regional Planning Municipal Outreach session for the South Georgian Bay/Muskoka area. This session re-confirmed that there were no projects or programs from the IESO that would impact OHL's planning process over the duration of this DSP. OHL will continue to engage the IESO with other industry partners as required, either for new Renewable Energy Generation ("REG") investments or to explore any future potential Conservation Demand Management ("CDM") initiatives that may arise. Consultations with the IESO, such as through the Regional Planning Process, did not affect the investments proposed in this DSP.

5.2.2.7 Regional Planning Process

OHL is a member of the South Georgian Bay/Muskoka Regional Planning Group which is roughly bordered by West Nipissing on the North-West, the Algonquin Provincial Park on the North-East, Scugog on the South, Erin on the South-West, and Grey Highlands on the West. This region is divided into two sub-regions: Barrie/Innisfil sub-region and Parry Sound/Muskoka sub-region. From a HONI and IESO perspective, the South Georgian Bay/Muskoka Region is within the Group 2 Region.

Figure 5.2-6: Map of South Georgian Bay/Muskoka Region



The first regional planning cycle for the region was completed in August 2017 with a documented Regional Infrastructure Plan ("RIP") completed in 2017. A Needs Assessments was completed in April 2020 as the start of the second planning cycle, with a second RIP completed in December 2022. OHL was a part of both the RIP and Needs Assessment team sessions led by Hydro One. The purpose of the Needs Assessment was to identify new needs for the region as well as recommend a path forward for each need by either developing a preferred plan or identifying which needs require further assessment and/or regional coordination. A technical assessment of needs was undertaken based on:

- Current and future station capacity and transmission adequacy.
- Any major high voltage equipment reaching the end of its life.
- Reliability needs and operational concerns.

There were multiple needs identified in the first and second planning cycle for the region, some of which pertained to or impacted OHL. In the first planning cycle, improvements and upgrades to Orangeville TS were identified. Orangeville TS was identified to be replaced in 2023 and is currently under construction. The implementation and execution plan for the replacement of the TS will be coordinated with Hydro One and does not require further regional coordination. A short description of the scope of Orangeville TS replacement is extracted from the latest Needs Assessment report:

> *Orangeville TS – Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units/ Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. These transformers and associated low voltage equipment have been assessed as being the end of life and in need of replacement due to asset conditions. This is presently underway with an in-service scheduled for 2023.*[2]

In the second phase of the regional planning process, an additional need to replace an aging line section was identified. From the 2022 RIP:

> *E8V/E9V Orangeville TS X Essa JCT – This is a 112km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2027.*

The initiative to be led by HONI will replace the transmission line conductor and associated assets and is estimated to cost $70 million.

A Local Plan was also developed for Orangeville TS End-of-Life Replacement completed in 2016. The report can be found on HONI's website here. The 2022 Regional Plan is also attached as Appendix G.

5.2.2.8 Telecommunication Entities

OHL maintains good relationships with third-party communications companies such as Bell, Rogers, Wightman, and Acronym, and OHL offers its support when requested. Communication between OHL and these entities remains open but occurs on an as-needed basis, such as when situations arise where the plant and personnel of either party may affect the operation of the other party. An example of projects where collaboration

[2] https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/southgeorgianbaymuskoka/Documents/South%20Georgian%20Bay%20-%20Muskoka%20Needs%20Assessment.pdf

may be necessary include the deployment of fibre-optic cable or dedicated locate assistance when deploying fibre to home.

As an example, in determining the schedule for the installation of ducts, OHL was engaged in talks with Wightman's contractor Avertex, as they were also going to be installing duct on behalf of Wightmans on the same boulevard. OHL was already in the initial planning stages with Avertex to install duct in September 2021 for project B118. This had been planned as an OHL-only installation with directional drilling. Avertex informed OHL of their routing and timing for the Wightman duct installation in October 2021. Avertex was going to be installing Wightman duct in the same boulevard that OHL required duct for B118, as well as B120, & B122 in the very near future. OHL decided to join Wightman's project and have Avertex install the fibre duct and electrical duct at the same time throughout late 2021, and 2022. With some project delays, the installation continued into early 2023.

In addition to these operational engagements, OHL is a member of the USF and the CHEC group and participates in projects run by these groups.

To date, nothing from OHL's engagement from any third-party groups has affected the development of this DSP.

5.2.2.9 CDM Engagements

The EDA and the Ontario Energy Association ("OEA") are working together to find a way to get LDC's to re-engage in CDM practices that are acceptable to all relevant stakeholders such as the IESO, OEB, and Ministry. Discussions are ongoing and OHL is ready to comply with any recommendations that are made.

Additionally, OHL promotes good, available CDM solutions to its customers. For example, OHL regularly engages with its customers through various social media channels to inform them about the IESO's Save-on-Energy program as well as provides energy saving tips on its website.[3]

5.2.2.10 Renewable Energy Generation

OHL currently does not anticipate any REG investments over the forecast period. OHL's REG investment plan is contained in Appendix F.

5.2.2.10.1 IESO Comment Letter

OHL does not anticipate any REG investments over the forecast period, and therefore has not sought a comment letter from the IESO.

[3] Energy and Water Saving Tips – Orangeville Hydro, Rebates & Financial Help – Orangeville Hydro, My Energy Action Plan – Orangeville Hydro

5.2.3 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

5.2.3.1 Distribution System Plan

5.2.3.1.1 Objectives for Continuous Improvement Set out in Last DSP Filing

One performance measure that has not been covered in section 5.2.3.1.2, that OHL reported in its last DSP, is System Losses.

OHL system losses over the historical period are shown below.

Table 5.2-2: Performance Measure - System Losses

Measure	2018	2019	2020	2021	2022	OHL Target
System Losses	3.65%	3.71%	3.47%	4.61%	1.96%	< 5.0%

Losses are averaging 3.3% over the historical DSP period, with the most recent reporting year being 2.8%. It is evident OHL is performing well for this performance measure over the average historical period, as well as the continuous improvement year over year in losses experienced.

5.2.3.1.2 Performance Scorecard

OHL's corporate emphasis on continuous improvement is reflected in all areas of its operations. Like most LDCs in Ontario, OHL must replace ageing, at risk of failure distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to the strategic replacement of ageing assets, OHL continues to focus on core maintenance activities to reduce the disruption of electricity distribution to customers. OHL focuses on short- and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

OHL monitors several performance measures, including those mandated by the OEB, that may assist in the utility's continuous improvement activities and satisfying customer requests. These measures can be divided into the following general groups:

1. Customer-oriented performance
2. Cost efficiency and effectiveness
3. Asset/system operations performance

Where applicable, the performance measures included on the scorecard have an established minimum level of performance to be achieved. The scorecard is used to continuously improve OHL's asset management ("AM") and capital planning process. OHL's current performance state is represented by OHL's official scorecard results for the recent historical year as published by OEB. The scorecard is designed to track and show OHL's performance results over time and helps to benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer. Table 5.2-3 summarizes OHL's performance during historical years from 2018 to 2022.

The guidance provided by the OEB in the recently published *Report of the Board: Electricity Distribution System Reliability Measures and Expectations* (EB-2014-0189), indicates that it would like to use the average or arithmetic mean of the previous five years (or historical period) of data to establish performance expectations for the forecast period. Specifically, the OEB referred to SAIDI and SAIFI as the two reliability indicators that would benefit from using targeted goals.

Each metric provided in the table and subsections below influences OHL's DSP to achieve the best performance for its customers. The following sections address performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements.

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in senior management review of performance cause. This may result in review and changes to processes in order to bring performance back to target levels. OHL has been and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers. The historical performance measures include 2018 to 2022 to have a complete five-year historical performance assessment.

Table 5.2-3: DSP Performance Measures

Performance Outcome	Measure	Metric	2018	2019	2020	2021	2022	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	100.00%	99.24%	100%	90%
		Scheduled Appointments Met on Time	99.76%	100.00%	100.00%	99.25%	100%	90%
		Telephone Calls Answered on Time	99.94%	99.90%	99.11%	99.21%	99.26%	65%
	Customer Satisfaction	First Contact Resolution	99.90	99.90%	99.90	99.83%	99.62%	No target
		Billing Accuracy	99.99%	100.00%	99.84%	99.82%	99.73%	98%
		Customer Satisfaction Survey	78.2%	78.2	76	76	76	No target
Operational Effectiveness	Safety	Level of Public Awareness	86.20%	85.50%	85.50%	84.50%	84.50%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	0	0	0	1*	0	0
		Rate per 10, 100, 1000 km of line	0.00	0.00	0.00	0.45	0.00	0
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	0.29	0.33	1.01**	1.75**	0.47	0.55
		Ave. Number of Times that Power to a Customer is Interrupted	0.16	0.39	0.75**	0.91**	0.52	0.65
	Asset Management	Distribution System Plan Implementation Progress	87%	96%	102	87%	156%	No target
	Cost Control	Efficiency Assessment	2	2	2	1	1	No target
		Total Cost per Customer ($)	551	568	535	550	605	No target
		Total Cost per km of Line ($)	$31,233	$32,501	$30,612	$31,921	$35,340	No target

Performance Outcome	Measure	Metric	2018	2019	2020	2021	2022	Target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	-	-	-	-	-	No target
		New Micro-embedded Generation Facilities Connected on Time	100.00%	-	-	-	-	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	1.56	1.74	1.41	0.78	1.39	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	1.05	1.15	1.12	1.12	1.28	No target
		Regulatory ROE – Deemed (included in rates)	9.36%	9.36%	9.36%	9.36%	9.36%	No target
		Regulatory ROE - Achieved	11.92%	10.36%	11.83%	9.46%	5.71%	No target

* This is due to an automatic tension sleeve failing resulting in the feeder tripping and live conductor falling to the ground in 2020. This incident was reported to the Electrical Safety Authority (“ESA”) and published in 2021. No injuries were reported to OHL employees or the general public. OHL quickly restored the conductor and carried out an infrared scan of that area and the entire service territory to detect other failing sleeves. A few of those sleeves were found to be hot and were immediately replaced. In 2021, OHL replaced the undersized conductors on Centennial Road with the latest conductors. OHL conducted an audit of their overhead system on all their distribution voltages. OHL plans to replace their automatic tension sleeves with compression sleeves over the forecast period. Further information can be found in the material narrative H00-2024.

** The reasons attributing to low reliability (i.e., SAIDI and SAIFI metrics) in 2020 and 2021 is summarized in Table 5.2-4.

Table 5.2-4: Justifications for SAIDI and SAIFI targets

Year	Month	Reason
2020	August	Automatic tension sleeve connector on 4/0 ACSR conductor failed causing an outage on the M26 27.6kV feeder.
2020	November	A foreign interference dig-in incident wherein a private contractor was excavating on an industrial property. The customer-owned fuses did not clear the fault before the M26 Feeder breaker operated which caused an outage to 4,170 customers.
2021	March	A pole fire due to a defective insulator.
2021	September	Rainstorm resulting in a large tree falling onto the M25 Feeder.
2021	October	A failed primary express elbow within a PME-9 unit.

OHL has implemented the following measures to maintain the SAIDI and SAIFI values over the forecast period:

- Planned renewal of end-of-life assets such as poles and cables.
- Proactive vegetation management.
- Replacement of automatic tension sleeves with full tension compression sleeves
- Inspection of the plant to identify potential problems.
- Testing of wood poles with a resistograph.
- Design and construction of distribution circuits to meet CSA-Heavy standards.

These activities and measures are explained in further detail within Appendix C of the DSP – OHL’s Distribution Maintenance Program.

5.2.3.2 Service Quality and Reliability

5.2.3.2.1 Service Quality Requirements

OHL has filed Chapter 2 Appendix 2-G Service Reliability and Quality Indicators in live excel format with this application. The data in Appendix 2-G as well as the tables included in this document are consistent with the scorecard. OHL discusses reliability below in section 5.2.3.2.2 Reliability Requirements.

OHL 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. Additional sub-measures are tracked as part of the DSC requirements. All these measures are self-explanatory, and all relate to OHL providing connection services as well as quality customer service. OHL is committed to meeting and exceeding all targets found in the Service Quality performance measure group.

Over the past years OHL has exceeded all measures including new services connected on time, scheduled appointments met, and telephone calls answered within 30 seconds. OHL attributes this success to its open-door policy to its customers. Employees answer the telephone themselves with only an IVR to direct calls when they are first received to the correct department and make personal arrangements for appointments. Customers are generally helped immediately with questions or issues at the first point of contact, whether by phone or in person. The following table presents the service quality metrics tracked by OHL along with OHL's historical performance records. Table 5.2-5 below presents only a subset of metrics, however, OHL's scorecard provides a detailed breakdown by sub-metrics.

Table 5.2-5: Historical Service Quality Metrics

Measure	Metric	2018	2019	2020	2021	2022	Target
Service Quality	New Residential/Small Business Services Connected on Time	100.00%	100.00%	100.00%	99.24%	100.00%	90%
	Scheduled Appointments Met on Time	99.76%	100.00%	100.00%	99.25%	100.00%	90%
	Telephone Calls Answered on Time	99.94%	99.90%	99.11%	99.21%	99.26%	65%

OHL exceeded the industry targets for each service quality measure. OHL's outstanding performance on these measures indicates no substantial additional material projects are required for investments in this area. OHL continues to strive to better serve the customer with the highest excellence. OHL's intended action for these measures is to maintain the performance.

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

First Contact Resolution

OHL measures this performance by logging all calls, letters, and emails received and track 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

OHL 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 OHL. OHL is proactive and reactive in its customer engagement consultations, the majority of which provide helpful insight into the day-to-day operations of OHL. OHL engages Advanis in collaboration with other CHEC member utilities to control costs and to conduct an independent biennial telephone-based customer satisfaction survey. 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 reviewed by the management team, incorporated into OHL's planning process and forms the basis of plans to improve customer satisfaction, meet the needs of customers, and address areas of improvement.

OHL sets a high standard for performance when it comes to customer care and is proud of the results. OHL strives to deliver customer excellence and value through the execution of its capital investments and operations. OHL believes they have delivered the intended performance for each metric delivering customer satisfaction demonstrating credibility and trust. Targets are established through a five-year moving average (see Table 5.2-6).

Table 5.2-6: Performance Measures - Customer Satisfaction

Measure	Metric	2018	2019	2020	2021	2022	Target
Customer Satisfaction	First Contact Resolution	99.9	99.90%	99.9	99.83%	99.62%	No target
	Billing Accuracy	99.99%	100.00%	99.84%	99.82%	99.73%	98%
	Customer Satisfaction Survey	78.20%	78.20	76.00	76.00	76.00	No target

OHL's performance on the measures indicates no substantial additional material projects are required. OHL continues to strive to better serve the customer with the highest excellence. OHL's intended action for the measure is to maintain the performance of the historical average.

Table 5.2-7 is an excerpt from Appendix 2-G filed with this application. All remaining measures not already discussed are within the OEB minimum standard.

Table 5.2-7: Appendix 2-G SQI: Service Quality

Indicator	OEB Minimum Standard	2018	2019	2020	2021	2022
Low Voltage Connections	90.0%	100.00%	100.00%	100.00%	99.24%	100.00%
High Voltage Connections	90.0%	100.00%		100.00%		
Telephone Accessibility	65.0%	99.94%	99.90%	99.11%	99.21%	99.26%
Appointments Met	90.0%	99.76%	100.00%	100.00%	99.25%	100.00%
Written Response to Enquires	80.0%	98.21%	99.58%	99.54%	98.64%	99.87%
Emergency Urban Response	80.0%	100.00%			100.00%	100.00%
Emergency Rural Response	80.0%					
Telephone Call Abandon Rate	10.0%	0.04%	0.06%			
Appointment Scheduling	90.0%	99.87%	100.00%	99.39%	94.52%	93.54%
Rescheduling a Missed Appointment	100.0%	75.00%				
Reconnection Performance Standard	85.0%	97.53%	95.88%	97.62%	100.00%	100.00%

5.2.3.2.2 Reliability Requirements

System reliability is an indicator of the quality of the electricity supply received by the customer. System reliability and performance are monitored via a variety of weekly, monthly, annual, and on-demand reports generated by the Smart Faulted Circuit Indicators, Customer Notification Bulletins from HONI, and the Outage Monitoring System ("OMS"). OHL collects and reports outage data using the standard format and codes specified in the "Reporting and record keeping requirements" (RRR) document. OHL utilizes other methods of data collection and cataloging such as trouble reports collected by field employees. Calculations are made to determine the reliability indices for SAIDI, SAIFI, and CAIDI. The data is sorted to determine frequency and duration for each feeder as well as to determine the cause and affected components.

The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's *Electricity Reporting & Record Keeping Requirements* dated May 3, 2016. SAIDI, or the System Average Interruption Duration Index, is the length of outage customers experience in the year on average, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute.

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

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

CAIDI or the Customer Average Interruption Duration Index is the average interruption time per customer affected and can be found by dividing the SAIDI value for the given year by the SAIFI value. CAIDI can also be viewed as the average restoration time.

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

Loss of Supply ("LOS") outages occur due to problems associated with assets owned by another party other than OHL or the bulk electricity supply system. OHL tracks SAIDI and SAIFI including and excluding LOS. 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 OHL (i.e., force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

OHL's reliability metric values for the historical period, adjusting for LOS and MEDs, are shown in the tables below.

Table 5.2-8: Historical Reliability Performance Metrics – All Cause Codes

Metric	2018	2019	2020	2021	2022	Average
SAIDI	0.39	1.05	1.40	1.90	3.33	1.61
SAIFI	0.35	1.08	1.01	1.09	2.32	1.17
CAIDI	1.11	0.97	1.39	1.75	1.43	1.33

Table 5.2-9: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2018	2019	2020	2021	2022	Average
	Loss of Supply Adjusted (including MEDs, Excluding LOS)					
SAIDI	0.29	0.33	1.01	1.75	2.94	1.26
SAIFI	0.16	0.39	0.75	0.91	1.44	0.73
CAIDI	1.81	0.85	1.35	1.91	2.03	1.59
	Major Event Days Adjusted (including LOS, excluding MEDs)					
SAIDI	0.39	1.05	1.40	1.90	0.86	1.12
SAIFI	0.35	1.08	1.01	1.09	1.40	0.99
CAIDI	1.11	0.97	1.39	1.75	2.66	1.58
	Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)					
SAIDI	0.29	0.33	1.01	1.75	0.47	0.77
SAIFI	0.16	0.39	0.75	0.91	0.52	0.55
CAIDI	1.80	0.85	1.35	1.91	0.92	1.37

In the above tables, the values for SAIDI and SAIFI metrics are higher than usual in 2020 and 2021 which is driving the average higher. This is due to multiple reasons and the explanation for these can be found in Section 5.2.3.1.2.

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

Figure 5.2-7: Performance Measure - SAIDI

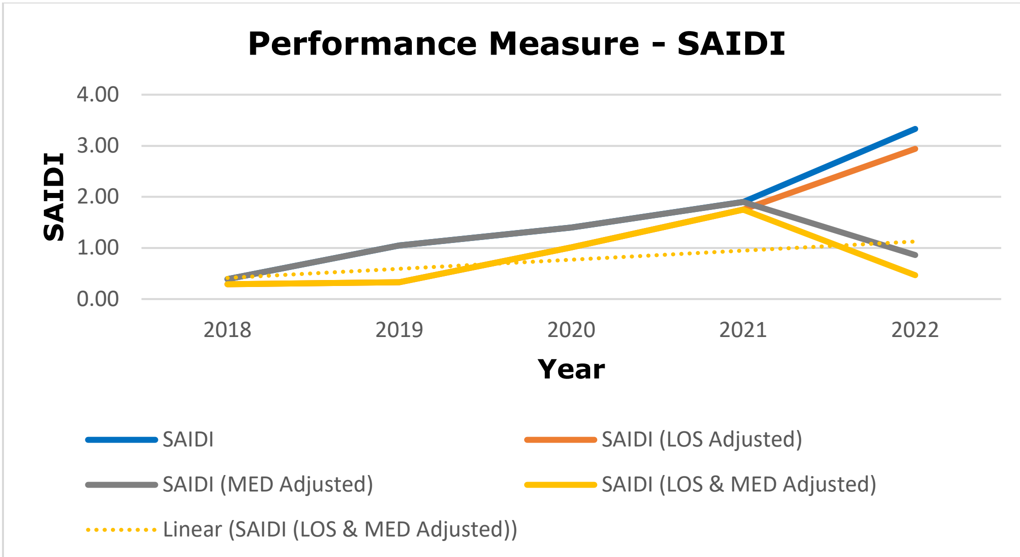


Figure 5.2-8: Performance Measure – SAIFI

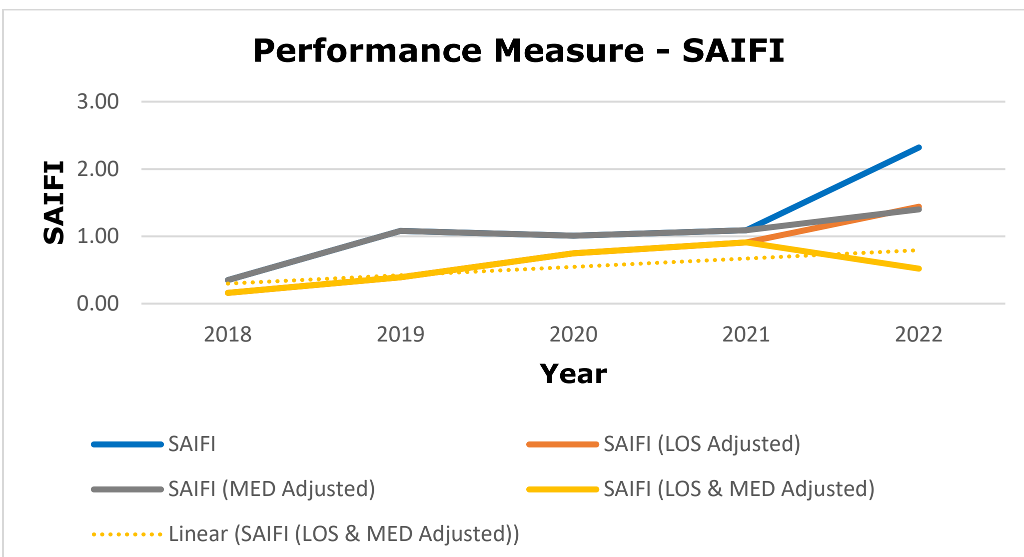
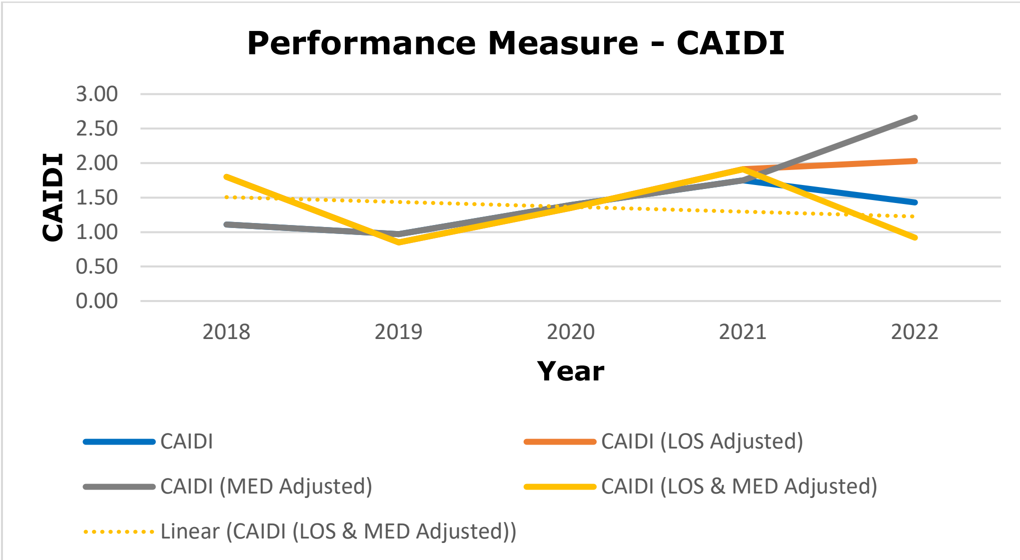


Figure 5.2-9: Performance Measure – CAIDI



OHL uses the SAIDI and SAIFI 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, OHL uses several programs to reduce the number of controllable outages. These programs include:

- Planned renewal of end-of-life assets such as poles and cables.
- Planned replacement of automatic tension sleeves.
- The completed replacement of legacy EPAC insulators.
- Proactive vegetation management.
- Inspection of the plant to identify potential problems.
- Testing of wood poles.
- Design and construction of distribution circuits to meet CSA-Heavy standards.

5.2.3.2.3 Outage Details for Years 2014-2022

The following sections and figures provide the breakdown of historical outages for the historical period regarding the number of outages, the number of customers interrupted, and the number of customer hours experienced by the outages. Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the historical performance range is used as a target and results outside this range indicate positive or negative trending. The following tables illustrate the number of MEDs over the historical period, the cause of them, and the customer hours interrupted.

Table 5.2-10: Summary of MEDs over the Historical Period

Year	# of MEDs	Cause of MEDs
2022	1	Significant winter blizzard on December 22 & 23
2017	1	A loss of supply event occurred on January 17 due to an ice storm.

Table 5.2-11: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
2022	5,400	Significant winter blizzard on December 22 & 23
2017	4,211	A loss of supply event occurred on January 17 due to an ice storm.

Table 5.2-12 presents a summary of outages that have occurred within OHL's service territory providing three different categorizations. A further breakdown by cause codes is provided in the following subsections.

Table 5.2-12: Number of Outages (2018-2022)

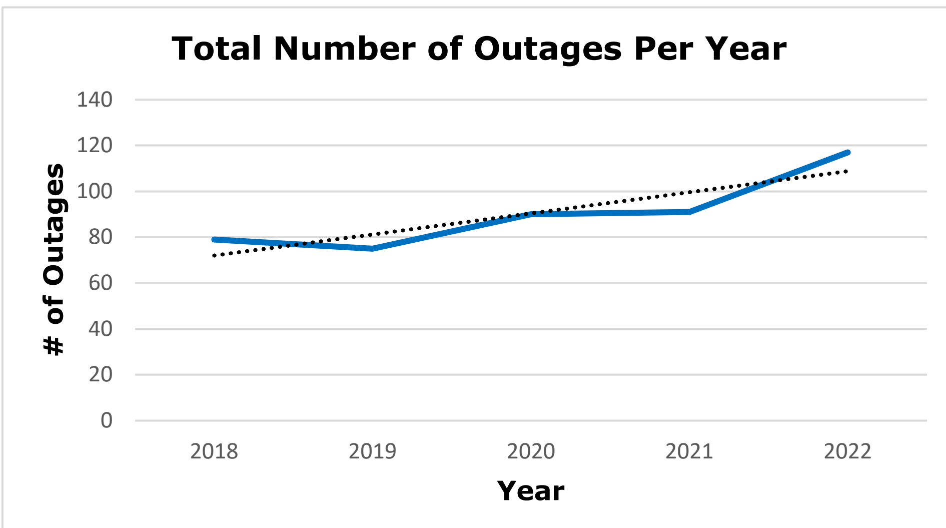
Categorization	2018	2019	2020	2021	2022
All interruptions	79	75	90	91	117
All interruptions excluding LOS	78	72	88	89	109
All interruption excluding MED and LOS	78	72	88	89	109

Table 5.2-13 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. OHL continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-13: Outage Numbers by Cause Codes

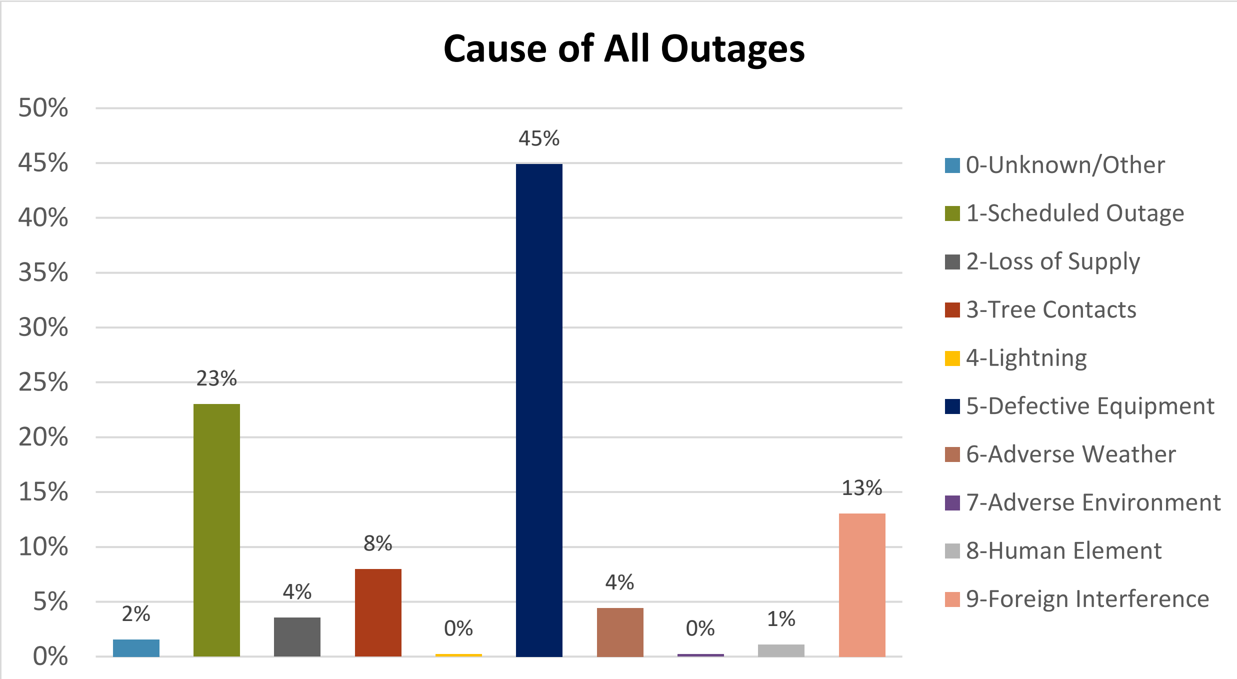
Cause Code	2018	2019	2020	2021	2022	Total Outages	%
0-Unknown/Other	-	5	2	0	0	7	2%
1-Scheduled Outage	19	8	13	13	51	104	23%
2-Loss of Supply	1	3	2	2	8	16	4%
3-Tree Contacts	8	1	6	10	11	36	8%
4-Lightning	-	1	-	0	0	1	0%
5-Defective Equipment	40	42	47	49	25	203	45%
6-Adverse Weather	4	1	10	0	5	20	4%
7-Adverse Environment	-	1	-	0	0	1	0%
8-Human Element	-	2	-	1	2	5	1%
9-Foreign Interference	7	11	10	16	15	59	13%
Total	**79**	**75**	**90**	**91**	**117**	**452**	**100%**

Figure 5.2-10: Total Number of Outages per Year



The total number of interruptions over the historical period varies from a low of 75 to a high of 117, with the overall trend increasing in the period. This represents an average of 0.205 to 0.321 interruptions per day. The top three cause codes ranked by percentage share over the historical period are *Defective Equipment, Scheduled Outage,* and *Foreign Interference.* A summary of the causes of outages within OHL's system is presented in Figure 5.2-11 along with the percentage of overall outage incidents attributable to each cause type.

Figure 5.2-11: Percent of Outages by Cause Code



Defective Equipment outages are a major contributing cause (one of the top three) to the total outages, total customers interrupted, and customer hours interrupted. *Defective Equipment* outages accounted for 45% of the total outages experienced at OHL. These failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. OHL has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. OHL utilizes evaluations such as the Asset Condition Assessment to assist in prioritizing investments in asset classes.

The majority of these defective equipment causes are listed below:

- Single Customer Service Wire/Connector Issue – The majority of outage incidents under *Defective Equipment* are issues related to a single customers service such as an underground service conductor burn-off or an overhead service wire connection failure. These issues normally one affect one customer and do not have a significant impact on the systemwide SAIDI and SAIFI values but do increase the number of outage incidents. The below causes have a more significant impact on the systemwide SAIDI and SAIFI values.
- Automatic Sleeve Failure – OHL has a replacement program to address these during the forecast period.
- Insulator Failure – OHL staff and contractors have replaced the legacy EPAC insulators on OHL's system.
- Porcelain Cutout Failure – OHL is continuing with its replacement program of replacing porcelain cutouts with polymer cutouts.
- Elbow Failure on a 600A Express in a PME – OHL is continuing with its infrared scanning program and started an ultrasonic partial discharge scanning program. In addition, OHL has trained staff on improved installation techniques.

- PME Failure – OHL has a formal PME replacement program.

Scheduled Outages have remained steady over the historical period due to the execution of OHL's plans. Over the historical period, it has contributed to 23% of the total number of outages that occurred. These outages are due to the disconnection of service for OHL to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. A significant capital investment that contributes to this cause code is OHL's ongoing conversion from 4.16 kV to 27.6 kV system as this requires periodic disconnections. OHL continues to plan capital work and maintenance appropriately in times that would affect minimal customers and with short durations.

Foreign Interference continues to be a major top contributing cause to the total outages, total Customer Interruptions and Customer Hours Interrupted. The outages contributing to the cause include dig-ins, vehicle collisions, animal interference, 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 OHL 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.

Tree contacts continues to contribute to the cause of outages. After the 2013 and 2016 ice storms, OHL increased tree trimming activities with internal staff. In order to maintain reliability and reduce the risk of significant outages during storms, increased labour hours were spent on tree trimming activities. In 2016, OHL began a formal rear-lot line clearing program. OHL's rear-lot infrastructure that was inaccessible for OHL trucks was divided into seven Zones. An Arborist Contractor is utilized each year to complete the line clearing activities within one or two of the seven zones. This program did not exist in 2014, therefore, this is a net-new program with new costs. This program is required to maintain reliability, reduce the risk of challenging outages during ice/windstorms, reduce fire concerns, and reduce the risk of electrical contact from children climbing trees. This program is further justified through the requirements of the IHSA Safe Practice Guide for Line Clearing Operations and Regulation 22/04: Electrical Distribution Safety. OHL's line clearing program has been created to comply with our mandatory obligations, maintain reliability, reduce the risk of fires, and reduce the risk of electrical contacts from children climbing trees near overhead wires.

Loss of Supply outages attributed to a small share of only 4% of the total outages throughout the historical period but accounted for 37% of total Customers Interrupted ("CI") and 22% of total Customer Hours Interrupted ("CHI"). These outages are due to problems associated with assets owned outside of OHL in which OHL has no control over nor does it maintain. Although *Loss of Supply* outages have minimal contribution in terms of outage counts, they have a significant impact on the total CI and CHI. One outage can affect a whole portion of OHL's system and may give OHL limited switching capability, resulting in customers' power not being restored quickly.

The number of CI is a measure of the extent of outages. 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 5.2-14: Customers Interrupted Numbers by Cause Codes

Cause Code	2018	2019	2020	2021	2022	Total CI	%
0-Unknown/Other	-	92	48	0	0	140	0%
1-Scheduled Outage	199	259	208	238	729	1,633	2%
2-Loss of Supply	2,353	8,779	3,300	2,226	11,318	27,976	37%
3-Tree Contacts	183	1	7	2,479	5177	7,847	10%
4-Lightning	-	1	-	0	0	1	0%
5-Defective Equipment	1,325	262	4,695	8,799	311	15,392	21%
6-Adverse Weather	162	12	242	0	11,936	12,352	17%
7-Adverse Environment	-	-	-	0	0	12	0%
8-Human Element	-	49	-	22	22	93	0%
9-Foreign Interference	187	4,207	4366	205	398	9,363	13%
Total	**4,409**	**13,662**	**12,866**	**13,969**	**29,891**	**74,809**	**100%**

Figure 5.2-12: Total CI over historical years

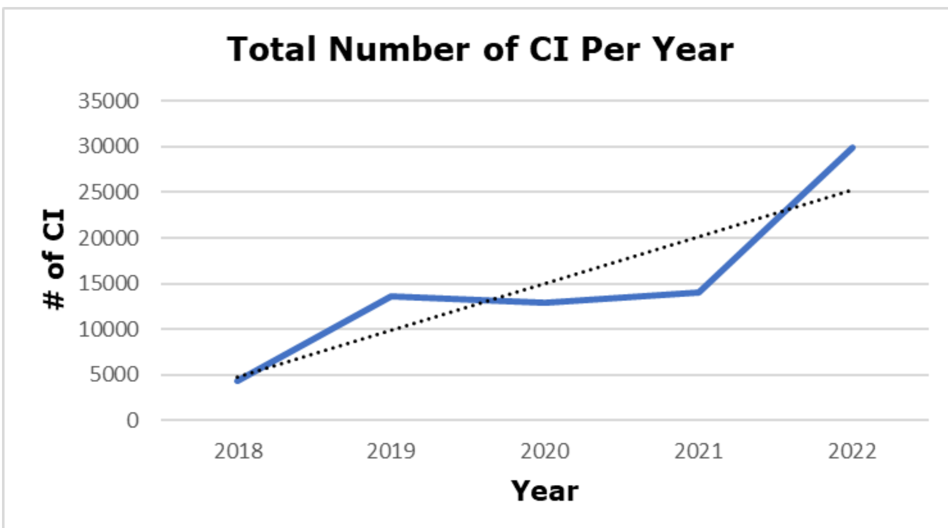
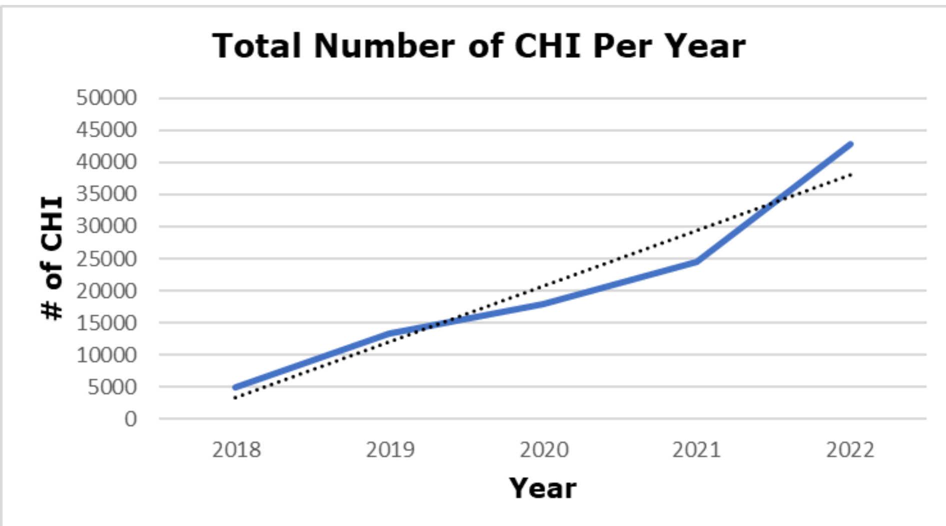


Table 5.2-15: Customer Hours Interrupted Numbers (rounded) by Cause Codes –

Cause Code	2018	2019	2020	2021	2022	Total CHI	%
0-Unknown/Other	0	90	56	0	0	146	0%
1-Scheduled Outage	426	534	420	2,187	1,628	5,195	5%
2-Loss of Supply	1,216	9,147	5,065	1,966	5,007	22,401	22%
3-Tree Contacts	295	2	66	4,083	3,556	8,002	8%
4-Lightning	0	1	-	0	0	1	0%
5-Defective Equipment	2,692	431	6,131	15,598	429	25,281	24%
6-Adverse Weather	108	12	3,300	0	31,772	35,192	34%
7-Adverse Environment	0	12	-	0	0	12	0%
8-Human Element	0	54	-	266	12	332	0%
9-Foreign Interference	189	3,024	2,850	295	456	6,814	7%
Total	**4,926**	**13,307**	**17,888**	**24,395**	**42,860**	**103,376**	**100%**

Figure 5.2-13: Total CHI over historical years



An increasing trend is seen for both the total customers interrupted and customer hours interrupted over the historical period. As seen in the tables, the top cause code that can be controlled and managed by OHL is *Defective Equipment.* OHL proposes continued investments into its AM strategy to manage the impact of outages on the total CI and CHI.

There have been nine main drivers for 85% of the outages over the last 5 years. OHL have analysed these outages, and this has driven OHL to:

1. Work with Hydro One and request resolution to upstream issues.
    a. OHL requested Hydro One install fuses on unfused radial upstream of OHL demarcation.
    b. OHL requested galloping conductor mitigations, resulting in Hydro One installing interphase spacers upstream of OHL demarcation.

   c. OHL has requested changes to the Hydro One Protection and Control settings to reduce nuisance momentary outages to OHL customers. This is expected to take effect in 2024 after the Orangeville TS upgrades.
   d. Hydro One will be rebuilding the Grand Valley DS which will reduce animal contacts within the Grand Valley DS.
2. Increase vegetation management activities as compared to 2014
   a. Also, OHL works with the municipalities to identify and request removal of dead/dying trees that are high risk to OHL pole lines
3. Replace all EPAC insulators to avoid additional pole fires
4. Replace porcelain switches and cutouts during planned maintenance and capital programs
5. Start the Automatic Tension Sleeve Replacement program in 2023
6. Begin Ultrasonic Partial Discharge testing on primary express infrastructure and retrain staff on primary elbow installation practices.
7. Promote Ontario One Call's call/click before you dig through social media as well as work with Locate Service Provider to increase number of locators to ensure compliance with Ontario One Call and meet excavators' timelines for receiving locates.

5.2.3.3 Distributor Specific Reliability Targets

OHL does not use any additional metrics to track its reliability, beyond what is reported to the OEB.

5.3 Asset Management Process

5.3.1 Planning Process

5.3.1.1 Overview

Key elements of the process that drive the composition of OHL's proposed capital investments are highlighted along with OHL's asset management philosophy. The relationship between the Renewed Regulatory Framework for Electricity ("RRFE") outcomes, corporate goals, asset management objectives, and the linkage to the selection and prioritization of OHL's planned capital investments is explained which controls OHL's financial performance and planning.

The components of the asset management process that OHL has used to prepare its capital expenditure plan are identified, including data inputs, preliminary process steps and outputs. The information generally used throughout the DSP is based on available information established at the given moment.

OHL's asset management objectives 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 OHL's electrical distribution system. The objectives guide OHL 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 OHL's capital investment process to identify, select, and prioritize investments for each planning cycle. Furthermore, the objectives are in harmony with the corporate values, vision, and mission statement. OHL's 2023 Business Plan is attached in Appendix A which contains its strategic objectives.

OHL prepares its capital plans with consideration to business risks known to the utility. Preparations include consultations with key parties, incorporating historical performances into actionable items for the forecast plan, tailoring asset management goals, processes and practices and adopting the latest industry standards to achieve the best value out of its system while managing the risk categories such as safety, cybersecurity, and changing environments. OHL relies on a set of tools to assist in achieving the desired goals with consideration to corporate business risk. To support the tools and methodologies, a set of planning assumptions and criteria are applied to reflect OHL's system.

5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

Since OHL submitted its last DSP only 2 years ago, OHL has not made any further significant changes to the asset management process. OHL, over the next few years, will continue to review the efficacy of its process and make updates as required.

5.3.1.3 Process

Planning Criteria & Process

OHL, like other distribution utilities, strives to ensure its distribution system provides a reliable level of service to customers and connection capacity for forecasted demand growth and as such must be able to handle customer supply needs during normal and certain contingency situations. Overloading of distribution equipment, because of inadequate investment, is avoided as much as possible.

It is OHL's planning policy that the distribution networks shall be designed, constructed, operated, maintained, and renewed in an efficient manner which:

- Supports OHL's strategic goals and asset management objectives.
- Supports the OEB's RRFE outcomes.
- Implements OHL's business plan.
- Complies with regulatory and statutory requirements.
  - Health and safety of workers and the public.
  - Electricity supply quality and reliability.
  - Environmental Protection.
  - Good utility practice.
  - Financial and IFRS accounting practice.
- Effectively controls and balances service levels with asset lifecycle costs and risks.

With its corporate emphasis on business performance and accountability, OHL has developed a capital budget process and system of prioritization. This system reflects its long-term investment strategy, recognizes shorter-term requirements, and can address the ongoing need for OHL to respond to external and internal priority changes. It respects the priorities of a wide range of stakeholders, OHL's corporate strategies and regulatory requirements. OHL's asset management process is shown in the figure below which OHL leverages to identify, select, develop, prioritize, execute, and monitor its investment plans.

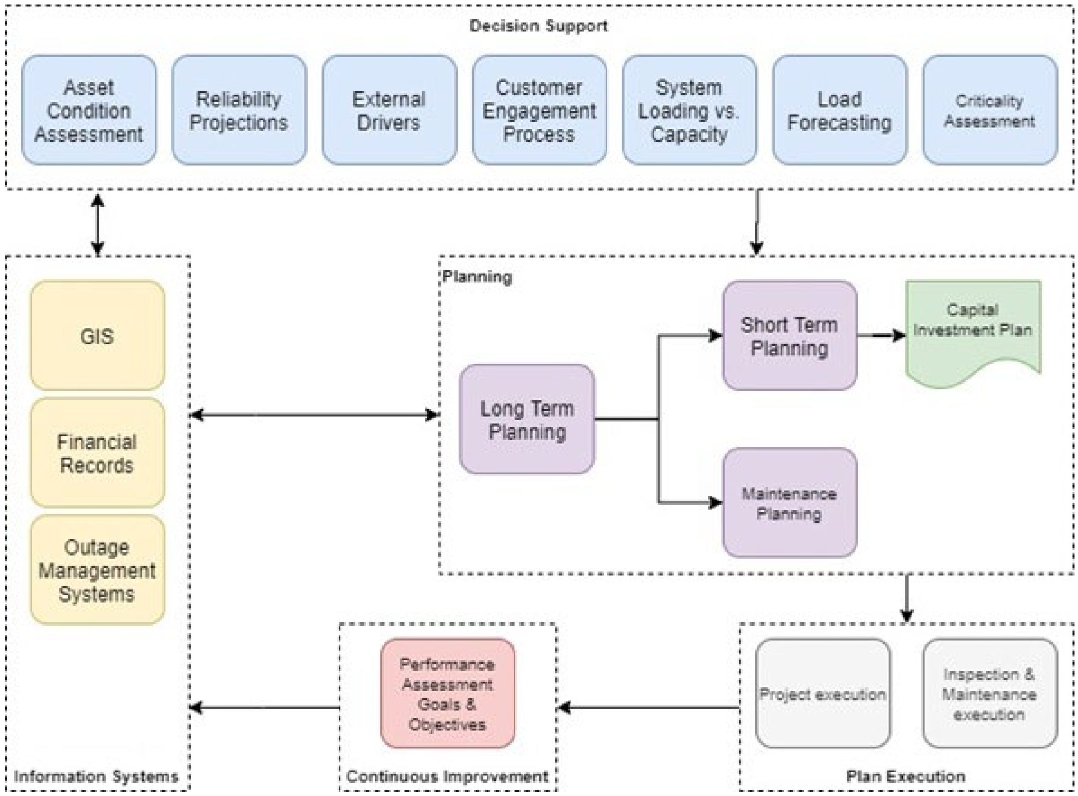
OHL's asset management process is established in a way to coordinate activities to ensure the assets are optimally achieving the company's corporate and asset management objectives. Conceptually, the process includes items such as setting out the criteria for optimizing and prioritizing asset management 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. OHL's process is visualized in the Figure 5.3-1. The process contains five elements and is an iterative process:

- Information Systems
  - These are the systems, where the key input data is collected and fed into supporting the activities within the Decision Support element and into the development of OHL's investment plans.
- Decision Support
  - The activities within this element of the process are fundamental to developing the key information that will support OHL in developing its

investment plans. This includes activities that cover both asset information and customer information and look at the impacts it has on the system in terms of capacity and asset health. This includes load forecasting, where OHL looks to continually improve to take account for items such as potential increase in EV vehicles, building electrification etc. Where appropriate OHL also would carry out a sensitivity analysis to account for uncertainty it forecasts.

- Planning
    - Within this section OHL takes a combination of inputs from its decision support outputs, other data and information from its information systems, and develops its investment plans. These include the development of a 5-year plan, maintenance plan, and the overall capital plan.
    - It should be noted that this is a continuous cycle, and new information is regularly collected, these plans are updated and changed on a regular basis to ensure OHL continues to deliver on its corporate and AM objectives.
- Plan Execution
    - Once OHL has developed its plans, it develops the execution plans, which include the execution of capital projects, and its maintenance execution plans. This includes the development of what resources are required, materials etc.
- Continuous Improvement
    - This section is where OHL continually tracks its progress in the execution of its investment plans. This information, including new asset information, testing, and maintenance data is inputted into the various information systems. This data then feeds back into the decision support and planning sections of OHL's AM process.

Figure 5.3-1: OHL's Asset Management System



The goals and objectives used throughout OHL's asset management approach are embedded within the asset management system to integrate continuous improvements in OHL's plan. This includes any key tactical initiatives that help achieve the objectives. The goals and objectives, once identified, have targets established that determine the measure of success of the asset management programs and practices. Conceptually, objectives revolve around, but not be limited to safety, reliability, and cost-efficiency.

Planning Assumptions

As part of the DSP and the plans outlined, the following assumptions are applicable:

- Equipment maintenance, refurbishment and replacement programs are in place to ensure that the capacity and capability of the distribution system are maintained at a reasonable level of risk of disruption due to lifecycle-related equipment failure.
- Incidences of extreme weather continue to be manageable under existing standards of design and construction.
- Historical trends continue unless other information is available otherwise.
- The level of activity in REG continues to be in alignment with historical connection requests or more likely to be less due to the end of the Feed-In-Tariff program.
- External assumptions such as limited growth found in the municipality and developers of the region are held constant and up to date.
- OHL, when identifying any assets for replacement, considers the future capacity requirements such that it does not need to be replaced prematurely due to capacity restraints.

- OHL connected approximately 65 new customers per year over the last 5 years. OHL anticipates that this rate to increase through the forecast period and has budgeted for this in its capital plan under System Access projects.
- CDM- OHL considers CDM activities where appropriate. Currently no viable CDM options are available or mandated through the IESO. OHL will continue to monitor and provide CDM options as they become available.
- Load Forecasting – OHL undertakes load forecasting which helps OHL understand the potential impact future loads could have on its network. With a focus on an increase in potential electrification of both vehicles and building heating, OHL has begun to look at the potential impact these could have on OHL's network. As with all forecasts, OHL also looks at sensitivity analysis of its forecasts to account for uncertainties of what may happen in the future. It should be noted that currently OHL does not foresee any short-term issues during the forecast period, and OHL has capacity accommodate the future growth it has currently forecast.

Project Identification

Capital spending is driven by customer value and capital needs identification through OHL's asset management process.

System Access projects such as development and municipal plant pole relocation projects are identified throughout the year by way of engagement with external proponents. These projects are mandatory and are budgeted and scheduled to meet the timing needs of the external proponents.

System Renewal projects are identified through OHL's asset management process. The project needs for a specific period are supported by a combination of asset inspection, individual asset performance, and asset condition assessments as summarized in the asset management process.

System Service projects are identified through OHL's asset management process and operational needs to ensure that any forecasted load changes that constrain the ability of the system to provide consistent service delivery are dealt with promptly.

General Plant projects are identified internally by specific departments (engineering, finance, operations, administration, etc.) and supported through specific business cases for the specific need.

Project Selection, Risk Management, and Prioritization

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. For discretionary investments across System Renewal, System Service and General Plant, a number of prioritization factors are considered. These factors align with OHL's corporate and AM objectives:

- Safety – projects that are considered to address safety as a primary factor.
- Reliability & Performance – projects that help OHL maintain or improve its reliability and meet other OEB performance measures.

- Asset Condition – projects that address assets that are at risk of failure as identified through both asset condition assessments, and inspection and maintenance information.
- Customer Focus – projects that enable OHL to address customer priorities and continue to deliver excellent service to its customers.
- Best Practice – projects that enable OHL to address assets that are no longer considered best practice and are impacting OHL's performance.

These projects are selected and prioritized based on value and risk assessments for each project against the objectives outlined above. Evaluating the absolute or relative importance of these proposed investments can be an intricate task as they may have competing requirements for available resources in any year. Whilst a list of projects may be prioritized using these criteria, within the execution year, the end decision of whether to proceed with an individual project in the current year is made by senior management based upon the best information available at the time.

Project Pacing

Project pace for System Access projects is generally determined by external schedules and needs. Although System Renewal, System Service and General Plant projects tend to be uneven and most are paced to begin and be completed within a particular budget year, OHL takes efforts to minimize the variance of the budget within a given fiscal year. These three investment types are paced with consideration of available resources and managing the program cost impacts on the customer's bill.

5.3.1.4 Data

OHL uses several 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. The main elements OHL considers within the asset management process (but not limited to) include:

- Information Systems
- Inspection & Maintenance
- Asset Condition Assessment
- Reliability Analysis
- System Loading & Capacity
- Customer Engagement
- External Factors
- Growth studies

Information Systems

The goal of the information systems is to contain the relevant information for ongoing development and optimization of assets inspection, maintenance, refurbishment, planning, replacement, support regulatory/legislative compliance and support IFRS accounting standards. OHL's information systems (GIS & separate field inspection management platform) are the designated asset registers for field assets and serves as accurate models of OHL's physical electrical distribution system. The information in the GIS, such as location, and specifics of the asset in whole describe the asset. The separate field inspection management platform contains inspection records and asset ratings. OHL's GIS & separate field inspection management platform asset database contains the asset source data that supports the ACA process as well as the capital planning process. Asset data in the GIS is captured from a multitude of sources including, but not limited to construction as-built records and legacy records.

Inspection & Maintenance

The goal of the inspection and maintenance is to be compliant with standards and codes and to leverage the results from the programs to prioritize and plan for asset interventions in any year. OHL maintains a full schedule of distribution asset inspection and maintenance programs operating on a fixed-year rotation as required by the OEB's DSC. Inspection, maintenance, and operational data are collected and stored which is used to support OHL's asset condition assessments which are input for developing operating and capital expenditure plans.

Asset Condition Assessment

The goal of the asset condition assessment is to interpret the inspection and performance data of key assets to assess the overall condition of the asset. The ACA is a key supporting tool for developing an optimized lifecycle plan for asset sustainability with a prioritized list of assets that require capital intervention. Under the proposed capital plan, 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.

Reliability Analysis

The goal of the reliability analysis is to identify and manage the leading outage causes that affect the overall performance and service quality experienced by customers. Outage causes are analyzed for each feeder to evaluate feeder outage risk and develop prioritization for evaluation in the current capital investment planning process. The analysis is used to inform OHL's asset management process in developing the O&M programs and capital expenditure plan for each year.

System Loading & Capacity

The goal of system loading and capacity is to identify, assess, and manage system constraints found on feeders as a result of increasing customer connections, customer load increase or renewable energy generation connections. The information is collected on system peak loading at many points in the system including OHL supply point meters, substation feeder measurement devices and sub-feeder load measurement devices. The data is analyzed as needed to measure the risk of system overloading and to mitigate any concerns.

External Factors

External drivers may sometimes influence OHL's decision-making in determining the optimal plans for their system. OHL continues to remain cognizant of these external drivers when developing its capital and maintenance plans.

External drivers include:

- Political – governments have their directions and strategies that OHL needs to be mindful of and to be in alignment with their plans.
- Economic – economic growth and decline within OHL'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 OHL'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.

Growth Studies

The goal of growth studies is to inform and plan accordingly for any future connections that may be requested by customers. OHL leverages the studies led by the municipalities and regional districts to plan allocate appropriate capital budgets and prioritize resources for the projects. Furthermore, this also considers any municipal renewal projects where OHL may have to relocate their assets or work together with the municipality for efficiencies. OHL monitors the development of any relevant studies annually to appropriately adapt and reflect current conditions and projections within its plans.

Tools

Engineering Analysis

OHL Engineering staff can utilize the loading data from the Advanced Metering Infrastructure (AMI) networks and the Operations Data Storage (ODS) for loading analysis of transformers and services. Before the AMI and ODS, field staff were required on-site to install monitoring equipment. The AMI and ODS have reduced the trucking and labour required to analyze the loading of transformers and services. This loading data has also been used to confirm the most appropriate size of equipment required to service particular loads. This has ensured the most appropriate and cost-effective equipment is installed. This optimization includes a reduction in transformer sizes.

OHL's AMI also provides Engineering staff with voltage information at the service delivery point. OHL staff can utilize this information as opposed to attending multiple sites and installing voltage monitoring equipment. The AMI has reduced the trucking and labour required to analyze the voltage at service delivery points.

Asset Management System (GIS) Implementation

The utility asset information is maintained in two separate repositories: The GIS and the separate field inspection management platform. This information is used engineering, operations, and finance departments. The GIS provides a network connectivity model, which more accurately represents the impact of assets on one another.

The model would also be a foundation for system analysis studies, which has been essential for addressing historical REG applications and assessing their potential impacts on the OHL distribution system.

SCADA

The OHL distribution system is relatively compact. The response to trouble calls and outages is within industry norms, as is evidenced by the performance indicators. The need for remote control of switching equipment at this time is minimal. However, as systems become more complex due to distributed generation requirements, system control and operation will also become more complex, and the supporting systems will need to be sophisticated enough to support these operational needs.

Outage Management and Reliability

OHL has utilized the Sensus AMI and the Savage Data ODS to build an Outage Management System at no additional cost from either party. OHL staff receive near real-time visual notification of all Power Fails, Power Restores, Voltage Dips and Meter Tampers that are reported by the smart meters. This has been utilized to decrease the lag between the start of an outage and OHL's awareness of the outage. This decrease in lag reduces the length of outages experienced by customers. The OMS also provides additional information to help determine the scale outages, and whether a problem is on the customer's side of the demarcation point. In some cases, OHL can restore power to customers before the customers become aware of the event. The OMS has deferred further investment in other systems such as other outage management systems, "smart" technologies, and a SCADA system. If addition to the OMS, OHL has installed smart faulted circuit indicators on all main feeders to monitor loading as well as receive alerts regarding loss of supply or downstream fault current details.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of Service Area

5.3.2.1.1 Overview of Service Area

OHL is an urban electric distribution company servicing the Town of Orangeville and the Town of Grand Valley with a total service area of 17 km^2, a municipal population of approximately 34,000, a customer base of 12,846[4] and a mainly summer peaking load. Figure 5.3-2 below depicts OHL's service areas.

[4] Customer base as of end of 2022.

Figure 5.3-2: Service areas for OHL

5.3.2.1.2 Customers Served

In 2022, OHL served 12,846 electricity distribution customers across its service area. The table below presents OHL'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. The table does not include USL, sentinel, and streetlight counts.

Table 5.3-1: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2022	11,560	1,161	125	12,846
2021	11,483	1,168	124	12,775
2020	11,409	1,164	124	12,697
2019	11,360	1,160	132	12,652
2018	11,285	1,164	134	12,583

5.3.2.1.3 System Demand & Efficiency

The table below shows the annual peak demand (kW) for OHL's distribution system.

Table 5.3-2: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2022	43,994	49,506	43,117
2021	41,873	49,837	42,117
2020	42,683	51,287	41,557
2019	43,212	45,153	39,868
2018	42,821	48,441	42,145

The total OHL system has remained stable in size and has been consistently summer peaking. It should be noted that the Town of Orangeville is a consistently a summer peaking community while the Town of Grand Valley recently switched from winter peaking to summer peaking. Peak data shown includes the net effect of embedded loads and generators. Variances in the seasonal peaks are attributable to weather temperature in both winter and summer and loading impacts associated with the number of degree days. Table 5.3-3 indicates the efficiency of the kilowatt-hour purchased and delivered by OHL.

Table 5.3-3: Efficiency of kWh Purchased by OHL

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2022	268,116,946	275,958,140	2.92%
2021	260,728,374	286,727,922	3.07%
2020	254,347,083	263,490,930	3.60%
2019	252,725,978	261,942,354	3.66%
2018	256,748,352	266,473,256	3.79%

5.3.2.1.4 Summary of System Configuration

OHL's distribution system is made up of approximately 75 kilometers of overhead primary circuits, 146 kilometers of underground primary circuits, 1,707 poles, and 1,337 distribution transformers.

OHL's distribution system is embedded in the distribution system of HONI. All OHL feeders are connected to the HONI owned Orangeville TS. The Town of Orangeville is fed from one express 44kV feeder (M5), one express 27.6kV feeder (M26) and two shared 27.6kV feeders (M25 and M23). OHL owns three 4.16kV distribution stations that are connected to the M5 feeder that supplies the older areas of the Town. The Town of Grand Valley is fed from one 12.47kV feeder (F2) that is connected to the HONI owned Grand Valley DS. The Grand Valley DS is fed from a HONI-owned 44kV feeder (M2).

OHL's distribution plant consists of a sub-transmission network at 44kV and 27.6kV with distribution substations at 12.47kV and 4.16kV. OHL is continually completing voltage conversion projects to convert the 4.16kV network to 27.6kV.

OHL manages the following Municipal Substations that supply the older areas of the Town of Orangeville. The Grand Valley DS is owned and managed by HONI.

Table 5.3-4: OHL Municipal Station Nameplate Information

Station Name	Transformer Manufactured Year	Capacity	# of Feeders	Type of Protection
MS 2	1975	5 MVA	2	Fused
MS 3	1967	5 MVA	2	Fused
MS 4	1977	5 MVA	2	Fused
Grand Valley DS	Owned by Hydro One	3 MVA	1	Oil Reclosures

5.3.2.1.5 Climate

Orangeville and Grand Valley are in South-Central Ontario, in the Dufferin County. The climate in OHL is described as cold and temperate, with significant precipitation throughout the year. The average temperature in Orangeville and Grand Valley is 6.7°C and ranges between -10 °C and 25°C. About 922 mm of precipitation falls annually with a monthly average of 97mm[5]. The service area experiences an average of 120 to 140 frost-free days, typically beginning late in May and ending late September.

5.3.2.1.6 Economic Growth

The Town of Orangeville undertook a five-year review of the Official Plan, which sets out in general terms, the pattern by which Orangeville will grow over a 20-year horizon and provides planning policies to guide the physical, social, and economic development of Orangeville. At the time of the review, Orangeville's population was 29,540 and is forecasted to reach a population of 36,490, a growth of 6,950 persons[6]. Furthermore, Grand Valley is anticipated to have an accelerated population and employment growth over the coming year. Population growth is forecasted to increase from 2,965 people to 7,478 people by 2031[7]. OHL is required to work with the town to connect new customers and accommodate the growth with appropriate upgrades and renewals of the system. OHL's existing and new customers expect to receive reliable service. To address this, OHL is constantly engaging with its customers to understand issues that are faced and develop plans to improve the service they are receiving.

Furthermore, OHL experiences a lower customer growth rate as compared to the Greater Toronto Area ("GTA"), resulting in fewer investment dollars to be secured for addressing all residential concerns while balancing with the identified system needs. In response to this OHL attempts to manage significant rate spikes.

5.3.2.2 Asset Information

5.3.2.2.1 Asset Capacity & Utilization

The Town of Orangeville is supplied with four M-Class feeders connected to the Hydro One owned Orangeville TS. Each feeder is metered with Wholesale Revenue Metering Equipment that is used for settlement in the IESO administered wholesale market and load monitoring. Also, OHL has installed Smart Faulted Circuit Indicators (FCIs) on each feeder to provide fault indication, loss of current indication and load monitoring.

The older area of the Town of Orangeville is supplied with three 4.16kV sub-stations with a total of 6 feeders. OHL monitors the peak amperage with ammeters that are read every month.

The Town of Grand Valley is supplied from a single F-Class feeder connected to the Hydro One owned Grand Valley DS. The feeder is metered with Wholesale Revenue Metering Equipment that is used for settlement in the IESO administered wholesale market and

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[5] Source: https://en.climate-data.org/north-america/canada/ontario/orangeville-10484/

[6] https://www.orangeville.ca/en/doing-business/resources/Documents/Land-Needs-Assessment-2016.pdf

[7] https://www.townofgrandvalley.ca/en/doing-business/resources/Documents/BuildingPlanningandDevelopment/PlanningandDevelopmentResourceDocuments/Official_Plan-consolidated-April-2017.pdf

load monitoring. OHL has installed FCIs on the feeder to provide fault indication, loss of current indication, and load monitoring.

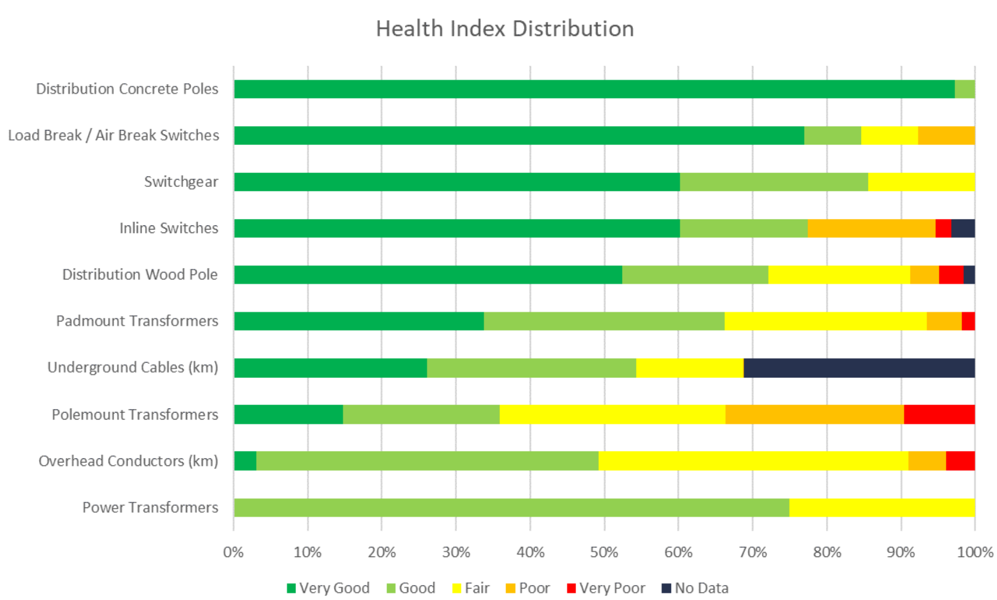
Table 5.3-5: Station Capacity and Peak Load

Station Name	Capacity	Peak Load
MS 2	5 MVA	1.2 MW
MS 3	5 MVA	1.3 MW
MS 4	5 MVA	2.0 MW
Grand Valley DS	3 MVA	2.5 MW

5.3.2.2.2 Asset Condition and Demographics

The Asset Condition Assessment ("ACA") study was carried out by METSCO in 2021 for OHL to establish the health and condition of station and distribution assets in-service. Figure 5.3-3 presents the summary results of the ACA.

Figure 5.3-3: ACA Overview



As the figure above indicates, the majority of OHL's distribution system is in Good or Better condition, with several specific asset classes containing units found to be in Poor and Very Poor condition – most notably Wood Poles and Pole Mount Transformers. Table 5.3-6 presents the numerical Health Index ("HI") summary for each asset class. The distribution of Health Indices is based on the total population count of a given asset class. For each asset class, the following details are listed: total population, average HI, average Data Availability Index ("DAI"), and the HI distribution.

Table 5.3-6: ACA Overall Results

Asset Class	Population	Health Index Distribution (%)						Average Health Index	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No Data		
Distribution Wood Pole	1691	52.40%	19.75%	19.04%	3.96%	3.31%	1.54%	83.70%	93.10%
Distribution Concrete Poles	36	97.22%	2.78%	0.00%	0.00%	0.00%	0.00%	89.06%	100.00%
Overhead Conductors (m)	73583.3	3.10%	46.10%	41.77%	5.09%	3.94%	0.00%	66.20%	100.00%
Underground Cables (m)	148163.97	26.06%	28.18%	14.50%	0.11%	0.00%	31.14%	79.40%	95.00%
Padmount Transformers	989	33.77%	32.46%	27.30%	4.65%	1.82%	0.00%	75.95%	97.86%
Polemount Transformers	345	14.78%	21.16%	30.43%	24.06%	9.57%	0.00%	60.81%	97.02%
Load Break Switches	13	76.92%	7.69%	7.69%	7.69%	0.00%	0.00%	82.42%	100.00%
Inline Switches	93	60.22%	17.20%	0.00%	17.20%	2.15%	3.23%	80.40%	53.30%
Switchgear	83	60.24%	25.30%	14.46%	0.00%	0.00%	0.00%	87.65%	99.60%
Power Transformers	4	0.00%	75.00%	25.00%	0.00%	0.00%	0.00%	76.00%	100.00%

The ACA report is found in Appendix B which contains detailed results for each asset class including demographics.

5.3.2.2.3 Asset Risks

Feeder conversion work remains a key focus of OHL's investment program throughout the forecast period. OHL is in the process of converting its 4.16 kV system to a 27.6 kV system. Throughout the conversion process, OHL will have to support the carrying cost of the legacy 4.16 kV system until fully decommissioned and removed from service.

OHL's efforts to prolong the useful life of their installed assets have led to an ageing infrastructure resulting in expected maintenance budget increases to continue delivering the expected services. In addition, older vintages of physical assets are more difficult to maintain as it is difficult to source spare parts for them. Recognizing the challenges that lie ahead, OHL continues to work upon a formal asset management program based on reliability, condition assessment and preventative and predictive maintenance practices. Understanding that replacement of large portions of the distribution system would be financially challenging, OHL has initiated several piece-wise renewal projects that can help to level the expenditures over the forecast period thereby minimizing rate impacts.

5.3.2.3 Transmission or High Voltage Assets

OHL does not own or is planning to own transmission or high voltage (>50kV) assets.

5.3.2.4 Host & Embedded Distributors

OHL's distribution system is embedded in the distribution system of Hydro One. OHL is not a host distributor. Four OHL feeders are connected to the Hydro One owned Orangeville Transformer Station and one OHL feeder is connected to the Hydro One owned Grand Valley Distribution Station.

5.3.3 Asset Lifecycle Optimization Policies and Practices

5.3.3.1 Asset Replacement and Refurbishment Policy

OHL owns all the distribution assets within its service area and is responsible for the management of all its distribution and substation assets. It maintains the efficiency and reliability of its distribution system through an active inspection, maintenance, and asset management program that focuses on customer service, employee safety, and cost-effective maintenance, refurbishment, and replacement of assets that can no longer meet utility standards.

OHL leverages practices that reflect practical and prudent business approaches for implementing the company vision and objectives. OHL uses its asset management program and capital investment process to evaluate and decide whether to replace equipment or have it repaired in addition to prioritizing the project within the overall capital program. In this it includes how OHL considers the future capacity requirements for the system and hence for specific assets. The following description of OHL's practices demonstrates OHL's consideration in the management of its assets which aid in the reliable delivery of power to its customers.

OHL considers a wide range of factors when deciding whether to refurbish or replace a distribution asset, including public and employee safety, service quality, rate impacts, maintenance costs, fault frequency, asset condition, and life expectancy so that investment in replacement plant can be prudent.

To optimize equipment value and minimize replacement costs, OHL considers the reuse of equipment from the field where safe to do so. This is done in compliance with *Ontario Regulation 22/04 (Reg. 22/04), Section 6(1) (b) – Approval of Electrical Equipment* and ensures used equipment meets current standards and poses no undue hazard for re-use in new construction. Examples of equipment subject to potential reuse are distribution transformers, load break switches and pad mount switchgear. All equipment subject to reuse must meet certain minimum condition criteria and must be deemed safe to use by a competent person. If this is the case, then the asset is returned to inventory.

If it has been determined that the asset cannot be reused but is still worth potentially repairing, then a repair estimate is obtained to return the asset to a safe and useable condition in addition to an estimate of the expected remaining useful life. If the cost of the repair plus the Net Book Value ("NBV") of the asset is less than the replacement cost and the new expected useful life exceeds the original remaining useful life, then the asset is repaired, otherwise, the asset is replaced and disposed of. Plant equipment is replaced at the end of life when all refurbishment options have been exhausted.

5.3.3.2 Description of Maintenance and Inspection Practices

Table 5.3-7: Summary of Inspection and Maintenance Activities

Assets	Category	Activity	Frequency
Overhead distribution assets	Inspections	Visual	Three-year cycle
		Infrared	One-year cycle
	Predictive maintenance	Pole testing	Periodic cycle
	Preventative maintenance	Vegetation management	Three-year cycle
Underground distribution assets	Inspections	Visual	Three-year cycle
		Infrared	One-year cycle
Station assets	Inspections	Visual	Monthly
	Predictive maintenance	Oil testing of Power Transformers	Annual

Maintenance is performed to ensure equipment continues to provide its essential functions safely over its lifecycle. Some assets require very frequent maintenance efforts (e.g., fleet vehicles), others require infrequent maintenance efforts (e.g., pole structures) and some are essentially maintenance-free (e.g., direct maintenance on a conductor). For most assets, uniform maintenance programs are established for consistency. For very large and critical assets (e.g., station transformers) maintenance programs can be unit-specific depending on the nature of asset issues discovered. All maintenance work performed meets the requirements of Reg. 22/04 and is signed off by qualified staff.

While fulfilling its asset management responsibilities, OHL engages in the following type of maintenance programs:

- Predictive Maintenance
    a. Visual Inspection - This addresses risk management and actively assesses the condition of the plant. It is also required to meet regulatory requirements.
    b. Testing - This addresses risk management and actively assesses the condition of the plant. It is more detailed and more focused than visual inspection and typically involves the measurement of some aspect of the asset. These include:
        i. Infrared inspection
        ii. Ultrasonic Partial Discharge inspection
        iii. Pole Testing
- Preventative Maintenance

a. Activities to extend the trouble-free operation of the asset so that the activity is economical and ensures the continued reliable operation of the asset. These include:

   i. Line clearing / vegetation management

   ii. Load balancing

- Condition-Based or Reactive Maintenance

   a. Occurrences where the plant is discovered to be out of specification or is malfunctioning and the condition needs to be corrected. The follow-up activities to restore the asset to full function are included here. Occasionally the most cost-effective way to remedy the situation is a replacement.

OHL completes inspections as prescribed in the DSC with an approach and frequency that addresses public safety and cost-efficiency.

The following sections are extracts from OHL's Distribution Maintenance Program which is attached under Appendix C. The results of each program will be utilized to schedule any repair work required or where appropriate capital work on a planned basis. Where the inspection/tests determine an immediate hazard to the public, immediate follow-up action will be required. Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office. The expectation is that corrective action will be completed in the year that the inspection was completed. In this way, a backlog of deficiencies will not occur.

5.3.3.2.1 Overhead Visual Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the OHL overhead system. This program covers the inspection of:

- Poles/Supports
- Overhead transformers
- Switches and Protective Devices
- Hardware and Attachments
- Conductors and Cables
- Third-party plant
- Vegetation Control

The overhead system will be fully inspected on a schedule that meets the requirements of the DSC. For this program, the "urban" population density schedule in the DSC will be utilized. On-going inspection requires the entire system to be reviewed every three years. For this program, a minimum of one-third of the overhead system will be inspected annually. This allows OHL to manage the risk lifecycle of its overhead assets.

5.3.3.2.2 Underground Visual Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro underground system. This program covers the inspection of:

- Pad-Mounted Transformers & Switching Kiosks (PME & KABAR)
- Vegetation and Right of Way

The underground system will be fully inspected on a schedule that meets the requirements of the DSC. For this program, the "urban" population density schedule in the DSC will be utilized. On-going inspection requires the entire system to be reviewed every three years. For this program, one-third of the underground system will be inspected annually. This allows OHL to manage the risk lifecycle of its underground assets.

5.3.3.2.3 Substations Visual Inspection Program

This program outlines the inspection schedule, recording and follow-up actions associated with the Orangeville Hydro substations. This program covers the inspection of:

- Distribution Substations
- Customer Specific Substations

Each substation will be inspected on a schedule that meets the requirements of the DSC. For this program, the "urban" population density schedule in the DSC will be utilized. Additional visual inspections will be completed by a contractor twice per year to assist OHL. The contractor will also take oil samples to complete Dissolved Gas Analysis and Chemical Analysis of each substation transformer.

Table 5.3-8: Substations Visual Inspection Program Schedule

Inspection Schedule			
Station Type	**Outdoor Open**	**Outdoor Enclosed**	**Indoor Enclosed**
Distribution Station	1 month	Annually	Annually
Customer Substation	Annually	3 Years	3 Years

5.3.3.2.4 Substation Preventative Maintenance

This program outlines the detailed inspection, testing, recording, and follow-up actions associated with the OHL Substation Maintenance. This program covers the:

- Testing of Substation Transformers
- Arrestor testing
- Protection Testing and Maintenance
- General station maintenance

The substations maintenance will be completed on each station once every six years.

5.3.3.2.5 Line Clearing Program

Maintaining lines free from the interference of vegetation and other obstructions is an important element to ensure the safety and reliability of the distribution system. This program outlines the inspection schedule, recording and follow-up actions associated with the OHL line clearing program. This program covers the:

- Inspection of the distribution system
- Line clearing activities

Line clearance inspections have been incorporated into the other inspection programs such as Pole Testing and Infrared Inspections, as well as, during regular work. Any areas of reduced clearance will be either resolved or noted and reported to the Manager of Operations & Engineering. Furthermore, the Zone that is scheduled for Line Clearing will be patrolled during the Clearing Activities.

Line clearing will be done as required based on inspections and reports. Maintenance work orders will be issued as a result of field observations and inspections and the work scheduled accordingly. The priority of line clearing is:

1. Primary Express Feeders (44kV and 27.6kV)
2. Fused Three Phase Circuits (27.6kV, 12.5kV, and 4.16kV)
3. Single Phase Taps (16kV, 7.2kV, and 2.4kV)
4. Roadside secondary bus
5. Rear lot construction secondary bus
6. Individual service wires

5.3.3.2.6 Load Balance Program

This program outlines the measurement, recording and follow-up actions associated with the OHL load balancing program. This program covers the:

- Recording of feeder loading
- Load balancing

The feeder loads will be measured on an annual basis. Normally this activity will be undertaken during system peak loading. If there are system issues, measurements may be taken more frequently.

If the phase loading of the various feeders is out of balance by more than 10%, work orders will be issued for the transfer of load from the higher loaded phase to the lightly loaded phase. Where loading measurements indicate that the feeder loading is reaching capacity levels, OHL will transfer the load to feeders with more capacity. Maintenance work orders will be issued to complete any load transfers.

5.3.3.2.7 Overhead and Underground Rebuilds

This program outlines the annual process for the renewal of the OHL distribution system. This program covers the:

- Recording of system inspections
- Evaluation of system rehabilitation needs
- Planned rehabilitation projects

Annual recommendations will be made for capital work on the overhead and underground systems. Recommendations will be made based on the results of the inspections throughout the year and on any special investigations completed to address specific concerns.

The expectation is to keep the general condition of the systems in good shape to prevent the need for extensive maintenance and to limit system outages due to failures. The amount of work recommended will vary depending on the conditions found in the field.

5.3.3.2.8 Infrared Inspection Program
This program outlines the inspection schedule, recording and follow-up actions associated with the OHL Infrared Program. This program covers the inspection of:

- Overhead Transformers
- Overhead Switches and Protective Devices
- Overhead Primary Conductor Splices and Terminations
- Underground Express Primary Cable Termination and Elbows
- Pad-mounted Express Switchgear Cubicles
- Secondary Bus Connections

The overhead primary system will be fully inspected on a schedule that meets the requirements of the DSC. For this program, the "urban" population density schedule in the DSC will be utilized. On-going inspection requires the entire system to be reviewed every three years. For this program, all of the overhead primary systems will be inspected annually. For this program, all express underground systems will be inspected annually.

5.3.3.2.9 Pole Testing and Inspection Program
This program outlines the inspection schedule, recording and follow-up actions associated with the OHL Pole Testing & Inspection Program. This program covers the inspection of:

- OHL Owned Poles
- Hardware and Attachments
- Third-party plant
- Vegetation Control

This program covers the testing of:

- OHL Owned Wooden Poles

OHL staff and/or a contractor will test & inspect a minimum number of poles each year. All poles will be tested before retesting poles. This will ensure no poles are missed for an extended period. It is expected that the pole testing and inspection will identify significant decay and degradation of the wood fibres. The preferred non-destructive test method is the Resistograph.

5.3.3.2.10 Pad-mounted Equipment Refinishing Program
This program outlines the schedule associated with the OHL Pad-mounted Equipment Refinishing Program. This program covers the refinishing of:

- Transformers
- Switching Cubicles (PME & KABAR)

OHL staff and/or a contractor will refinish a minimum of 20 pieces of equipment annually. It is expected that the refinishing process will remove damaged paint, remove surface rust by sanding/grinding/sand blasting, prime and paint the exterior of the equipment.

5.3.3.3 Processes and Tools to Forecast, Prioritize & Optimize System Renewal Spending

The inputs and processes for forecasting, prioritizing, and optimizing System Renewal spending are summarized in the following sub-sections. Additional information can be found in sections 5.3.1.2 and 5.3.1.3 of this DSP.

5.3.3.3.1 Forecasting

System Renewal projects are typically discretionary. The only exception in OHL's case are the meter projects with mandated service obligations through Measurement Canada. The project needs for a particular period are supported by a multitude of factors, depending on the information available for each asset type. This could include a combination of asset inspection, individual asset performance, and condition information.

An ACA study was carried out by METSCO to establish the health and condition of distribution and substation assets in service. By considering all relevant information related to the assets' operating condition, the condition of all infrastructure assets was assessed and expressed on a normalized index in the form of a HI. The HI was related to the probability of failure values for each project, using a weighted average approach, as described in detail in Appendix B, and each asset was assigned a health indicator expressed as "very good," "good," "fair," "poor," and "very poor." The resulting information from the ACA study was used to help forecast the renewal needs of OHL's assets over the forecast period. For metering projects, a combination of age, meter inspection and testing are used to forecast the meter replacements.

5.3.3.3.2 Prioritization & Optimization

OHL's optimization and prioritization process is described in section 5.3.1.3.

5.3.3.3.3 Strategies for Operating within Budget Envelopes

The proposed System Renewal projects over the forecast period were identified to maintain system reliability and were paced for implementation based on the funding available for asset renewal and by considering the resources required for project implementation for the type of work predominantly involved. Assets with the highest consequence of failure in service have been prioritized for renewal or rehabilitation during the next five years.

As OHL's planning process is continually being updated with new information, OHL completes investment planning on an annual basis to help inform any necessary budget adjustments for the following year. OHL understands that circumstances may change, and if needed, budgets can be re-prioritized depending on customer and system needs. For example, due to the nondiscretionary nature of System Access projects, these projects will take priority if there are competing demands with System Renewal projects. Completing investment planning on an annual basis allows OHL to use the best available information to effectively plan for and manage the highest priority projects and programs over the forecast period while remaining within the approved budget envelope. OHL also monitors the execution of projects against budgets and makes changes as required to stay within overall budget envelopes.

5.3.3.3.4 Risks of Proceeding / Not Proceeding

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process and is ultimately used to determine the prioritized list of capital projects and programs over the forecast period. It is at this stage of the process that OHL considered the risks associated with proceeding versus not proceeding with an individual capital expenditure and decides whether the capital expenditure is required during the forecast period or if it can be deferred.

Assets with unacceptably high-risk scores are monitored closely and plans are included in the project scope to alternatively maintain, refurbish, or replace the assets to reduce the risk to an acceptable level. It is noteworthy that some assets carry an inherently higher risk than others. The top projects in each category are identified in the prioritization process and scrutinized using further investigation and expert opinion to eliminate data inconsistencies and determine appropriate scopes of work.

5.3.3.4 Important Changes to Life Optimization Policies and Practices since Last DSP Filing

Since OHL submitted its last DSP only 2 years ago, OHL has not made any further significant changes to its life optimization policies and practices. OHL, over the next few years, will continue to review the efficacy of its process and make updates as required.

5.3.4 System Capability Assessment for REG & DERs

OHL does not have any restricted feeders currently, and as OHL is forecasting minimal DER connections in the forecast period, it has no plans to make any changes to its feeders in relation to this.

Currently, there are no REG connections for the forecast period that are already approved or in the application process. However, OHL remains vigilant in monitoring developments in the renewable energy sector. While there may not be any confirmed REG connections at present, there is still a possibility that opportunities for REG connections could arise during the forecast period.

5.3.5 CDM Activities to Address System Needs

CDM activities are aimed at reducing electricity consumption to manage system costs, reduce peak demand, and improve affordability for customers. CDM initiatives implemented by OHL under historical CDM Frameworks have resulted in some decline in peak demand, however it has not been substantial enough to avoid major infrastructure renewal projects. The IESO has not determined OHL's service area as a focus area for the Local Initiatives Program under the 2021 – 2024 Conservation and Demand Management Framework.

OHL considers CDM as part of its planning process (see section 5.3.1.3) to determine whether CDM can be considered a viable alternative to any of OHL's planned investments over the forecast period. However, no viable CDM alternatives have been identified currently. As a result, there are no CDM activities currently planned over the forecast period. OHL will continue to consider the ability to use distribution rate funded CDM to potentially defer or avoid investments. OHL will monitor the availability of new CDM programs and activities to offer our customers under future CDM Frameworks.

5.4 Capital Expenditure Plan

This section describes OHL's five-year capital expenditure plan over the forecast period, including a summary of the plan, an overview of OHL's capital expenditure planning process, an assessment of OHL's system development over the forecast period, a summary of capital expenditures, and justification of capital expenditures.

5.4.1 Capital Expenditure Summary

OHL's DSP details the program of system investment decisions developed based on information derived from OHL's asset management and capital expenditure planning process. Investments, whether identified by category or by a specific project, are justified in whole or in part by reference to specific aspects of OHL's asset management and capital expenditure planning process. OHL's DSP includes information on prospective investments over a five-year forward-looking period (2024 – 2028).

The capital expenditure summary provides a snapshot of OHL's capital expenditures over the ten-year DSP window. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories based on the primary driver for the investment:

1. System Access
2. System Renewal
3. System Service
4. General Plant

The categorization is derived from the capital expenditure planning process that prioritizes items based on whether they are discretionary or non-discretionary.

Table 5.4-1: Historical Capital Expenditures and System O&M (Part 1: 2018-2020)

Category	Historical								
	2018			2019			2020		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$		%	$		%	$		%
System Access									
Gross Capital	457,306	509,508	11%	624,306	302,685	(52%)	609,337	372,926	(39%)
Capital Contributions	(298,474)	(198,868)	(33%)	(286,252)	(114,921)	(60%)	(243,623)	(239,979)	(1%)
Net Capital	158,832	310,640	96%	338,054	187,764	(111%)	365,714	132,947	(40%)
System Renewal									
Gross Capital	33,134	201,614	508%	266,800	217,629	(18%)	189,880	394,476	108%
Capital Contributions	(0)	(0)	0%	(0)	(0)	0%	(0)	(0)	0%
Net Capital	33,134	201,614	5.08%	266,800	217,629	(18%)	189,880	394,476	108%
System Service									
Gross Capital	708,659	625,952	(12%)	535,591	676,650	26%	1,005,065	877,012	(13%)
Capital Contributions	(0)	(0)	0%	(0)	(0)	0%	(0)	(0)	0%
Net Capital	708,659	625,952	(12%)	535,591	676,650	26%	1,005,065	877,012	(13%)
General Plant									
Gross Capital	152,500	450,696	196%	315,800	171,264	(46%)	424,000	280,525	(34%)
Capital Contributions	(0)	(6,844)	0%	(0)	(0)	0%	(0)	(0)	0%
Net Capital	152,500	443,852	191%	315,800	171,264	(46%)	424,000	280,525	(34%)
Total (Gross)	1,351,599	1,780,926	32%	1,742,497	1,368,228	(21%)	2,228,282	1,924,939	(14%)
Total Capital Contributions	(298,474)	(198,868)	(33%)	(286,252)	(114,921)	(60%)	(243,623)	(239,979)	(1%)
Total (Net)	1,053,125	1,582,058	50%	1,456,245	1,253,307	(14%)	1,984,659	1,684,960	(15%)
System O&M	1,193,236	754,878	(37%)	1,001,431	958,991	(4%)	1,001,995	807,988	(19%)

Table 5.4-2: Historical Capital Expenditures and System O&M (Part 2: 2021-2023)

Category	Historical						Bridge		
	2021			2022			2023		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$		%	$		%	$		%
System Access									
Gross Capital	315,167	736,527	134%	427,898	96,413	(77%)	820,036	820,036	0%
Capital Contributions	(204,526)	(349,139)	71%	(203,055)	(62,566)	(69%)	(451,067)	(451,067)	0%
Net Capital	110,641	387,388	204%	224,843	33,847	(147%)	368,969	368,969	0%
System Renewal									
Gross Capital	790,484	530,019	(33%)	541,020	554,050	2%	583,184	583,184	0.00
Capital Contributions	(0)	(0)	0%	(0)	(0)	0%	(0)	(0)	0%
Net Capital	790,484	530,019	(33%)	541,020	554,050	2%	583,184	583,184	0.00
System Service									
Gross Capital	867,598	925,386	7%	1,095,187	2,197,624	101%	976,919	976,919	0.00
Capital Contributions	(0)	(0)	0%	(0)	(0)	0%	(0)	(0)	0%
Net Capital	867,598	925,386	7%	1,095,187	2,197,624	101%	976,919	976,919	0.00
General Plant									
Gross Capital	101,880	66,192	(35%)	213,100	134,922	(37%)	124,383	124,383	0.00
Capital Contributions	(0)	(0)	0%	(0)	(0)	0%	(0)	(0)	0%
Net Capital	101,880	66,192	(35%)	213,100	134,922	(37%)	124,383	124,383	0.00
Total (Gross)	2,075,129	2,258,124	9%	2,277,206	2,983,009	31%	2,504,522	2,504,522	0.00
Total Capital Contributions	(204,526)	(349,139)	71%	(203,055)	(62,566)	(69%)	(451,067)	(451,067)	0.00
Total (Net)	1,870,603	1,908,986	2%	2,074,151	2,920,443	41%	2,053,455	2,053,455	0.00
System O&M	1,111,995	1,077,960	(3%)	1,134,235	1,164,462	3%	1,249,459	1,249,459	0.00

The following table summarizes the planned capital expenditures, by investment category, throughout the DSP forecast timeline.

Table 5.4-3: Forecast Capital Expenditures and System O&M

Category	Forecast				
	2024	2025	2026	2027	2028
	$	$	$	$	$
System Access					
Gross Capital Spend	1,359,889	658,682	688,513	650,310	865,968
Capital Contributions	(718,936)	(203,666)	(377,697)	(291,859)	(372,702)
Net Capital Expenditures	640,953	455,016	310,816	358,451	493,266
System Renewal					
Gross Capital Spend	787,454	720,928	816,933	737,671	807,351
Capital Contributions	(0)	(0)	(0)	(0)	(0)
Net Capital Expenditures	787,454	720,928	816,933	737,671	807,351
System Service					
Gross Capital Spend	818,940	1,194,177	1,405,127	1,359,250	1,557,016
Capital Contributions	(0)	(0)	(0)	(0)	(0)
Net Capital Expenditures	818,940	1,194,177	1,405,127	1,359,250	1,557,016
General Plant					
Gross Capital Spend	710,917	436,000	215,000	490,000	225,000
Capital Contributions	(0)	(0)	(0)	(0)	(0)
Net Capital Expenditures	710,917	436,000	215,000	490,000	225,000
Total Expenditure, Gross	$3,677,200	$3,009,787	$3,125,573	$3,237,231	$3,455,335
Total Capital Contribution	($718,936)	($203,666)	($377,697)	($291,859)	($372,702)
Total Expenditure, Net	$2,958,264	$2,806,121	$2,747,876	$2,945,372	$3,082,633
System O&M	1,359,282	1,393,264	1,379,096	1,169,562	1,198,802

5.4.1.1 Plan vs Actual Variances for the Historical Period

Assessing and understanding the variances is an important step for OHL to promote continuous improvements in its estimation and budgeting process. Excluding projects identified as mandatory, OHL 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 reviewed monthly. 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 (i.e., OHL 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 budget of System Access projects is less than the forecasted budget, OHL may plan to allocate the budget to other System Access planning years or to other project categories where appropriate to maintain consistent annual expenditures. OHL is identifying in advance that some variances are significantly high in some years for a few categories.

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 primary and secondary service requests. No sub-category can be planned for with a high degree of accuracy. However, OHL attempts to minimize the variances with proactive engagements with developers, city departments and customers. OHL is often aware of future proposed subdivisions and road relocation projects, but development can often be slow, and projects may remain in the preliminary stages for many years before implementation which is beyond OHL's control.

System Renewal

System Renewal variances were attributed to higher or lower unit replacements than originally budgeted. As OHL progresses through its risk management tasks and lifecycle activities, OHL can identify the most at-risk assets that should be replaced to maintain system performance. Additionally, on completion of the maintenance tasks, if the asset does not need to be replaced, OHL would not replace the asset to meet the planned budget. This is a benefit to its customers so that the bill impacts, and increases are minimized as much as possible. Annual variances were attributed due to project deferrals each year due to the more than anticipated customer requests and System Access projects in 2014. However, OHL has been able to achieve its capital plan presented in the previous DSPs.

System Service

The historical System Service variances were contributed to the voltage conversion project delays in 2014/2015 which had a cascading effect on the current year with project scopes being shifted by a year each year. The primary reasons for the delays include weather and higher priorities for emergencies, reactive and System Access work with a limited resource pool from OHL to complete the expected work each year.

General Plant

General Plant projects are identified internally by specific departments (IT, finance, engineering, operations, customer service, and administration), OHL prioritizes the investments most needed to maintain reliable operations for the business and its customers.

OHL's 2014 DSP covered a forecast period of 2014 to 2018. For 2019 to 2022 OHL used its own Board-Approved capital budget as a comparative for material variances over $10,000.

DSP Planned vs Actual Expenditures for 2018 to 2022 Period

Table 5.4-1 provides OHL's historical capital expenditures. OHL's 2014 DSP ended in 2019. The Planned comparisons then become the OHL Business Plan approved by its Board of Directors.

Overall, OHL has met its targets in meeting its planned target on an average of the last 5 years, 2018 to 2022. Most of the 11% variance can be attributed to the 2022 fiscal year, which was caused by increased material cost and a large fiber project where it was beneficial for OHL to bury duct jointly with the fiber company.

Table 5.4-4: Average Net Historical Capital Expenditures Summary

Category	5-Year Plan Average	5-Year Actuals Average	Variance
	$ '000		%
System Access	240	211	(12)
System Renewal	364	380	4
System Service	843	1,061	26
General Plant	242	222	(8)
Total Expenditure, Net	1,688	1,873	11

Table 5.4-5: Variance Explanations - 2018 Planned Versus Actuals

Category	2018 Plan. $	2018 Act. $	2018 Var. $	2018 Var. %	Variance Explanations
System Access, Gross	457,306	509,508	52,202	11%	Subdivision expansions in OHL service territory were higher by $200K. These subdivisions are non-discretionary, and the timelines are driven by the developers, the execution of the Offer to Connect and energization of the subdivision. In 2018, 4 subdivisions were energized whereas typically OHL will plan to energize 2 or 3 in a year or connect about 100 new customers.
System Renewal, Gross	33,134	201,614	168,480	508%	OHL purchased 560 meters for $125K during the year in anticipation of residential meter reverification project. 18 pole replacements were done as well. OHL had not planned for these expenditures at all during the 2014 DSP.
System Service, Gross	708,659	625,952	(82,707)	(12%)	The $635K Robb Boulevard and the $74K C-Line & Century Drive conversions which were planned were delayed to 2020 and 2021. During 2018, the Ms4-E Feeder Voltage Conversion was completed for $546K (originally planned for 2017). The Riddell Road feeder tie (originally planned in 2014) was started for $43K and continued into 2019.
General Plant, Gross	152,500	443,852	291,352	191%	OHL purchased a Freightliner single bucket for $300K which had been delayed since the 2015 DSP year, as OHL had some discretion as to the state of the aerial device.
Total Gross Capital Expenditure	**1,351,599**	**1,780,926**	**429,327**	**32%**	The primary drivers for the increase were a substantial increase in general plant, system renewal and system access, offset by decreased spending in system service.
Capital Contributions	**(298,474)**	**(198,868)**	**99,606**	**(33%)**	Lower Capital Contributions due to less contributed capital from subdivision energizations.
Net Capital Expenditures	**1,053,125**	**1,582,058**	**528,933**	**50%**	The primary drivers for the increase were a substantial increase in general plant, system renewal and

Category	2018 Plan. $	2018 Act. $	2018 Var. $	2018 Var. %	Variance Explanations
					system access, offset by decreased spending in system service.

Table 5.4-6: Variance Explanations - 2019 Planned Versus Actuals

Category	2019 Plan. $	2019 Act. $	2019 Var. $	2019 Var. %	Variance Explanations
System Access, Gross	624,306	302,685	(321,621)	(52%)	Subdivision expansions in OHL service territory were lower by $150K. These subdivisions are non-discretionary, and the timelines are driven by the developers, the execution of the Offer to Connect and energization of the subdivision. In 2019, 3 small subdivisions were energized.
System Renewal, Gross	266,800	217,629	(49,171)	(18%)	OHL replaced only 1 pole in 2019. (-$52K)
System Service, Gross	535,591	676,650	141,059	26%	OHL had not planned on doing the Riddell Rd feeder tie which had been planned in 2014 in the previous DSP.
General Plant, Gross	315,800	171,264	(144,536)	(46%)	OHL had planned for billing and accounting system enhancements ($107K) which did not materialize. The purchase of a replacement for a 2008 Dodge Caravan was deferred into a future year.
Total Gross Capital Expenditure	**1,742,497**	**1,368,228**	**(374,269)**	**(21%)**	The primary drivers for the decrease were a decrease in system access, general plant, and system renewal, offset by increased spending in system service.
Capital Contributions	**(286,252)**	**(114,921)**	**171,331**	**(60%)**	Lower Capital Contributions due to less subdivision energization and customer-driven requests.
Net Capital Expenditures	**1,456,245**	**1,253,307**	**(202,938)**	**(14%)**	The primary drivers for the decrease were a decrease in system access, general plant, and system renewal, offset by increased spending in system service.

Table 5.4-7: Variance Explanations - 2020 Planned Versus Actuals

Category	2020 Plan. $	2020 Act. $	2020 Var. $	2020 Var. %	Variance Explanations
System Access, Gross	609,337	372,925	(236,412)	(39%)	Subdivision expansions in OHL service territory were lower by $150K. These subdivisions are non-discretionary, and the timelines are driven by the developers, the execution of the Offer to Connect and energization of the subdivision. Mayberry Hills Phase 3A ($260K) was not energized during the year, which was offset by Cachet Grand Valley Phase being energized sooner than anticipated.
System Renewal, Gross	189,880	394,476	204,596	108%	OHL replaced 14 failed transformers, whereas OHL usually plans for about 10 transformers being defective, as well as purchasing new transformers for 2021 projects (213K). Only 4 pole replacements were done in 2020. (-$30K)
System Service, Gross	1,005,065	877,012	(128,053)	(13%)	The $509K Third St/Second St conversion from the 2015 DSP was done from 2019 on and was finally completed in 2021. Due to re-prioritization of projects, the Robb Boulevard conversion could not proceed as planned (-$568K).
General Plant, Gross	424,000	280,525	(143,475)	(34%)	OHL postponed a number of general plants purchased due to the pandemic, as most of those are discretionary in nature.
Total Gross Capital Expenditure	**2,228,282**	**1,924,938**	**(303,344)**	**(14%)**	The primary drivers for the decrease were a decrease in system access, general plant, and system service, offset by increased spending in system renewal.
Capital Contributions	**(243,623)**	**(239,979)**	**3,644**	**(1%)**	N/A
Net Capital Expenditures	**1,984,659**	**1,684,959**	**(299,700)**	**(15%)**	The primary drivers for the decrease were a decrease in system access, general plant, and system service, offset by increased spending in system renewal.

Table 5.4-8: Variance Explanations - 2021 Planned Versus Actuals

Category	2021 Plan. $	2021 Act. $	2021 Var. $	2021 Var. %	Variance Explanations
System Access, Gross	315,167	736,528	421,361	134%	Subdivision expansions in OHL service territory were higher by $425K. These subdivisions are non-discretionary, and the timelines are driven by the developers, the execution of the Offer to Connect and energization of the subdivision. Mayberry Hills Phase 3A ($437K) was energized during the year, although OHL had not forecast for it to be energized.
System Renewal, Gross	790,484	530,019	(260,465)	(33%)	OHL replaced 14 defective transformers, whereas we usually plan for about 10 transformers being defective, as well as installing existing stock transformers on various projects ($210K). OHL did 21 pole replacements though 28 were planned (-$64K). Delays on transformer delays also contributed to this.
System Service, Gross	867,598	925,386	57,788	7%	MS2-West Feeder conversion was done for $50K more due to lines contract planned at a higher estimated than actual costs.
General Plant, Gross	101,880	66,192	(35,688)	(35%)	OHL had $20K less of general plant purchases due to a planned front office washroom renovation that was postponed to 2021.
Total Gross Capital Expenditure	**2,075,129**	**2,258,125**	**182,995**	**9%**	The primary drivers for the increase were an increase in system access and system service, offset by decreased spending in system renewal and general plant.
Capital Contributions	**(204,526)**	**(349,139)**	**(144,613)**	**71%**	Higher Capital Contributions due to more contributed capital from subdivision energizations.
Net Capital Expenditures	**1,870,603**	**1,908,986**	**38,383**	**2%**	The primary drivers for the increase were an increase in system access and system service, offset by decreased spending in system renewal and general plant.

Table 5.4-9: Variance Explanations - 2022 Planned Versus Budget

Category	2022 Plan. $	2022 Act. $	2022 Var. $	2022 Var. %	Variance Explanations
System Access, Gross	427,898	96,415	(331,483)	(77%)	Subdivision expansions in OHL service territory were lower by $191K. These subdivisions are non-discretionary, and the timelines are driven by the developers, the execution of the Offer to Connect and energization of the subdivision. Mayberry Hills Phase 3A was planned to be energized in 2022, but Mayberry Hills was energized in 2021 and the First St Towns were energized in 2023.
System Renewal, Gross	541,020	554,050	13,030	2%	OHL replaced 2 failed transformers, whereas we usually plan for about 10 defective transformers, as well as purchasing stock transformer for future projects. OHL did 19 pole replacements though 17 were planned (-$26K).
System Service, Gross	1,095,187	2,197,624	1,102,437	101%	MS2-South Feeder conversion was done for $221K more than planned due to increased material and contractor costs caused by projects being brought forward from future years. MS-2 South Feeder conversion expanded to two new areas: Edelwild/Avonmore/Johanna and Edelwild/Rustic/Cedar/Lawrence. These were large fiber project where it was beneficial for OHL to bury duct jointly with the fiber company. These last 2 caused unplanned jobs cost of $492K and $596K.
General Plant, Gross	213,100	134,922	(78,178)	(37%)	OHL postponed Silverblaze and mCare software purchases ($49K).
Total Gross Capital Expenditure	**2,277,206**	**2,983,011**	**705,805**	**31%**	The primary drivers for the increase were an increase in system service and system renewal, offset by decreased spending in system access and general plant.
Capital Contributions	**(203,055)**	**(62,566)**	**140,489**	**(69%)**	Lower Capital Contributions due to less subdivisions and customer-driven requests.
Net Capital Expenditures	**2,074,151**	**2,920,445**	**846,294**	**41%**	The primary drivers for the increase were an increase in system service

Category	2022				Variance Explanations
	Plan.	Act.	Var.	Var.	
	$		%		
					and system renewal, offset by decreased spending in system access and general plant.

2023 Variance Summary

As 2023 is still ongoing, no variance analysis has been carried out.

5.4.1.2 Forecast Expenditures

Figure 5.4-1 below outlines the planned forecast expenditures by individual investment categories.

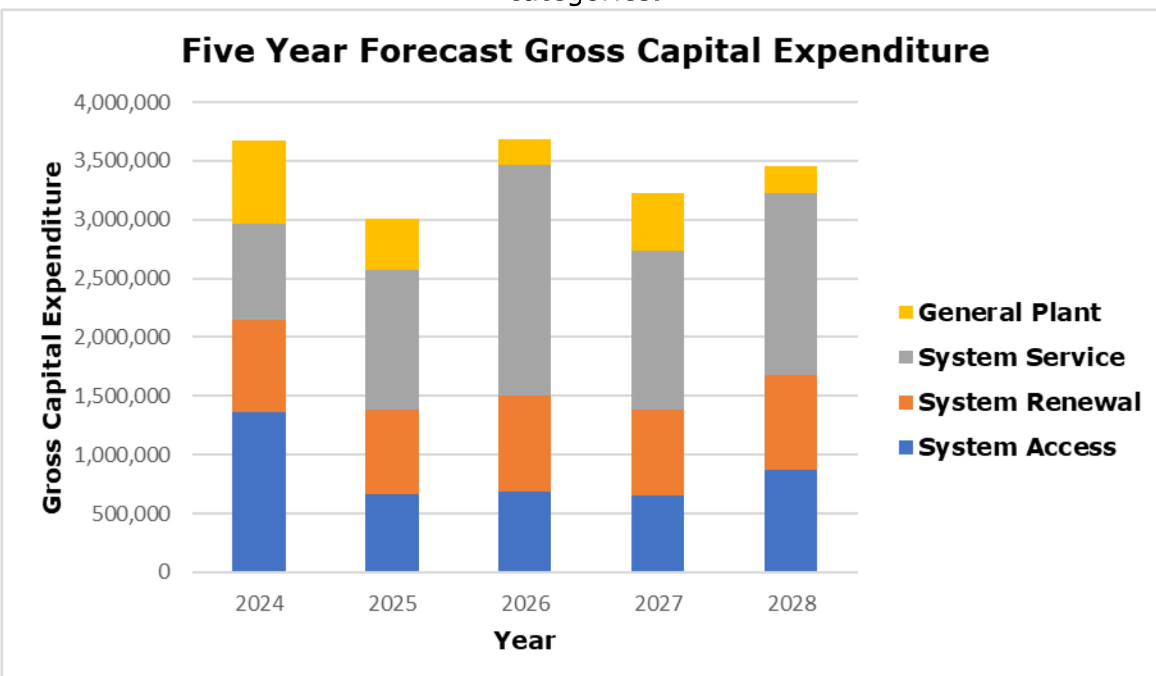


Figure 5.4-1: Planned capital expenditures by investment category

OHL has developed a prudent capital budgeting process combined with a system of capital project prioritization that considers customer preferences, business performance and accountability. This system reflects its long-term strategy and addresses the need for OHL to remain flexible enough to respond to priority shifts as they occur. The capital budget process considers the relative priorities of the proposed investments including both non-discretionary and discretionary budget items.

Non-Discretionary items include:

- Projects that accommodate the company's obligation to connect including new customers as well as load growth.
- Projects to accommodate municipal, regional and Ministry requirements.
- Projects or expenditures to satisfy regulatory initiatives, environmental or health & safety risks and the company's conditions of service.

Discretionary Items include:

- Infrastructure Renewal Projects
- Information Technology
- Fleet/Tools

The combination of OHL's asset management and capital expenditure planning process leads to a capital expenditure plan consisting of a five-year capital expenditure forecast which includes a one-year detailed capital budget.

5.4.1.2.1 System Access

Expenditures in this category are driven by external requirements such as servicing new customer loads and relocating distribution plants to suit road authorities. The timing of investment is driven by the needs of the external parties. These expenditures are mandatory. Specific project scopes are rarely known at the time that the budget is set, and total expenditures can vary from year to year. Most of the forecasted investments in this category are based on historical requirements. Specific projects such as relocations are budgeted based on OHL's estimates and historical averages, in conjunction with information from external agencies of the work required over the project life cycle. OHL's proposed 2024 – 2028 System Access forecast investments are found in the table below.

System Access investments consist of the following major items: customer connections and new services. Customer connections include connecting existing customers to the system specifically those that are affected by the voltage conversion efforts. New services include supplying electrical equipment and materials to residential, commercial, and industrial accounts where no electrical supply currently exists.

The increase in 2024 is driven by two larger than the historical average subdivisions. Edgewood Valley Developments Phase 2B is a detached home development which is much larger than OHL's typical subdivision connection projects. Another Grand Valley single detached home development is expected to be energized and has been confirmed to OHL by the developers. During this capex planning process, OHL reached out to the subdivision developers, and they have confirmed energization in 2024.

Table 5.4-10: Forecast Net System Access Expenditures

Category	Forecast					Total ($)	Percent of Total
	2024	2025	2026	2027	2028		
	$						
Various General Service Capital Contribution Projects	40,000	40,000	40,000	40,000	40,000	200,000	9%
Various Residential Capital Contribution Projects	5,000	5,000	5,000	5,000	5,000	25,000	1%
Estimated Distributed Energy Resources	0	0	0	0	0	0	0%
Various Subdivisions	595,953	410,016	265,816	313,451	448,266	2,033,501	90%
Total Expenditure, Net	640,953	455,016	310,816	358,451	493,266	2,258,501	100%

5.4.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and play a crucial role in the overall reliability, safety, and sustainment of the distribution system. OHL's ACA recommends assets for renewal based on condition data from tests and inspections. The asset management process outlines the strategy used to determine the criteria for asset replacement. The output of the asset management process drives the development of the capital expenditure plan and prioritization for System Renewal. OHL's proposed 2024 – 2028 System Renewal forecast investments are found in the table below.

As part of the asset renewal projects, OHL plans to replace overhead and underground assets which exhibit signs of deterioration consistent with End-of-Life ("EOL") criteria as defined by the utility's asset management standards. These investments are aimed at maintaining the safety and reliability of the distribution system while mitigating the cost impacts to customers. OHL focuses on replacing wooden poles, transformers and hardware which exhibit signs of deterioration consistent with EOL criteria as defined by the utility's asset management standards. For example, deteriorated poles that lose their structural integrity pose a safety risk to the employees servicing them and the public. Moreover, in-field failures of deteriorated assets can affect system reliability performance, potentially resulting in outages that would be longer and can cost more under a reactive replacement than under a proactive replacement approach.

The increase in 2024 is driven by a sleeve replacement program and the higher cost of materials. This program is designed to remove the automatic tension sleeves from the primary distribution system to be replaced with compression sleeves. The need for this program was identified after the December 2022 blizzard which triggered OHL to file a major event report with the OEB.

During the planning process, OHL increased meter purchases in 2024, 2025, 2026, 2027, and 2028 to replace existing meters and to connect new customers. The whole meter population requires replacement or reverification by 2028. OHL is pacing its meter programs to minimize any one-off impacts. The forecasted quantities for purchase are: 1,202 in 2024, 1,424 in 2025, 1,656 in 2026, 1,424 in 2027, and 1,712 in 2028. These purchases will be used for new installations, to replace failed existing meters, and to begin a paced renewal program for existing smart meters.

Table 5.4-11: Forecast Net System Renewal Expenditures

Category	Forecast					Total ($)	Percent of Total
	2024	2025	2026	2027	2028		
	$						
Substation Renewal	7,194	0	7,194	0	7,194	21,582	1%
Failed Transformer/PME Replacement	161,383	161,383	161,383	161,383	161,383	806,915	21%
Hardware Replacement	227,478	50,000	50,000	50,000	50,000	427,478	11%
Meter Replacement and Additions – Purchases, Sampling, Reverification,	243,499	361,645	450,456	378,388	440,874	1,874,862	48%

Category	Forecast 2024	2025	2026	2027	2028	Total ($)	Percent of Total
	$						
Phone to Modem, Replacement							
Pole Replacement	147,900	147,900	147,900	147,900	147,900	739,500	19%
Total Expenditure, Net	787,454	720,928	816,933	737,671	807,351	3,870,337	100%

5.4.1.2.3 System Service

Expenditures in this category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and DER integration) while addressing anticipated future customer electricity service requirements (i.e., station capacity increases, feeder extension, etc.). OHL's proposed 2024 – 2028 System Service forecast investments are found in the table below. OHL plans to continue its ongoing voltage conversion effort on its system over the forecast period.

In the forecast period, the primary reason for the increase in System Service budgets is OHL is planning the steady continuation of the 4kV voltage conversion circuits. Most of the 4kV assets remaining are underground cable and pad-mounted transformers, in which underground infrastructure costs more to replace than the overhead infrastructure.

Table 5.4-12: Forecast Net System Service Expenditures

Category	Forecast 2024	2025	2026	2027	2028	Total ($)	Percent of Total
	$						
Voltage Conversion Project #1	419,902	206,345	882,704	805,985	663,065	2,978,001	47%
Voltage Conversion Project #2	209,941	577,878	522,423	553,265	537,323	2,400,831	38%
Voltage Conversion Project #3	189,097	409,955	0	0	356,627	955,678	15%
Total Expenditure, Net	818,940	1,194,177	1,405,127	1,359,250	1,557,016	6,334,510	100%

5.4.1.2.4 General Plant

Expenditures in this category are driven by the need to modify, replace or add to assets that are not part of the distribution system but support the utility's everyday operations (i.e., land, buildings, tools, and equipment; rolling stock and electronic devices and software used to support day to day business and operations activities). While these items are important and contribute to a safe and reliable operation, General Plant investment levels and timing are generally subject to a greater degree of discretion than other investment categories. However, if ignored over a significant period, it may result in larger issues and investments needed without any discretion to continue daily operations. OHL's proposed 2024 – 2028 General Plant forecast investments are found in the table below.

The 2024 expenditures are due to a much-needed roof replacement, a new industry standard of GIS, a financial software upgrade and an enhanced customer portal. OHL's building was built in 1990 and the roof is beyond its life expectancy. OHL was informed by a third party that it is in serious need of replacement. OHL's existing customer portal is no longer being supported and is increasing cybersecurity concerns. It also provides customers with poor customer experience when they attempt to manage their accounts online.

Table 5.4-13: Forecast Net General Plant Expenditures

Category	Forecast					Total ($)	Percent of Total
	2024	2025	2026	2027	2028		
	$						
Building	296,000	200,000	50,000	20,000	50,000	616,000	30%
Office Equipment	30,000	18,000	3,000	13,000	13,000	77,000	4%
Computer Equipment	58,000	27,000	16,000	16,000	16,000	133,000	6%
Computer Software	197,380	107,000	32,000	32,000	32,000	400,380	19%
Vehicles	93,815	70,000	100,000	395,000	100,000	758,815	37%
Stores Equipment	2,000	2,000	2,000	2,000	2,000	10,000	0%
Tools, Shop & Garage Equipment	6,500	7,000	7,000	7,000	7,000	34,500	2%
Measurement & Testing	24,222	2,000	2,000	2,000	2,000	32,222	2%
Miscellaneous Equipment	2,000	2,000	2,000	2,000	2,000	10,000	0%
Land Rights	0	0	0	0	0	-	0%
Communication Equipment	1,000	1,000	1,000	1,000	1,000	5,000	0%
Total Expenditure, Net	710,917	436,000	215,000	490,000	225,000	2,076,917	100%

It should be noted that OHL was GreenButton certified in May 2023. The testing & implementation continues with their vendor/provider. OHL expects to go-live in October 2023.

5.4.1.2.5 Investments with Project Lifecycle Greater than One Year

OHL forecasts that the equipment installed under the forecasted projects will be in-service at year end and the costs will be a capitalized in the year of installation. In the event that a project does span over multiple years, OHL followed and will continue to follow the OEB's accounting processes and use account 2055 – Work in Progress.

5.4.1.3 Comparison of Forecast and Historical Expenditures

OHL has previously stated its objective is to meet all regulated requirements and manage its assets in a manner that minimizes the cost to OHL customers and ratepayers. OHL delivers value to customers by controlling costs concerning its proposed investments through appropriate optimization prioritization and pacing of capital-related expenditures.

With this objective in mind, OHL has been carefully examining and monitoring its distribution system through the historical period in addition to understanding industry trends and practices to identify appropriate technologies and opportunities for integration. Based on the condition assessments that have been performed, it is evident that OHL's asset base is ageing and requires maintenance, refurbishment, and potential replacement of assets in a timely, planned, and controlled manner. Although OHL can extend the life of its in-service assets, this does not preclude it from having a plan and performing asset maintenance to maintain the high level of reliability demanded by its customers.

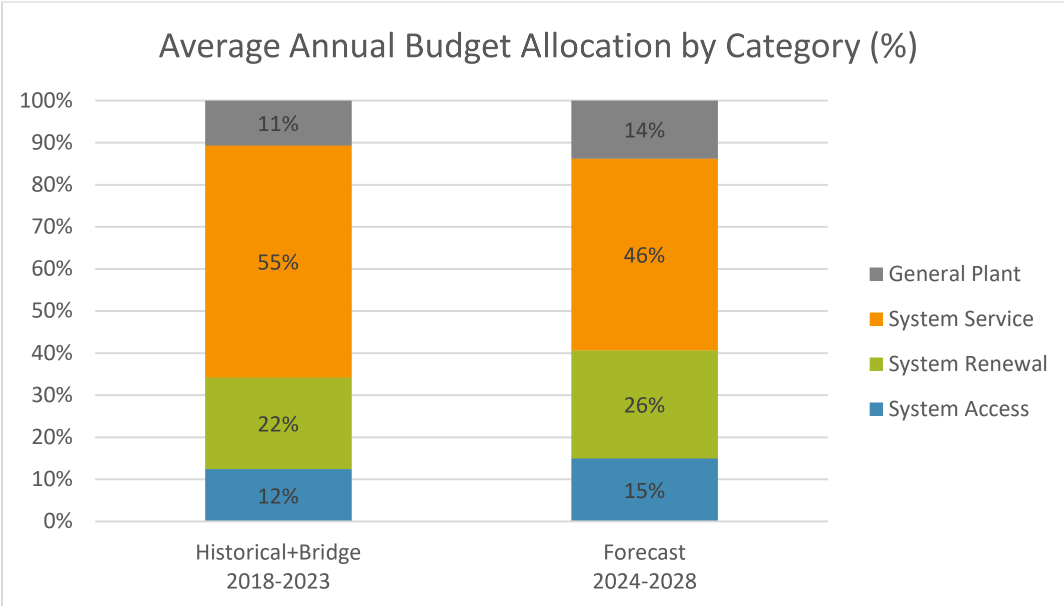
Continuing to operate and maintain the existing system indefinitely would mean a progressively more expensive maintenance program with increasing difficulty in finding parts with the risk of failing equipment due to age and service life. Furthermore, continuing without a planned and controlled maintenance program could result in diminished reliability standards and progressively more incidents resulting in potential hazards to both staff and the public. Operating the system without performing maintenance would result in an inability to meet customer needs and expectations.

The alternative to this is the path chosen by OHL which is currently being implemented and involves the measured, strategic, and planned upgrade, replacement, and refurbishment of the electrical distribution system. As a prudent utility, OHL has realized the costs of this action would be prohibitive if considered in a single year. Consequently, OHL has developed its current plan to maintain customer-driven reliability while eliminating lumpy investments and volatile rate impacts. Pursuing this path through the forecast period and beyond can ultimately reduce overall operating and maintenance costs by eliminating the 4.16 kV MS's and simultaneously enabling the system capacity to accept distributed generation and additional load. This conversion to 27.6 kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16 kV substations, enhanced public safety through the relocation of utility plant from backyards to public rights of way and the satisfaction of customer expectation for a system with high-reliability standards.

5.4.1.3.1 Overall Capital Expenditures

A comparison can be made of OHL's annual budget allocation between the historical period and the forecast period, shown in Figure 5.4-2. OHL wants to increase forecast expenditures for System Service projects while also maintaining its system where needed without significant bill impacts to the customer. The primary reason for the increase in System Service budgets is the continuation of the 4kV voltage conversion circuits. However, most of the assets remaining are underground cable and pad-mounted transformers, in which underground infrastructure costs more to replace than the overhead infrastructure. In some of the past years, OHL had been focusing on overhead assets with minimal budget and resources being directed onto underground assets. Moving forward, the reverse effect will be seen with a higher focus of budget and resources on underground assets versus overhead assets. In addition, due to the uncertainty associated with System Access projects, if the budget does not get used within the planning year, OHL intends on diverting the funds to other needed investments where appropriate to achieve OHL's objectives in addition to meeting the customer's expectation of the system's performance.

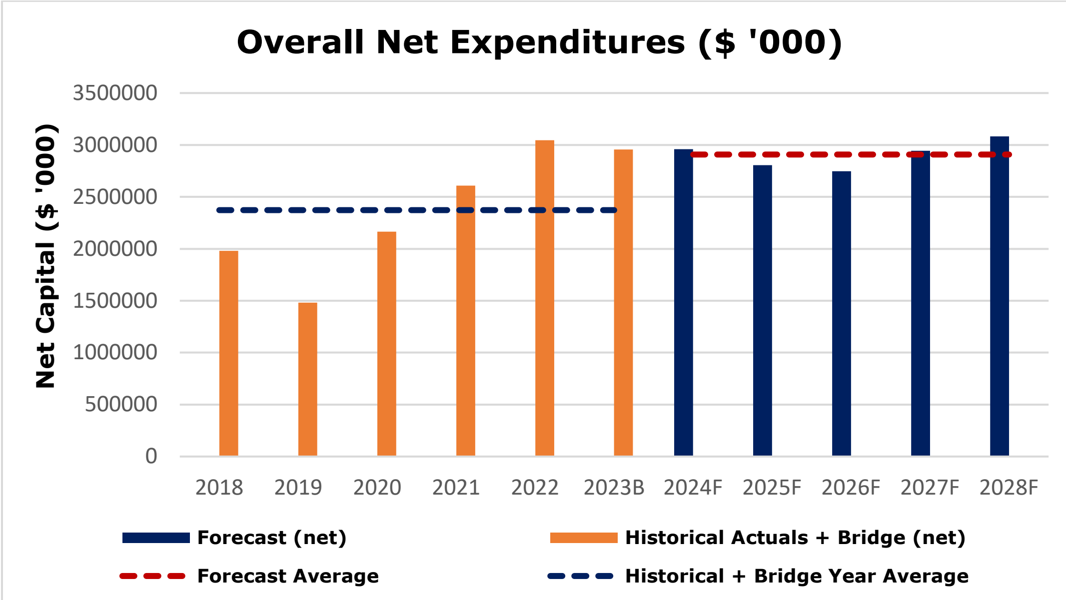
Figure 5.4-2: Average Annual Budget Allocation (Historical vs. Forecast)



The overall gross capital expenditure trend over the 2018 to 2028 period, is shown in. The average overall gross capital expenditures forecast is approximately 51% higher than the historical plus bridge-year average. This is largely as a result of the following factors:

- Uptake in System Access projects in 2024 identified by the town and developers that require energization during the forecast period.
- Increases in supply chain, labour, and material costs.
- Increase in System Renewal costs, to deliver a more consistent level of spending to ensure OHL is able to maintain its system reliability.
- Increase in System Renewal costs to begin renewing meter population.
- General Plant increases in 2024 due to an urgent need to replace the roof of OHL's office building to ensure the safety of its employees.
- Introduction of new programs to pro-actively address issues identified during the historical period.

Figure 5.4-3: Overall Gross Capital Expenditures



OHL has developed a prudent capital budgeting process combined with a system of capital project prioritization that considers customer preferences, business performance and accountability. OHL's investment plan reflects its long-term strategy and addresses the need for OHL to remain flexible enough to respond to priority shifts as they occur. The capital budget process considers the relative priorities of the proposed investments including both non-discretionary and discretionary budget items.

Non-Discretionary items include:

- Projects that accommodate the company's obligation to connect including new customers as well as load growth.
- Projects to accommodate municipal, regional and Ministry requirements.
- Projects or expenditures to satisfy regulatory initiatives, environmental or health & safety risks and the company's conditions of service.

Discretionary Items include:

- Infrastructure Renewal Projects
- Information Technology
- Fleet/Tools

OHL's investment plan will enable them to achieve its corporate and AM objectives of:

- Safety – projects that are considered to address safety as a primary factor.
- Reliability & Performance – projects that help OHL maintain or improve its reliability and meet other OEB performance measures.
- Asset Condition – projects that address assets that are at risk of failure as identified through both asset condition assessments, and inspection and maintenance information.
- Customer Focus – projects that enable OHL to address customer priorities and continue to deliver excellent service to its customers.
- Best Practice – projects that enable OHL to address assets that are no longer considered best practice and are impacting OHL's performance.

5.4.1.3.2 System Access

System Access investments include the following drivers:

- Customer service requests - continued development of the Town of Orangeville and the Town of Grand Valley requiring new customer connections (site redevelopment; subdivisions).

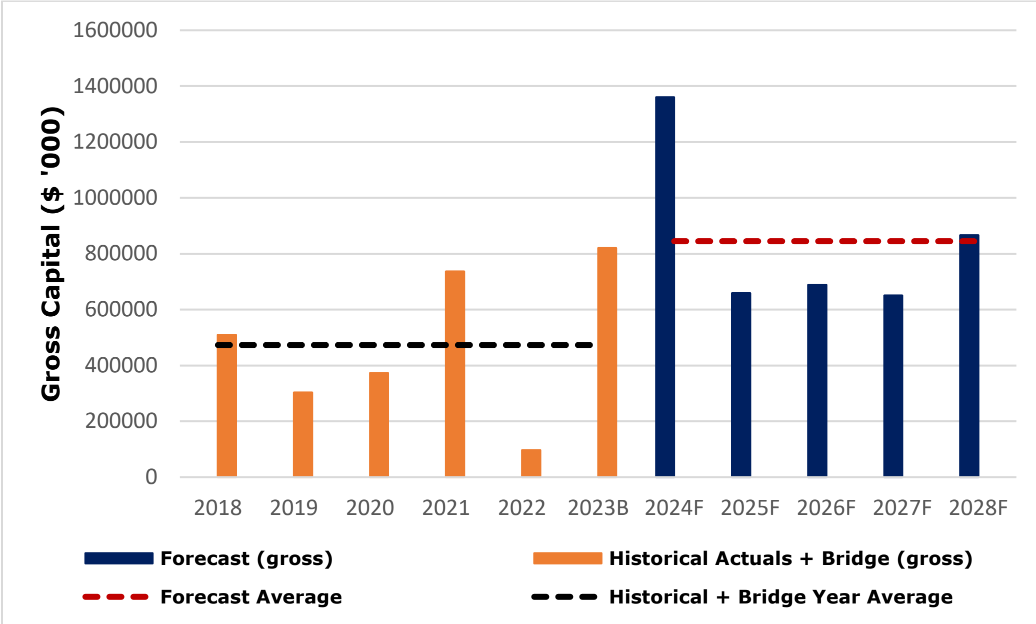
The historical trend with System Access was significantly variable year over year due to variability of new subdivisions development. As shown in Figure 5.4-4 the forecast average is 79% higher than the historical average. This is based on the projections Orangeville currently has for the town as well as historical performance trends concerning customer connections. The subdivision developments within the historical years consisted mostly of infill townhouse developments. The forecast period consists of both infill townhouse developments and lager developments consisting of a mix of single detached homes and townhouses. OHL believes the proposed budget has adequate resources and funds in place to accommodate potential future connections and projects that are deemed mandatory. However, these projects are difficult to forecast with high accuracy and may still change as these are dependent on developers and city plans. For 2024, the individual developers have confirmed they still plan to proceed with their projects, namely Mayberry Hills Phase 3B, Edgewood Valley and Cachet Main Street North.

Table 5.4-14: Planned Number of Subdivisions and New Connections

Year	Number of Subdivisions	Number of New Connections
2024	3	281
2025	2	145
2026	2	117
2027	1	193
2028	2	219

The above table shows the forecasted number of developments and forecasted number of new connections within the development.

Figure 5.4-4: Comparative Gross Expenditures for System Access



5.4.1.3.3 System Renewal

System Renewal investments include the following drivers:

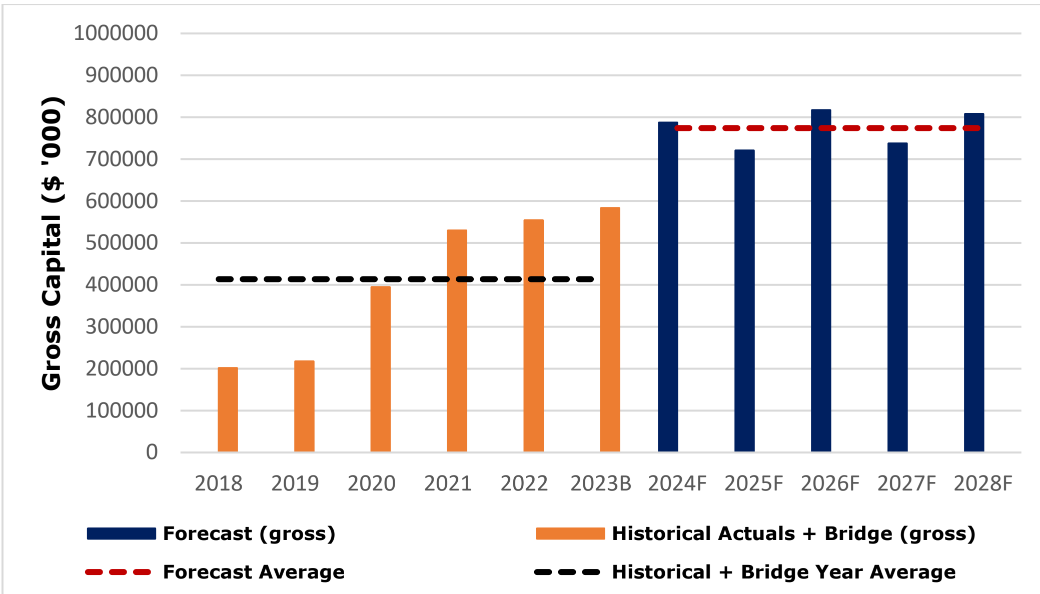
- Failure risk - multi-year planned asset replacement that addresses assets in "very poor" and "poor" condition. The historical trend has seen increasing investments due to ageing infrastructure.
- Emergency needs - emergency reactive replacement of distribution system assets due to unanticipated failure, storms, motor vehicle accidents, vandalism, etc.

Expenditures for System Renewal were occasionally shifted to accommodate additional priority investments for the system to meet the expected performance by OHL's customers. As shown in Figure 5.4-5, the forecast average is 87% higher than the historical average. OHL intends on having a more constant level of spending on renewal projects to manage the system's health and performance. Should additional funds be remaining from System Access due to fewer customer service requests than planned for, OHL intends to re-allocate funds into renewal projects to address additional at-risk assets, that would be identified through OHL's planning process. Forecasted projects are generally in alignment with the projects executed in the past such as overhead and underground renewal. The following are some of the main factors for the forecasted increase in expenditures:

- Increase in meter purchases in 2024, 2025, 2026, 2027, and 2028 to replace meters. The whole meter population requires replacement or reverification by 2028. OHL is pacing its meter programs to minimize any one-off impacts. The forecasted quantities for purchase are: 1,202 in 2024, 1,424 in 2025, 1,656 in 2026, 1,424 in 2027, and 1,712 in 2028. These purchases will be used for new installations, to replace failed existing meters, and to begin a paced renewal program for existing smart meters.

- A new replacement program to replace 1 to 2 PME switchgear a year, addressing the defective equipment issues, due to PME failures.
- A new automatic sleeve replacement program in 2024, to address increase in failures over the historical period. OHL plans to replace 431 sleeves in 2024.
- Increase in supply chain costs due to shortage of equipment, and inflation increase compared to the historical period.

Figure 5.4-5: Comparative Gross Expenditures for System Renewal



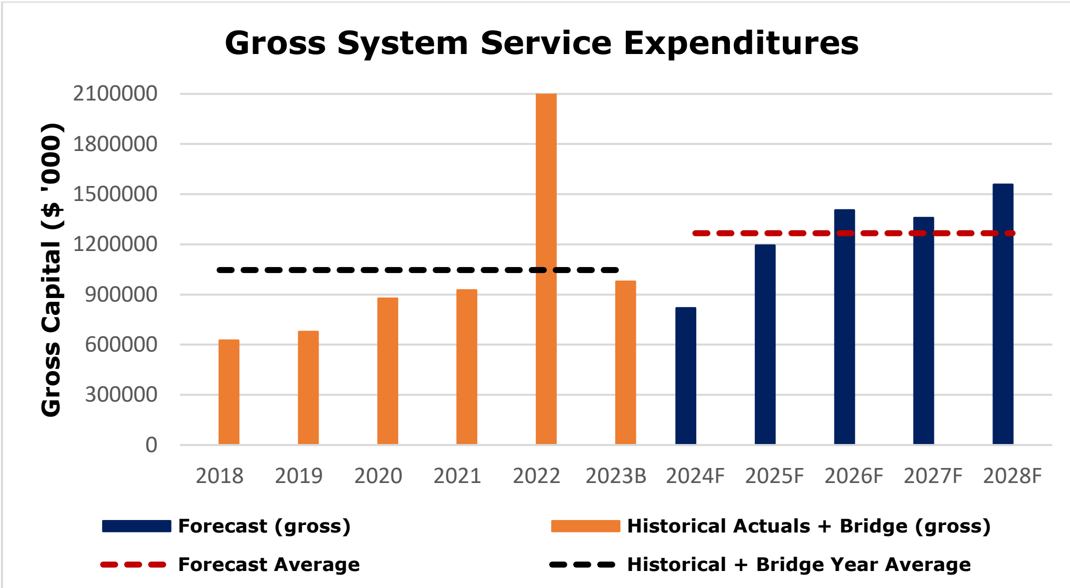
5.4.1.3.4 System Service

System Service investments include the following drivers:

- System constraints – voltage conversion, line extensions and feeder interconnections to accommodate grid load growth and modernization of the system.
- System operational objectives – investments to maintain system reliability and efficiency of distribution stations.

As shown in Figure 5.4-6, the forecast average is 14% more than the historical average. OHL is currently not planning for the installation of additional automation capabilities into the current system. The 2022 increase was due to OHL joining a fibre to the home project where multiple years of duct was installed within one year as a joint-trench project in coordination with the third-party telecommunications provider. In the forecast period, the primary reason for the increase in System Service budgets is the continuation of the 4kV voltage conversion circuits. Most of the 4kV assets remaining are underground cable and pad-mounted transformers, in which underground infrastructure costs more to replace than the overhead infrastructure. In some of the historical years, OHL had been focusing on overhead assets with minimal budget and resources being directed onto underground assets. Moving forward, the reverse effect will be seen with a higher focus of budget and resources on underground assets versus overhead assets. In addition, some of the costs increase can be attributed to inflation cost increases and recent supply chain cost increases.

Figure 5.4-6: Comparative Gross Expenditures for System Service



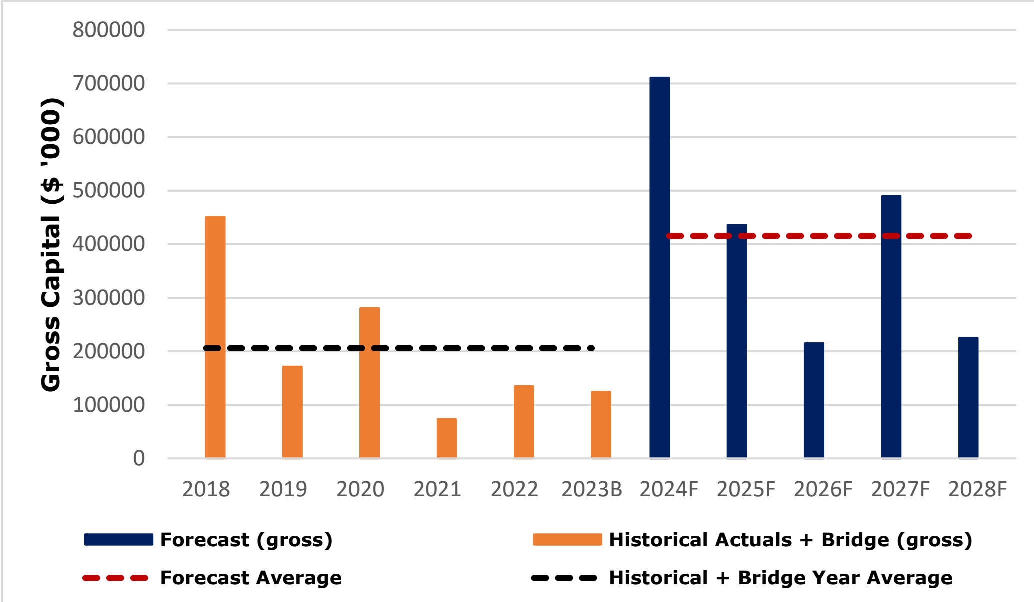
5.4.1.3.5 General Plant

General Plant investments include the following drivers:

- System Maintenance support – replacement of rolling stock, tools and replacing fleet units. Historical investments have resulted in specific rolling stock and tool replacement as required. Replacement of major fleet units tends to be a high lumpy cost in a particular investment year when compared to the replacement costs of small fleet units.
- Business Operations efficiency – GIS development, data collection efforts and computer upgrades to support daily operations and to better understand and analyze the system needs.

As shown in Figure 5.4-7, the forecast average is 102% higher than the historical average. The historical expenditures had variable spending in the General Plant category, addressing only critical items that were needed to maintain and continue operations at OHL. OHL continues to use the same framework moving forward to address only the critical issues needed to maintain the existing facilities, fleet, and IT assets. The major increase in expenditure for 2024 and 2025 are due to the need for OHL to replace the roof of its office, which has been identified as at risk of failing, with known defects and leaks been identified. Through a third-party inspection, it was recommended that the roof be replaced in 2024. This project is important to ensure OHL can keep its staff safe and provide an acceptable environment for its staff to work in and provide efficient customer service. The increase in 2027 is to address a truck that will have reached its end of life. The truck is critical in ensuring OHL can continue to maintain a 24/7 operation responding to emergency requests as well as planning maintenance and capital work.

Figure 5.4-7: Comparative Gross Expenditures for General Plant



5.4.1.4 Important Modifications to Capital Programs Since Last DSP

As described in the above sections, OHL has a couple of new replacement programs that are addressing assets that have been identified as having increasing failures and contributing heavily to the defective equipment portion of the reliability metrics. These include:

- Planned PME switchgear replacement program.
- Planned automatic sleeve replacement program.
- Paced meter replacement program for 2024-2028.
- Roof replacement project planned for 2024 & 2025.

5.4.1.5 Forecast Impact of System Investments on System O&M Costs

System investments can result in:

- the addition of incremental plant (e.g., new poles, switchgear, transformers, etc.).
- the relocation/replacement of existing plant.
- the replacement of the end-of-life plant with the new plant (e.g., cables, poles, transformers, etc.)
- new/replacement system support expenditures (e.g., fleet, building, software, etc.)

OHL employs a strategy of deferring O&M spending in areas that align with system renewal efforts, to the extent possible, where doing so will pose no safety or environmental hazard. In general, incremental plant additions will be integrated into the asset management system and will require incremental resources for ongoing O&M purposes. However, OHL balances this off with staff turnover and other efficiencies to minimize the impact, and this is expected to put a neutral to upward pressure on O&M costs.

Relocation/replacement of an existing plant normally results in an asset being replaced with a similar one, so there would be little or no change to resources for ongoing O&M purposes (i.e., inspections still need to be carried out periodically as required per the DSC). There may be some slight life advantages when a working older piece of equipment is replaced with a newer one that would impact O&M repair-related charges. Overall, the planned system investments in this category are expected to put neutral pressure on O&M costs.

Replacement of end-of-life assets with the new plant will still require the allocation of resources for ongoing O&M purposes. Repair would be the most significant O&M activity impacted by the new plant. Certain assets, such as poles, offer few opportunities for repair-related activities and generally require replacement when deemed at end of normal life or critically damaged. Other assets such as direct buried cable offer opportunities for repair-related activities (e.g., splices) up to a point where further repairs are not warranted due to end-of-life conditions. In a few areas, cable faults will not be repaired due to cable end of life. When faulted, the faulted cable section will be replaced, normally a section between two distribution transformers. For planned cable replacement in a subdivision, a new primary cable installed in the duct replaces direct buried primary cable and is expected to provide higher reliability. This will shift response activity for a cable failure from repair (O&M) to replacement (capital). If assets approaching the end of life are replaced at a rate that maintains equipment class average condition, then one would expect little or no change to O&M costs under no growth scenarios but would still see upward O&M cost pressure in growth scenarios (more cumulative assets to maintain each year). Replacement rates that improve equipment class average condition could result in lowering certain maintenance activities costs (e.g., pole testing, reactive repairs, etc.). Overall, this is expected to put slight downward pressure on O&M repair-related costs.

System support expenditures (e.g., GIS, Asset Condition Assessment studies) are expected to provide a better overall understanding of OHL's assets that can lead to a more efficient and optimized design, maintenance and investment activities going forward. Asset Condition Assessment studies have been conducted and data gaps have been identified. To improve the quality of data used in the ACA studies, increased data collection efforts may be implemented which can increase pressure on O&M costs. Collected data will be inputted into the GIS as attribute information for each piece of plant. Improved asset information can allow existing resources to partially compensate for growth-related increases in O&M activities. Fleet replacement expenditures result in reduced O&M for new units however this will be offset by increasing O&M of remaining units as they get older. Overall, the system investments are not expected to have a significant impact on total O&M costs in the forecast period.

Typically, O&M costs are expected to increase over the forecast period due to labour costs, supply chain and contractors' costs. The retirement of a Lines Supervisor in late 2026 is causing a future decrease in O&M. It is important to OHL to undertake accurate budgeting with the information known at the time, but as future plans and workload changes, it is uncertain whether this position will be replaced at this point.

Table 5.4-15: Forecast System O&M Expenditures

Category	Forecast ($)				
	2024	2025	2026	2027	2028
System O&M	1,359,282	1,393,264	1,379,096	1,169,562	1,198,802

5.4.1.6 Non-Distribution Activities

OHL confirms that there are no expenditures for non-distribution activities in the OHL's budget.

5.4.2 Justifying Capital Expenditures

Customer Value

OHL regularly engages with its customers to share information, educate customers, and to gather their opinions and insights on its services and on key priorities. Customer needs, preferences, priorities and expected level of service are key inputs considered when developing capital plans.

Through the prioritization of System Access projects such as new customer connections, service requests and new subdivisions, OHL ensures that customer needs and requests are being met.

The scope of capital investments planned in the System Renewal category has also been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level while also keeping the overall investment envelope for this DSP within a range that would not result in retail rates escalations beyond the affordability of OHL's customer base. This aligns with its two customer priorities identified in a recent survey, which corresponds to "*Reliable Power*" and "*Reasonable Costs*".

OHL's System Service investments in its voltage conversion programs will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6 kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16 kV substations, enhanced public safety through the relocation of utility plant from backyards to public rights of way and the satisfaction of customer expectation for a system with high-reliability standards.

OHL's General Plant investments are also selected and prioritized such that OHL can continue to operate safely, efficiently and support other work. Work on replacing its roof, will ensure its employees have a safe space to work and continue to serve its customers in an efficient manner.

In order to align OHL's overall capital budget envelope with customer expectations, OHL has prioritized and optimized its proposed capital investments such that the most critical projects and programs have been budgeted over the forecast, while a number of lower priorities, less critical scoped projects and programs have been either deferred, reduced, or eliminated from the budget envelope.

Technological Changes and Innovation

OHL ensures it keeps abreast of the latest grid innovations and any technological changes that could help enhance OHL's network and continue to deliver a safe and reliable service that meets its customer expectations. A few examples of technological improvements and innovation either recently implemented or planned over the forecast period are noted below:

- Hardware Replacement- Automatic Sleeve Replacement – In 2020, an automatic tension sleeves failed resulting in the feeders tripping and live conductor falling to the ground. OHL quickly restored the conductor and carried out an infrared scan of that area and the entire service territory to detect other failing sleeves. To address this issue, OHL has created a program (January 2023) to remove all automatic tension sleeves, to be replaced with compression sleeves. In addition, by implementing compression sleeves, this will reduce any cost that would be associated with OHL responding to restoring failed automatic tension sleeves.
- OHL has continued its effort to replace porcelain cutouts with polymer cutouts during planned maintenance and capital projects. By replacing these assets during planned maintenance and other capital project, OHL can maximise its cost efficiency on replacing these assets to the latest standards.
- OHL has continued with a program to change to stainless steel transformers for single phase pad mounted transformers, enhancing the durability of its transformers, as well as employing the ese of Internal Fault Detector for all transformers.

Consideration of Traditional Planning Needs

As previously explained in Section 5.3.1, traditional planning needs, including load growth, asset condition, and reliability are key inputs considered as part of OHL's AM processes.

OHL undertakes load studies to identify areas that may require investments to accommodate required capacity. Load growth is a direct input into OHL's planning for System Access and System Service type projects. Load growth is also a key input into the regional planning process (detailed in Section 5.2.2.4) which helps to identify future requirements (both wires and non-wires) to accommodate load growth.

Asset condition and reliability data are key inputs considered by OHL when identifying, selecting, and prioritizing System Renewal expenditures. Through a recently completed ACA exercise, several assets have been identified as in need of replacement now or in the near future. In the absence of investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety.

However, renewal and replacement of all infrastructure components determined to be in "fair," "poor," or "very poor" condition during the next five years would be difficult to manage through OHL's resources and it would lead to unaffordable increase in retail rates. Given that the top two customer priorities correspond to "*Reliable Power*" and "*Reasonable Costs,*" OHL's challenge is to seek an optimized balance of these generally opposing factors.

One example of a project OHL is undertaking that will address reliability issues, is it Automatic Tension Sleeve replacement program. Through this program OHL is mitigating an identified issues with this asset that had caused impacts to reliability.

<u>Overall Capital Expenditures</u>

OHL has outlined the details of its forecast capital expenditure in Section 5.4.1.2. Further justification for its material investments can be found in Appendix E, which outline the justification for each material investment.

5.4.2.1 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. OHL materiality threshold is $10,000.

Table 5.4-16: Test Year Material Investment List

Category	Project Code	Project Name/Description	Priority Rank[8]	2024 Expenditure ($ '000)		
				Gross	Contr.	Net
System Access	C01-2024	Various General Service Capital Contribution Projects	**1**	80	(40)	40
	C02-2024	Various Residential Capital Contribution Projects	**2**	30	(25)	5
	S01-2024	Various Subdivisions	**3**	1,242	(646)	596
System Renewal	B00-2024	Transformer and PME Replacements	**5**	169	0	169
	H00-2024	Hardware Replacement	**6**	227	0	227
	M00-STOCK-2024	Meter Replacement and Additions	**4**	243	0	243
	P00-2024	Pole Replacement	**7**	148	0	148
System Service	B121-2024	MS2 East Feeder Conversion	**15**	420	0	420
	B122-2024	MS2 South Feeder Conversion	**8**	210	0	210
	B2024-1	Ontario and Victoria Street Voltage Conversion	**10**	189	0	189
General Plant	GP 2024-1	Building	**11**	296	0	296
	GP 2024-2	Office Equipment	**16**	30		30
	GP 2024-3	Computer Equipment	**9**	58	0	58
	GP 2024-4	Computer Software	**12**	197	0	197
	GP 2024-5	Vehicles	**13**	94	0	94
	GP 2024-8	Measurement and Testing	**14**	24	0	24

[8] OHL's process for determining the priority rank for each project is outlined in section 5.3.1.3

Appendix A – OHL's Business Plan

ORANGEVILLE HYDRO
BUSINESS PLAN

2024
BUSINESS PLAN

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1. EXECUTIVE SUMMARY

Orangeville Hydro Limited's Business Plan for 2024-2028 is developed in conjunction with the strategic plan, goal setting and target planning. This business plan is also based on Ontario Energy Board (OEB) initiatives and governmental public policy responsiveness as well as our internal conception of the utility to meet certain other objectives in creating efficiencies. These objectives are met while maintaining safety, excellent customer service objectives and focus, system reliability, and stable financial performance.

The key areas that are reviewed within this Business Plan are:

- Mission statement, Vision statement and Values statement
- Strategic Objectives
- SWOT Analysis
- Local economic overview and customer description
- Performance metrics
- Future Capital and Operating plans
- Financial Summary

2. MISSION, VISION, AND VALUES

Orangeville Hydro's strategies are in harmony with our corporate values, our vision, our mission statement as well as our approach to a balanced scorecard within an evolving electricity marketplace.

VISION

"TO BE ACKNOWLEDGED AS A LEADER AMONG ELECTRIC UTILITIES IN THE AREAS OF SAFETY, RELIABILITY, CUSTOMER SERVICE, CUSTOMER SATISFACTION, SUSTAINABILITY, AND FINANCIAL PERFORMANCE."

MISSION

To provide safe, reliable, efficient delivery of electrical energy while being accountable to our shareholders...the citizens of Orangeville and Grand Valley.

While we must operate as a business and be profitable for our shareholders, our main reason for existing is to provide safe, reliable, and economic electricity services to the people of the Town of Orangeville and the Town of Grand Valley. That is what distinguishes us from other large, remotely owned and controlled energy companies.

VALUE STATEMENT

To continue into the future as a profitable electricity distribution enterprise the following principles are core values of our Company:

- We value professionalism and safety in our service and our work.
- We value people - our customers, employees, board members, and shareholders.
- We value our community - its environment and its economic progress.
- We value integrity, honesty, respect, and communications.
- We value local control, local accountability, local employment, and local purchasing; and
- We value easy accessibility for our customers.

3. SWOT ANALYSIS

An essential element of our strategy is to ensure Orangeville Hydro Limited is ready to embrace change and disruption in our sector. In a period of significant transformation, the ability to not only accommodate change, but to make the most of it, is likely to be a distinguishing characteristic of those utilities that continue to thrive. We will advocate and lobby for public policy that benefits our customers now and in the future.

STRENGTHS

We have positive relationships with our shareholders – the people of Orangeville and Grand Valley, individual customers, and their elected representatives.

We have a core of high-quality employees, effective management, and solid relations between the staff and the Board of Directors.

We have a well-maintained distribution system because of effective capital planning and maintenance efforts. This is proven by strong historical reliability statistics and the ability to connect new customers.

As a small organization, we have the advantage of being flexible and nimble when it comes to implementing change and reacting to threats quickly.

We have a high level of quality customer service and customer satisfaction, based on survey results.

We have a strong relationship with local organizations, including the Home Builders Association, Dufferin Board of Trade, the County of Dufferin, Social Services, and service clubs.

We have stability within our revenues due to operating within a regulated environment as well as our customer demographics. Our residential customers provide 65% of our revenue and the remainder is received from a diverse mix of small commercial, institutional, municipal, and industrial customers. Our largest customer accounts for 1.8% of our total distribution revenue.

Intensification is occurring within our service territory which is contributing to continuous customer growth and increasing the efficiency of our distribution system.

Due to historical diligence in our succession planning, our workforce is in a stable position with exceptional leadership in place.

WEAKNESSES

We have limited land for large residential and industrial developments within our service area.

The strict regulated environment limits the scope of potential business opportunities.

We have a lean workforce. Therefore, when a departure or a leave of absence occurs the impact is significant and challenging.

OPPORTUNITIES

Orangeville Hydro can be a solutions provider to improve our customer's experience.

We can investigate expanding our service area by working with developers surrounding the existing service area and applying for Service Area Amendments.

The post-pandemic recovery created an environment to find creative solutions to serve our customers and continue the operation of all business activities under different circumstances such as working remotely. The post-pandemic recovery is an opportunity to challenge the status quo and find more new ways of operating as an organization.

We have an opportunity to maintain a high standard of service for our customers, contribute to the welfare of our local community, and return profits to the citizens of Orangeville and Grand Valley for their local benefit rather than remote corporate gain.

We can help increase our customers' knowledge regarding the safe use of electricity and energy efficiency solutions to reduce their energy costs.

The opportunities for customer interaction and control are growing daily, as are our customers' expectations for choice, convenience, and responsiveness.

THREATS AND UNCERTAINTIES

The post-pandemic economic environment has created new threats and uncertainties regarding impacts to staffing levels, distribution revenue, increasing costs of services and materials, and increasing debt servicing costs.

The post-pandemic recovery has created new threats and uncertainties such as a supply chain crisis and a high inflationary economic environment.

The Ontario electricity sector is subject to the current direction of the provincial government which shifts due to the four-year provincial election cycle. The changes in government create uncertainty for the direction of the Ministry of Energy and other Ministries that affect the electricity sector.

The implementation of various rules and regulations by the Ontario Energy Board will make it difficult for distribution companies to collect from customers that default on their bill payments and increase the risk of bad debts.

Revenue recovery is based on approval from the Ontario Energy Board. The expectations and requirements of the Ontario Energy Board are continually changing and placing downward pressure on revenue recovery.

There are increased uncertainties regarding technological advances, climate change, and cyber security (world-wide threats) that need to be considered.

CAPABILITY

A highly skilled, properly trained, and knowledgeable workforce is essential to Orangeville Hydro's continued success. Like many other companies and utilities, Orangeville Hydro's continuing comprehensive succession planning is aimed at anticipating and fulfilling current and potential employee needs, through planning, talent attraction, effective deployment of resources, performance management, and development.

4. STRATEGIC OBJECTIVES

We will use the following strategies to overcome our weaknesses and threats and capitalize on our strengths and opportunities. These strategies will also be in harmony with the corporate values, vision, and mission statement.

SAFETY

Health and safety will continue to be paramount for the company.

We provide safe work practice training for all employees consistent with industry best practices. We will continue to seek new ways to further communicate and promote a safety culture to our employees, our customers, and our community both inside and outside the workplace.

CUSTOMER FOCUS

As the customer's role within the electricity system evolves, successful utilities will be those who recognize that customers are not all the same. A willingness to invest in the skills, culture, technology, and practices needed to leverage those tools will be a key difference between leading and trailing utilities in a more customer-centric landscape.

We will adapt and tailor the service delivery methods to the specific needs of individual customers and leverage technology to enhance the customer experience and increase operational agility.

Tools exist for Orangeville Hydro to understand and engage our customers at an individual level and provide a truly personalized service. Leveraging the power of our continuously growing databases, evolving social media platforms, and the convenience of mobile technology, we can anticipate our customers' needs with increasing precision to create a more effortless customer experience.

OPERATIONAL EFFECTIVENESS

We will continue to leverage the benefits of collaboration with the CHEC membership, Electricity Distributors Association, Utility Collaborative Services, and Utilities Standards Forum.

We will continue to network with other boards, stakeholders, and other utilities to develop and share best practices.

We will investigate areas that are within our control to reduce or curtail costs to better utilize resources.

We will ensure our infrastructure is maintained properly by implementing our Distribution System Plan as well as our annual Distribution Maintenance Program.

We will pursue diversity, equity, and inclusion genuinely and intentionally as both the right and smart thing for the business and a better future for all employees.

We will invest heavily in our staff and rely on them to help us accomplish our goals through the following activities:

- We will keep our people informed;
- We will make sure our people understand what we expect from them and why they are important to the organization;
- We will support our people by providing them with information, tools, equipment, standard policies & procedures, and training;
- We will utilize a pay-for-performance model for the management team and attempt to link their compensation with their performance and the performance of the company;
- We will continue to carry out our succession planning processes.

PUBLIC POLICY RESPONSIVENESS

We will ensure our distribution system can accommodate Distributed Energy Resources (PV solar, combined heat and power, battery storage, and small natural-gas generators) and electric vehicle technology.

We will support low-carbon energy generation and use within our service area.

We will become a net-zero emissions company by 2050 to help Canada and Dufferin County reach their current climate targets.

We will continue to successfully deliver Provincial Programs to our customers such as the Industrial Conservation Initiative, the Energy Affordability Program, the Ontario Electricity Support Program, the Low-Income Energy Assistance Program, and potential future energy efficiency programs.

We will deliver obligations mandated by government legislation and regulatory requirements.

We will investigate improved and additional business activities to improve shareholder value, empower the customer, and advance with innovation.

FINANCIAL PERFORMANCE

We will maximize financial viability by investigating efficiencies and maintaining prudent cost savings. We will aim to remain a top cohort utility for cost performance within the OEB's Cost Performance benchmarking report.

We will continue to maintain just and reasonable rates for our customers while aiming to achieve or exceed our deemed rate of return.

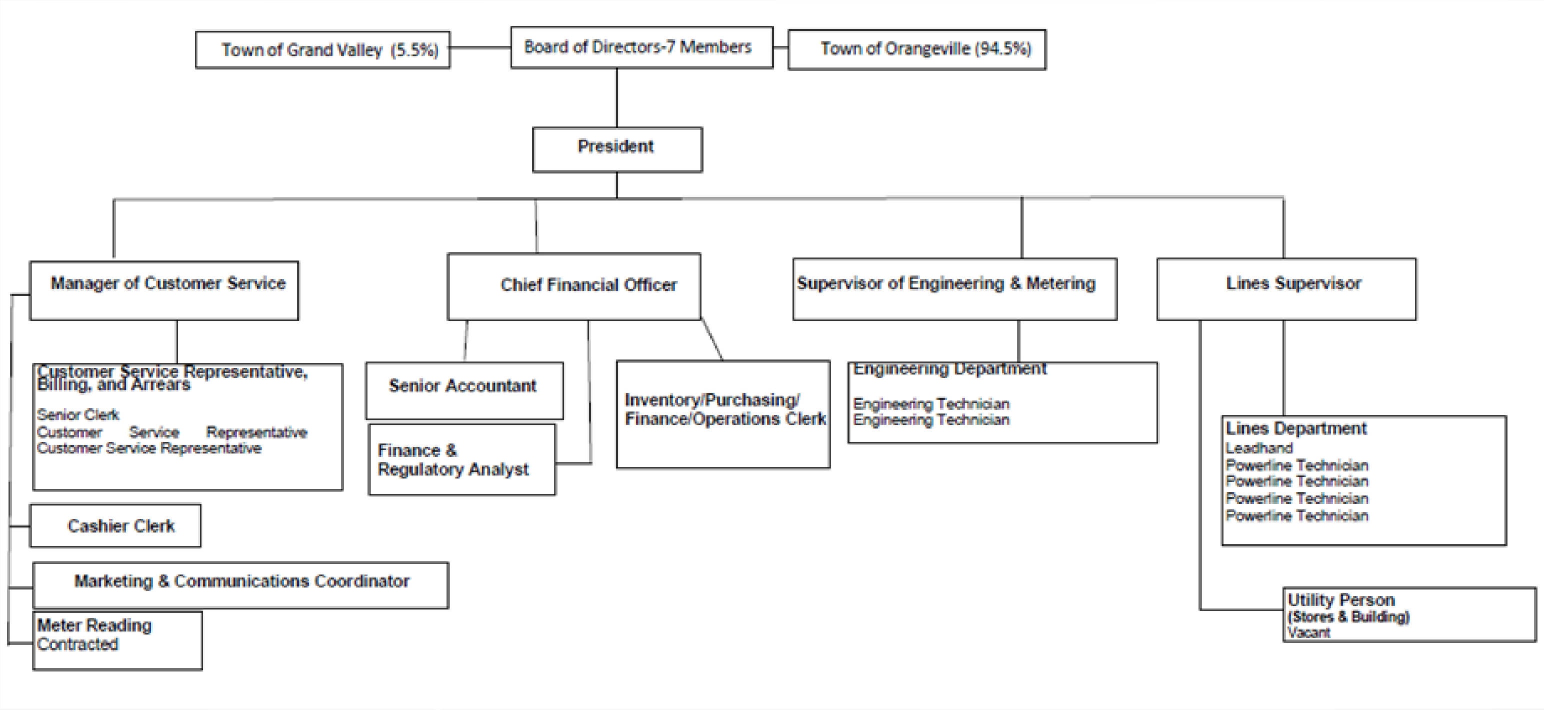
We will continue to ensure we have a high level of performance relative to our industry peers by continually reviewing the OEB LDC Yearbook data, OEB Activity & Program-based Benchmarking data, and our year-to-year trending.

We will investigate feasible opportunities to grow the regulated distribution business.

5. ABOUT THE UTILITY

The Energy Competition Act, 1998 required local distribution utilities like Orangeville Hydro to become incorporated according to the Ontario Business Corporations Act by November 7, 2000. Hence on October 2, 2000, the Town of Orangeville passed a by-law transferring all assets and liabilities of the Orangeville Hydro-Electric Commission to Orangeville Hydro Limited (Orangeville Hydro). Orangeville Hydro is considered a local distribution company or a wires company. In 2009, Orangeville Hydro and Grand Valley Energy Inc. merged. Since then, Orangeville Hydro has been owned by the Town of Orangeville (94.5%) and the Town of Grand Valley (5.5%). Orangeville Hydro is licensed by the Ontario Energy Board to operate as an electricity distribution company within the current boundaries of the Town of Orangeville and the former Village of Grand Valley. Successful Service Area Amendments have allowed Orangeville Hydro to grow our service area beyond our original limits of the former Village of Grand Valley.

Orangeville Hydro must operate its business in compliance with all applicable laws, including the Electricity Act, 1998, the Ontario Energy Board Act, 1998, the Ontario Business Corporations Act, and the rules, policies, and requirements of the OEB. These include the Distribution System Code, the Affiliate Relationships Code, the Retail Settlement Code, the Standard Supply Service Code, the Accounting Procedures Handbook, and the Uniform System of Accounts as well as the applicable Rate Handbook and Filing Requirements.



6. ECONOMIC OVERVIEW AND CUSTOMER DESCRIPTION

ECONOMIC OVERVIEW OF THE SERVICE AREA

Orangeville Hydro's service area has a population of approximately 35,000 and is expected to grow to 42,540 by 2036 according to forecasts contained within the Dufferin County Official Plan (2017). This growth is constrained beyond these numbers due to the limited residential land development in the Town of Orangeville and the limited municipal water service and municipal sewage service in both the Town of Orangeville and the Town of Grand Valley.

The Town of Orangeville is the urban hub of Dufferin County. The population of approximately 31,000 people sustains strong commercial retail stores that includes big box stores, nationwide commercial retail stores, and small locally owned retail stores. Orangeville has a strong group of manufacturers in sectors such as plastics, food products, woodworking, aerospace, and automotive. The economic base of the Town of Orangeville is diversified between many sectors.

The Town of Grand Valley is a fast-growing area within Dufferin County. Orangeville Hydro services the urban settlement area and Hydro One services the surrounding rural farmlands. The urban settlement area of the Town of Grand Valley has a population near 4,000 and is growing through both intensification and greenfield developments. The Town of Grand Valley is an urban hub with businesses for shopping, dining, and services.

CUSTOMER DESCRIPTION

Orangeville Hydro's breakdown of customers by class is shown below:

TABLE 2: CUSTOMERS BY CLASS DECEMBER 31, 2022

Customer Class	Number of Customers
Residential	11,560
General Service < 50 kW	1,161
General Service > 50 kW	125
Sentinel Lights	34
Street Lights	3
Unmetered Scattered Load	31
Generation	42
Total	**12,956**

Orangeville Hydro has a steadily growing base of residential customers with new subdivisions being energized in both Orangeville and Grand Valley. There is also significant redevelopment and intensification occurring within both communities. The intensification projects will continue to increase Orangeville Hydro's density metrics such as customers per kilometer of line and customers per square kilometer. Orangeville Hydro has a diverse manufacturing sector, with several large industrial customers in the plastics, food product, and automotive manufacturing sectors.

TABLE 3: AVERAGE MONTHLY CONSUMPTION PER CUSTOMER (kWh)

Customer Class	2014	2015	2016	2017	2018	2019	2020	2021	2022
Residential	720	699	690	661	709	685	732	723	721
General Service < 50 kW	2,640	2,609	2,630	2,605	2,680	2,625	2,523	2,507	2,651
General Service > 50 kW	74,861	79,164	77,689	83,342	84,012	83,963	87,180	90,963	95,139
Sentinel Lights	64	60	52	59	58	57	57	57	55
Street Lights	55	51	30	27	26	26	26	25	26
Unmetered Scattered Load	462	348	318	361	338	338	338	335	335

Orangeville Hydro has witnessed steady consumption usage for most of our customer classes. A fluctuation in residential usage can be due to conservation activities, installation of more efficient equipment, improved building code requirements in new homes, intensification decreasing the average size of a household, our customers converting from electrical heating equipment to natural gas, and residential customers working from home. The usage is not necessarily consistent as weather patterns such as extreme heat waves or extended periods of extreme cold are not consistent year to year. Residential distribution rates are based on a fixed service charge, and therefore provide a stable revenue source.

The average usage of a General Service >50kW customer has increased from 2014 compared to 2022 as our largest customers have expanded.

The average monthly consumption for a streetlight connection significantly decreased in 2016 due to the High-Pressure Sodium to LED light conversions that occurred in late 2015 & 2016.

7. PERFORMANCE METRICS AND FUTURE PLANS

2022 SCORECARD MANAGEMENT DISCUSSION AND ANALYSIS

The performance outcomes outlined in the RRFE are measured on the LDCs scorecard which is published annually. In 2022 Orangeville Hydro exceeded all of its performance targets. A discussion of the scorecard results follows the reproduction of the scorecard below.

The scorecard is published annually by the Ontario Energy Board around mid-July, therefore the next scorecard which will include 2023 audited results will be posted around July 14, 2024.

Performance Outcomes	Performance Categories	Measures		2018	2019	2020	2021	2022	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	99.24%	100.00%	down	90.00%	
		Scheduled Appointments Met On Time		99.76%	100.00%	100.00%	99.25%	100.00%	down	90.00%	
		Telephone Calls Answered On Time		99.94%	99.90%	99.11%	99.21%	99.26%	down	65.00%	
	Customer Satisfaction	First Contact Resolution		99.9	99.9%	99.9	99.83%	99.62%			
		Billing Accuracy		99.99%	100.00%	99.84%	99.82%	99.73%	down	98.00%	
		Customer Satisfaction Survey Results		78.2%	78.2	76	76	76			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		86.20%	85.50%	85.50%	84.50%	84.50%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	flat		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	0	0	1	0	flat		0
			Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.450	0.000	flat		0.063
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		0.29	0.33	1.01	1.75	0.47	up		0.55
		Average Number of Times that Power to a Customer is Interrupted [2]		0.16	0.39	0.75	0.91	0.52	up		0.65
	Asset Management	Distribution System Plan Implementation Progress		87%	96%	102	87%	156%			
	Cost Control	Efficiency Assessment		2	2	2	1	1			
		Total Cost per Customer [3]		$551	$568	$535	$550	$605			
		Total Cost per Km of Line [3]		$31,233	$32,501	$30,612	$31,921	$35,340			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed On Time [4]									
		New Micro-embedded Generation Facilities Connected On Time		100.00%						90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.56	1.74	1.41	0.78	1.39			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.05	1.15	1.12	1.12	1.28			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	9.36%	9.36%	9.36%	9.36%	9.36%			
			Achieved	11.92%	10.36%	11.83%	9.46%	5.71%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor's reported information.
4. Value displayed for 2021 reflects data from the first quarter, as the filing requirement was subsequently removed from the Reporting and Record-keeping Requirements (RRR).

Legend: 5-year trend: up, down, flat. Current year: target met, target not met.

GENERAL SCORECARD OVERVIEW

In 2022, Orangeville Hydro exceeded all performance targets. Aging distribution infrastructure continues to be a challenge for many utilities today. Like most utilities in Ontario, Orangeville Hydro must replace aging infrastructure at a steady pace to meet this challenge. Therefore, Orangeville Hydro strategically plans to manage the renewal and growth of the distribution system in a cost-effective manner. In addition, vegetation control, including line clearing activities, were continued in the year to reduce the vulnerability and improve the reliability of the distribution system to external uncontrollable events, such as weather.

Orangeville Hydro continues to focus on providing value to our customers. Orangeville Hydro offers “Customer Connect” to assist our customers with interactive information that will permit them to better monitor, understand, and control their electricity consumption. Orangeville Hydro is continually improving our website, which allows customers an improved experience when interacting with us. Orangeville Hydro’s social media presence has increased, to provide immediate updates for outages as well as current news. Orangeville Hydro makes every effort to engage its customers on a regular basis to ensure that we are aware of their needs and that they are receiving the best value for their dollar.

In 2023, Orangeville Hydro will continue its efforts to improve its overall scorecard performance results as compared to prior years. This performance improvement is expected because of continued investment in both the infrastructure and in the response to the customers’ needs.

PACIFIC ECONOMICS GROUP (PEG) REPORT

The PEG report compares utilities' cost efficiencies on a consistent basis. The report is issued annually and is publicly available on the OEB website. The PEG report provides a ranking of the utilities included in the study, summarizes the results, and provides insight into the trends in utility efficiency scoring. Orangeville Hydro moved up to Group 1 efficiency ranking back in 2021, after moving to Group 2 in 2017 (as per PEG 3-year average). The utility is continuously looking for ways of finding efficiency in its Operations, Maintenance and Administration costs thus reducing rates.

TABLE 4: PEG PAST PERFORMANCE (STRETCH FACTOR)

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Stretch Factor Cohort - Annual result	3	3	3	2	2	2	2	1	1
Associated Stretch Factor Value	0.30	0.30	0.30	0.15	0.15	0.15	0.15	0.00	0.00

The summary of cost performance results shows the actual total cost on an annual basis used to complete the PEG analysis. A negative percentage difference means that actual total costs are less than predicted costs. Total cost is a calculation of adjusted OM&A expenses, plus capital costs, and other variables. Shown below, the differential between actual total cost and predicted costs becomes increasingly larger with each year, which is why in 2021 Orangeville Hydro was moved to Group 1. Moving to a higher group would historically have provided Orangeville Hydro with a larger increase in distribution revenue as a bonus for increased cost efficiencies.

Annually, distribution rate increases are set using two values: Price Escalator and Stretch Factor. The distribution rates are increased by the Price Escalator percentage and decreased by the Stretch Factor percentage. This means the higher the PEG report rating, the lesser the rates will be decreased by the Stretch Factor, therefore allowing a higher increase in distribution revenues. Unfortunately, currently the PEG report rating does not affect Orangeville Hydro, because in 2020, when Orangeville Hydro received its Cost of Service deferral approval for 2021 rates, the OEB determined that Orangeville Hydro will complete its next IRM rate application using the Annual IR methodology. This means that until we complete our next Cost of Service rate application in 2024, the Stretch Factor will always be set at the highest value of .6%, therefore reducing distribution rates by this amount. After our Cost of Service is complete, we will then receive the lower Stretch Factor decrease, therefore increasing distribution revenue.

TABLE 5: SUMMARY OF COST PERFORMANCE RESULTS

	2014	2015	2016	2017	2018	2019	2020	2021	2022
Actual Total Cost	$ 6,743,925	$ 6,848,039	$ 6,904,089	$ 6,836,145	$ 6,933,646	7,182,788	6,795,755	7,022,686	7,774,710
Percentage Change on previous year		1.5%	0.8%	-0.98%	1.43%	3.59%	-5.39%	3.34%	10.71%
Percentage Difference (Cost Performance) per PEG Analysis	-4.0%	-7.6%	-10.2%	-14.3%	-20.0%	-20.7%	-28.8%	-29.6%	-28.9%
Three year average performance			-7.3%	-10.7%	-14.8%	-18.3%	-23.2%	-26.4%	-29.1%

DISTRIBUTION REVENUE

The Ontario Energy Board compiles an annual Yearbook which contains various financial and non-financial statistics of all utilities in the province. This report allows comparison between Orangeville Hydro and LDCs with similar characteristics, as well as neighbouring LDCs. The following charts highlight the efforts taken by Orangeville Hydro to keep the distribution revenue rates for our customers lower than many other LDCs, and significantly lower than Hydro One. A three-year average from 2019-2021 was chosen to reduce the effect of anomalous data points that occur within a single year.

TABLE 6: DISTRIBUTION REVENUE – RESIDENTIAL CUSTOMER RATE PER MONTH

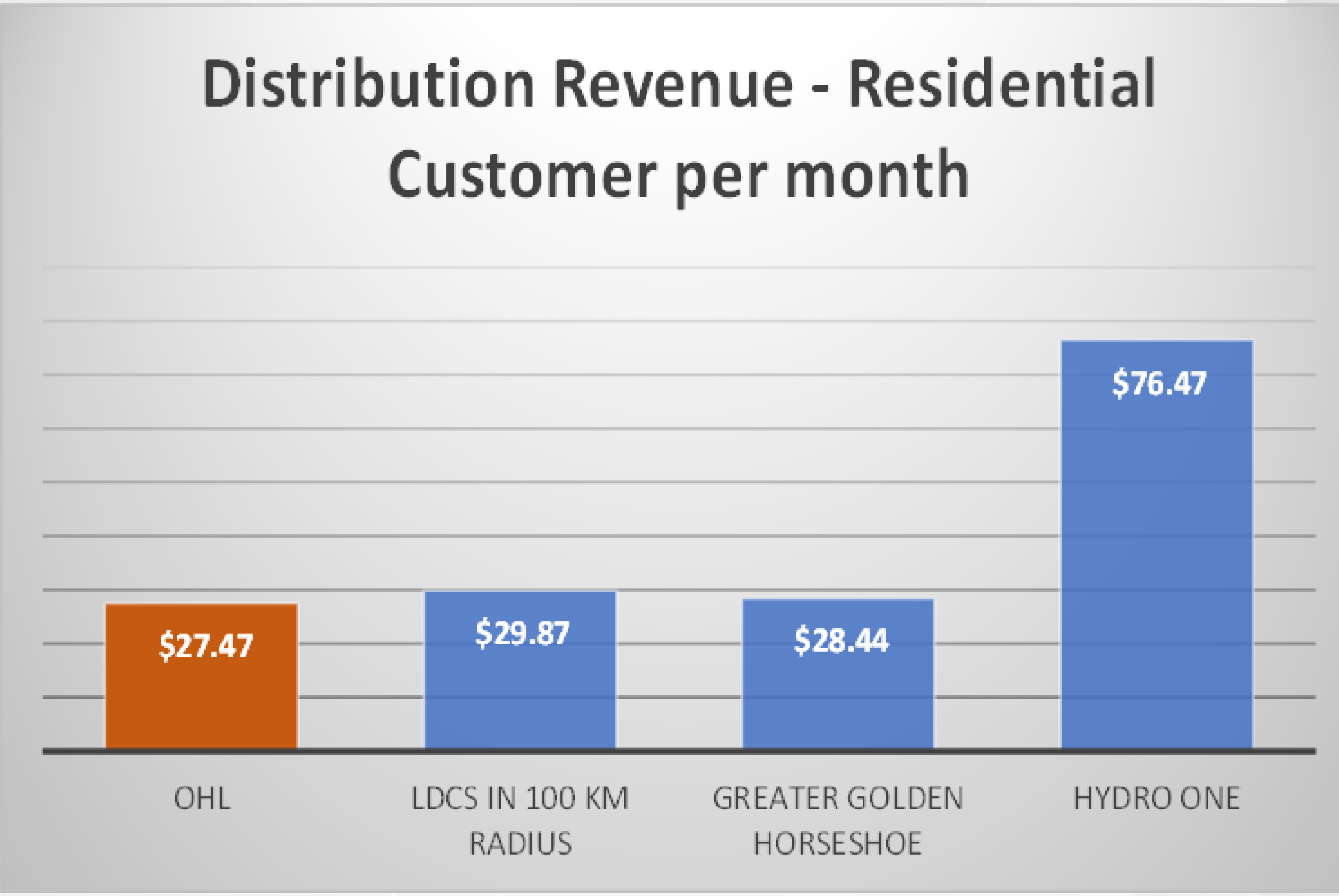


TABLE 7: DISTRIBUTION REVENUE – GENERAL SERVICE < 50 KW CUSTOMER RATE PER MONTH

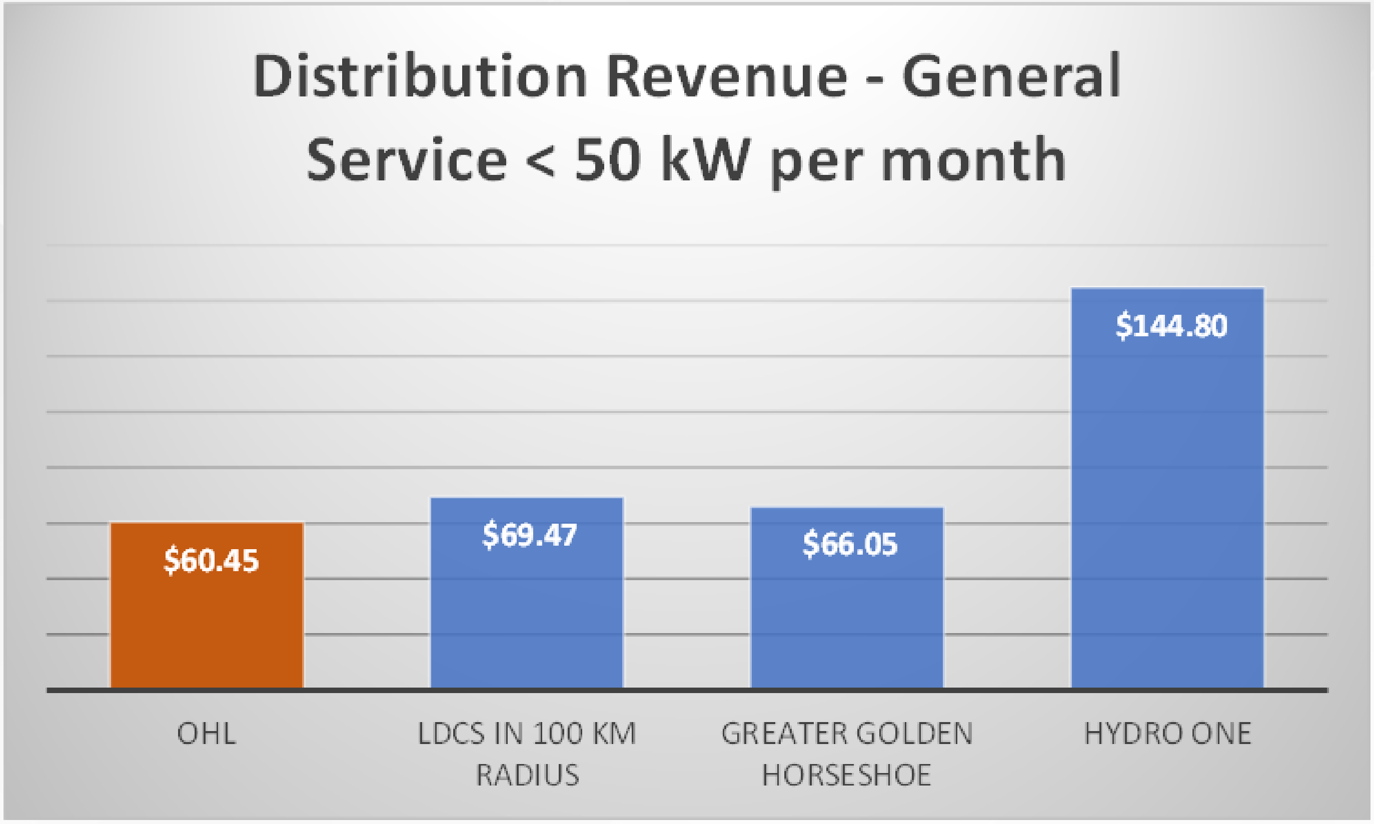
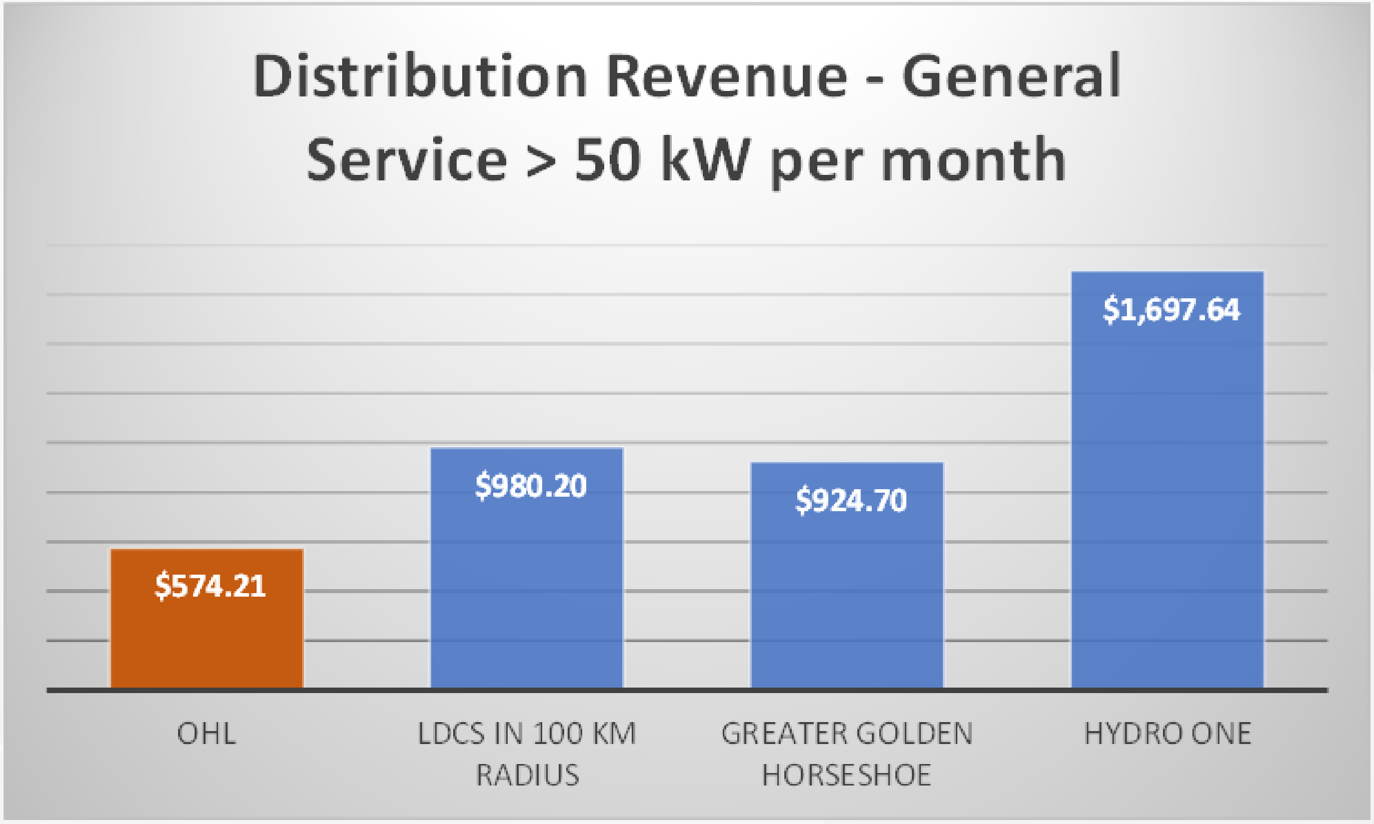


TABLE 8: DISTRIBUTION REVENUE – GENERAL SERVICE > 50 KW CUSTOMER RATE PER MONTH



COST OF SERVICE (COS) RATE APPLICATION

In 2024, Orangeville Hydro will complete a Cost of Service rate application. A COS is essentially a detailed business plan and budget, laying out the strategic vision for the next 5 years. The COS determines the level of spending and investments that Orangeville Hydro will make, including equipment, infrastructure, maintenance, service offerings, rates customers pay and more. All costs must be presented and justified by the LDC before being reviewed by the OEB. Orangeville Hydro last completed a COS application for 2014 rates. This COS will mainly affect the distribution revenue that will be paid by each customer through their service charge (fixed rate) and distribution volumetric (variable rate) charge.

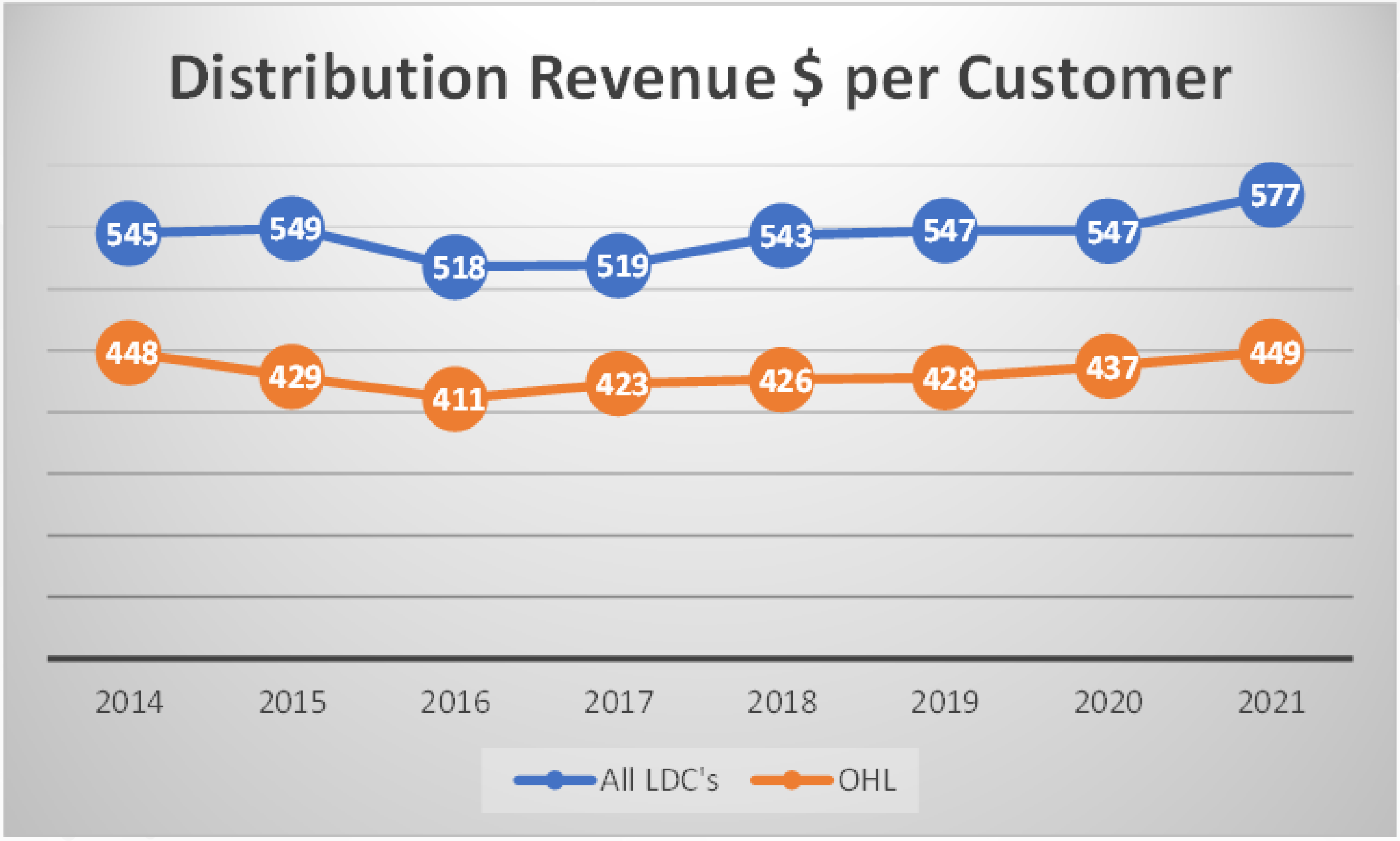
HISTORICAL AND PROPOSED REVENUES

The historical customer growth has allowed Orangeville Hydro's overall distribution revenue to increase without significantly increasing the distribution revenue per customer.

TABLE 9: HISTORICAL AND PROPOSED DISTRIBUTION REVENUES

		Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Forecast	Budget
		2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Residential	Fixed Rate	$ 15.25	$ 15.45	$ 18.19	$ 21.00	$ 23.72	$ 26.62	$ 27.11	$ 27.54	$ 28.28	$ 29.16	$ 32.82
	Variable Rate	$ 0.0131	$ 0.0133	$ 0.0102	$ 0.0069	$ 0.0035	$ -	$ -	$ -			
	Customers	10,407	10,570	10,730	11,084	11,285	11,360	11,409	11,483	11,560	11,643	11,725
	kWh	89,859,649	88,658,010	88,848,347	87,913,227	96,120,656	93,470,023	100,184,806	99,647,947	99,959,003	101,218,123	97,826,124
	Revenues	$ 3,187,626	$ 3,090,922	$ 3,200,973	$ 3,352,629	$ 3,602,177	$ 3,631,125	$ 3,757,300	$ 3,889,196	$ 3,693,685	$ 4,104,126	$ 4,617,326
GS<50	Fixed Rate	$ 31.21	$ 31.62	$ 32.19	$ 32.71	$ 33.00	$ 33.45	$ 34.07	$ 34.62	$ 35.55	$ 36.65	$ 41.72
	Variable Rate	$ 0.0095	$ 0.0096	$ 0.0098	$ 0.0100	$ 0.0101	$ 0.0102	$ 0.0104	$ 0.0106	$ 0.0109	$ 0.0112	$ 0.0127
	Customers	1,141	1,132	1,129	1,149	1,164	1,163	1,164	1,168	1,161	1,158	1,176
	kWh	36,140,162	35,440,740	35,626,425	36,041,070	37,480,006	36,623,491	35,247,190	35,138,692	36,930,708	36,254,139	35,834,680
	Revenues	$ 795,437	$ 751,287	$ 765,543	$ 919,218	$ 782,960	$ 822,922	$ 847,950	$ 872,387	$ 878,222	$ 917,680	$ 1,026,212
GS>50	Fixed Rate	$ 160.00	$ 162.08	$ 165.00	$ 167.64	$ 169.15	$ 171.43	$ 174.60	$ 177.39	$ 182.18	$ 187.83	$ 223.00
	Variable Rate	$ 2.1482	$ 2.1761	$ 2.2153	$ 2.2507	$ 2.2710	$ 2.3017	$ 2.3443	$ 2.3818	$ 2.4461	$ 2.5219	$ 2.9381
	Customers	137	138	141	132	134	132	124	124	125	126	126
	kWh	125,765,970	130,146,426	130,517,952	131,013,598	134,083,745	133,361,535	129,723,990	135,353,629	142,708,632	136,085,199	139,510,255
	Revenues	$ 816,710	$ 826,561	$ 888,196	$ 870,180	$ 857,752	$ 868,499	$ 836,472	$ 878,648	$ 966,947	$ 952,475	$ 1,162,982
Sentinel Lights	Fixed Rate	$ 3.12	$ 3.16	$ 3.22	$ 3.27	$ 3.30	$ 3.34	$ 3.40	$ 3.45	$ 3.54	$ 3.65	$ 5.89
	Variable Rate	$ 12.1717	$ 12.3299	$ 12.5518	$ 12.7526	$ 12.8674	$ 13.0411	$ 13.2824	$ 13.4949	$ 13.8593	$ 14.2889	$ 23.0559
	Connections	141	151	152	151	155	157	158	158	157	157	158
	kWh	108,113	108,886	110,643	108,354	107,351	107,697	107,698	107,404	104,541	106,427	104,420
	Revenues	$ 7,254	$ 7,339	$ 8,482	$ 8,096	$ 8,362	$ 8,480	$ 9,298	$ 10,573	$ 10,455	$ 10,939	$ 17,536
Streetlights	Fixed Rate	$ 1.42	$ 1.44	$ 1.47	$ 1.49	$ 1.50	$ 1.52	$ 1.55	$ 1.57	$ 1.61	$ 1.66	$ 1.89
	Variable Rate	$ 7.8391	$ 7.9410	$ 8.0839	$ 8.2132	$ 8.2871	$ 8.3990	$ 8.5544	$ 8.6913	$ 8.9260	$ 9.2027	$ 10.4767
	Connections	2,915	2,851	2,845	2,890	2,939	2939	2962	2982	2,985	2,957	3,015
	kWh	1,920,607	1,750,885	933,500	904,819	912,796	925,959	924,100	911,971	917,094	916,560	923,583
	Revenues	$ 91,595	$ 91,113	$ 53,288	$ 71,690	$ 73,088	$ 74,656	$ 87,468	$ 77,905	$ 87,657	$ 81,315	$ 94,158
USL	Fixed Rate	$ 5.95	$ 6.03	$ 6.14	$ 6.24	$ 6.30	$ 6.39	$ 6.51	$ 6.61	$ 6.79	$ 7.00	$ 7.97
	Variable Rate	$ 0.0083	$ 0.0084	$ 0.0086	$ 0.0087	$ 0.0088	$ 0.0089	$ 0.0091	$ 0.0092	$ 0.0094	$ 0.0097	$ 0.0110
	Connections	73	96	97	97	97	97	97	98	98	98	97
	kWh	404,627	400,512	370,442	398,917	393,393	393,393	393,393	393,393	393,393	393,393	387,304
	Revenues	$ 10,158	$ 10,401	$ 10,939	$ 10,928	$ 40,430	$ 10,787	$ 11,076	$ 11,603	$ 10,993	$ 11,430	$ 13,346
TOTAL	kWh	254,199,128	256,505,459	256,407,308	256,379,985	269,097,947	264,882,097	266,581,177	271,553,035	281,013,371	274,973,841	274,586,366
	Revenues	$ 4,908,779	$ 4,777,622	$ 4,927,421	$ 5,232,741	$ 5,364,768	$ 5,416,469	$ 5,549,565	$ 5,740,311	$ 5,647,959	$ 6,077,967	$ 6,931,560

TABLE 10: HISTORICAL DISTRIBUTION REVENUE PER CUSTOMER



BILL IMPACTS

Since our last Cost of Service for 2014 rates, Orangeville Hydro's residential rate increases excluding rate riders have been near or below the rate of inflation. The transition to a fully fixed residential service charge has helped to ensure a stable source of revenue for Orangeville Hydro as well as ensuring more consistency for our residential customers' energy costs. Overall residential bill impacts include rate riders, which are in place for the recovery of deferral and variance accounts from pass through charges (regulatory assets and liabilities). Orangeville Hydro did not dispose of all deferral and variance accounts in 2019 and 2020, which is why there is a larger bill impact in 2021 including rate riders, as these rates included dispositions for multiple years.

TABLE 11: RESIDENTIAL BILL IMPACTS (DISTRIBUTION ONLY)

		Excluding Rate Riders (incl. SME charge)							
		2017	2018	2019	November 1, 2020	2021	November 1, 2021	2022	2023
Residential	Fixed Rate	$ 21.79	$ 24.29	$ 27.19	$ 27.92	28.35	28.11	28.85	29.58
	Variable Rate	$ 0.0069	$ 0.0035	$ -	$ -	$ -			
	Total (700 kWh)	$ 26.62	$ 26.74	$ 27.19	$ 27.92	$ 28.35	$ 28.11	$ 28.85	$ 29.58
	Bill Impact	1.9%	0.5%	1.7%	2.7%	1.5%	-0.8%	2.6%	2.5%
		Including Rate Riders							
		2017	2018	2019	November 1, 2020	2021	November 1, 2021	2022	2023
Residential	Fixed Rate	$ 21.96	$ 24.46	$ 27.35	$ 28.08	28.67	28.27	29.01	29.66
	Variable Rate	$ 0.0064	$ 0.0031	$ 0.0011	$ 0.0011	$ 0.0094	$ 0.0083	0.0039	0.0047
	Total (700 kWh)	$ 26.44	$ 26.63	$ 28.12	$ 28.85	$ 35.25	$ 34.08	$ 31.74	$ 32.95
	Bill Impact	-3.3%	0.7%	5.6%	2.6%	22.2%	-3.3%	-6.9%	3.8%

8. CAPITAL SPENDING

KEY OBJECTIVES FOR CAPITAL EXPENDITURE

The key objectives for Orangeville Hydro's capital expenditures over the next five years include:

- Ensuring our existing and future customers enjoy the benefit of a safe and reliable distribution system,
- Ensuring our staff can work safely on and near the distribution system,
- Mitigating the inherent risks of a distribution system through an effective asset management program,
- Understanding customer preferences – how our customers wish to receive service and how do they wish to interact with the utility to obtain the information they require and understand the goals, objectives, and priorities of the utility,
- Ensuring our load, generation, and storage customers have access to the distribution system as well as a long-term secure supply of energy, and
- Ensuring all regulatory compliance obligations are achieved.

System access expenditures for 2023 to 2028 are expected to be higher than the historical average of 2014 to 2022. System Access projects encompass customer requests for service connections and subdivisions. Growth will occur from new subdivisions, infill developments, and intensification developments. Considering these expenditures are based on customer demand, this forecast is subject to change.

System renewal expenditures for 2023 to 2028 are expected to be higher than the historical average of 2014 to 2022. These expenditures are to improve the distribution system by either replacing assets or extending the original service life of the major assets such as poles, transformers, switches, switching cubicles, and revenue meters. Considering these expenditures can be affected by the quantity of major assets that fail in a specific year, this forecast is subject to change.

System service expenditures for 2023 to 2028 are expected to be higher than the historical average of 2014 to 2022. These projects are planned to ensure the distribution system continues to meet operational objectives, while addressing future needs. The expenditures within this 5-year plan are significantly driven by Orangeville Hydro's voltage conversion program.

General Plant expenditures for 2023 to 2028 are expected to be higher than the historical average of 2014 to 2022. General Plant expenditures are for non-distribution assets, such as land, building, office equipment, computer hardware, vehicles, and small equipment. Intangibles are included in General Plant and include land rights and computer software.

2024 CAPITAL BUDGET

Description	2024 Budget	2023 Budget	Variance 2024 Budget to 2023 Budget	2023 Forecast	Variance 2023 Forecast to 2023 Budget	2022 Actuals	Variance 2024 Budget to 2022 Actuals
System Access	1,359,889	705,774	654,116	820,036	114,262	96,413	1,263,476
System Renewal	787,454	407,649	379,805	583,184	175,535	554,050	233,403
System Service	818,940	784,604	34,336	976,919	192,315	2,197,624	(1,378,684)
General Plant	710,917	288,898	422,019	124,383	(164,515)	134,922	575,995
Total Gross expenditures	**3,677,200**	**2,186,925**	**1,490,275**	**2,504,522**	**317,597**	**2,983,010**	**694,190**
Contributed Capital	(718,936)	(330,098)	(388,838)	(451,067)	(120,969)	(62,566)	(656,370)
Total net expenditures	**$ 2,958,264**	**$ 1,856,827**	**$ 1,101,437**	**$ 2,053,455**	**$ 196,628**	**$ 2,920,445**	**$ 37,819**

Capital investments are necessary to ensure a safe and reliable distribution system and to meet our obligation to connect new customers. It is important to Orangeville Hydro that there is a strong understanding of the entire system to determine priority assets that require replacement or repair.

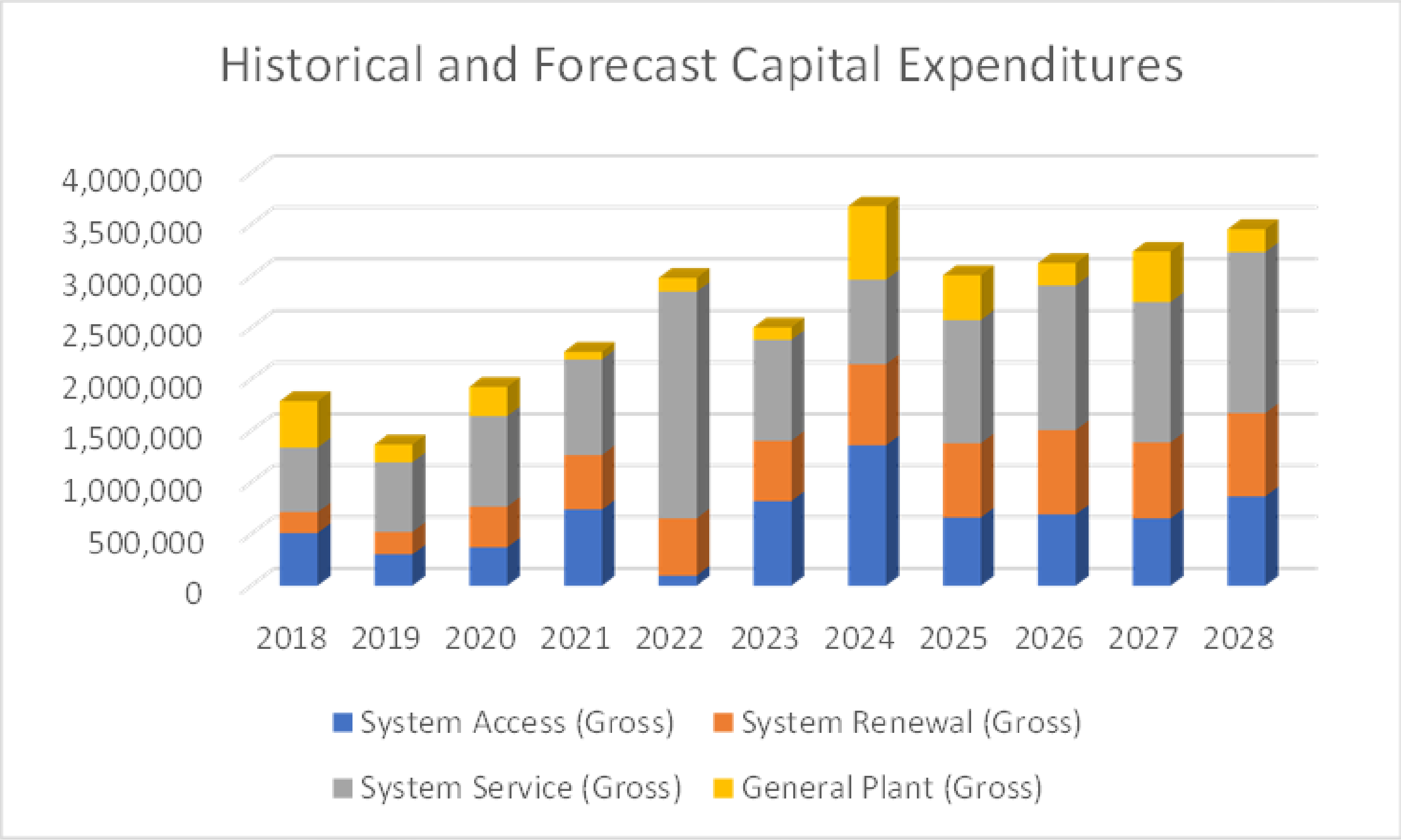
The 2024 Capital Budget of $2,958,264 includes the completion of three significant System Service projects, which are: B121 - MS2 East Feeder Voltage Conversion-Maple/Madison Ave, B122 - MS2 South Feeder Voltage Conversion-Edelwild/Rustic/Cedar/Lawrence, and B2024-1-2024 Ontario and Victoria St Voltage Conversion. These projects are the continuation of Orangeville Hydro voltage conversion program. The System Renewal projects of $787,454 are planned transformer, hardware, meter, and pole replacements. Meter replacements and additions are higher than historical with new meters for connecting new customers, to renew aging meter population, and utilize cellular infrastructure to improve reading reliability. Significant System Access costs of $1,359,889 are mainly attributed to the connection of two new residential subdivisions, which have both advised they will be connected within 2024. The 2024 General Plant Budget of $710,917 includes a roof replacement of the office portion of the building. It was recommended that the roof should be replaced over the course of 2024 and 2025, so the total expense has been split over two years. This budget also includes billing system upgrades, and the installation of an improved customer portal. A new GIS system installation is also included, which will provide improved asset management processes and improved system performance tracking for reporting purposes. A new electric truck to replace truck #34 is included, based on the Orangeville Hydro vehicle replacement policy. Throughout 2022 and 2023, significant price increases have been realized on major capital items; this budget has incorporated the known increases.

2024 CAPITAL BUDGET BY CATEGORY

Category	Reference Number	Project Description	Total Project	Contributed Capital
System Access	C01-2024	Various General Service Capital Contribution Projects	80,000	(40,000)
System Access	C02-2024	Various Residential Capital Contribution Projects	30,000	(25,000)
System Access	F01-2024	Estimated Distributed Energy Resources	8,000	(8,000)
System Access	S01-2024	Various Subdivisions	1,241,889	(645,936)
System Access Total:			**$1,359,889**	**$ (718,936)**
System Renewal	B83-2024	Substation Renewal	7,194	
System Renewal	TX-2024	Transformer and PME Renewal	161,383	
System Renewal	H00-2024	Hardware Replacement	50,000	
System Renewal	H00-SLEEVE-2024	Hardware Replacement - Automatic Sleeve Replacement	177,478	
System Renewal	M-2024	Meter Renewal	243,499	
System Renewal	P00-2024	Pole Replacement	147,900	
System Renewal Total:			**$ 787,454**	
System Service	B121-2024	MS2 East Feeder Voltage Conversion-Maple/Madison Ave	419,902	
System Service	B122-2024	MS2 South Feeder Voltage Conversion-Edelwild/Rustic/Cedar/Lawrence	209,941	
System Service	B2024-1-2024	Ontario and Victoria Street Voltage Conversion	189,097	
System Service Total:			**$ 818,940**	
General Plant	GP 2024 - 1	Building	296,000	
General Plant	GP 2024 - 2	Office Equipment	30,000	
General Plant	GP 2024 - 3	Computer Equipment	58,000	
General Plant	GP 2024 - 4	Computer Software	197,380	
General Plant	GP 2024 - 5	Vehicles	93,815	
General Plant	GP 2024 - 6	Stores Equipment	2,000	
General Plant	GP 2024 - 7	Tools, Shop & Garage Equipment	6,500	
General Plant	GP 2024 - 8	Measurement & Testing	24,222	
General Plant	GP 2024 - 9	Miscellaneous Equipment	2,000	
General Plant	GP 2024 - 10	Land Rights	-	
General Plant	GP 2024 - 11	Communication Equipment	1,000	
General Plant Total:			**$ 710,917**	
Total 2024 Budget Capital Expenditures			**$3,677,200**	**$ (718,936)**
Total 2024 Budget Capital Expenditures Less Contributed Capital			**$2,958,264**	

2024-2028 CAPITAL EXPENDITURE PLAN

TABLE 12: CAPITAL EXPENDITURES BY YEAR AND TYPE



Orangeville Hydro is required to submit a periodic Distribution System Plan (DSP), typically along with a Cost of Service rate application. This DSP is designed to present Orangeville Hydro's fully integrated approach to capital expenditure planning. This includes comprehensive documentation of its Asset Management process that supports its future five-year capital expenditure plan while assessing the performance of its historical five-year period.

The electricity distribution system is capital intensive in nature and prudent capital investments and maintenance plans are essential to ensure the sustainability of the distribution network. Orangeville Hydro's DSP documents the practices, policies and processes that are in place to ensure decisions on capital investments and maintenance plans support Orangeville Hydro's desired outcomes cost-effectively and provides value to customers.

In every year of the DSP, a comprehensive capital plan is completed, which includes System Access capital contribution jobs, System Service conversion projects, System Renewal upgrade projects, and General Plant expenditures.

TABLE 13: SUMMARY OF HISTORICAL AND PLAN CAPITAL EXPENDITURES 2018–2028

Category	Historical						Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
System Access (Gross)	509,508	302,685	372,926	736,527	96,413	820,036	1,359,889	658,682	688,513	650,310	865,968
System Renewal (Gross)	201,614	217,629	394,476	530,019	554,050	583,184	787,454	720,928	816,933	737,671	807,351
System Service (Gross)	625,952	676,650	877,012	925,386	2,197,624	976,919	818,940	1,194,177	1,405,127	1,359,250	1,557,016
General Plant (Gross)	450,696	171,264	280,525	73,302	134,922	124,383	710,917	436,000	215,000	490,000	225,000
Gross Capital Expenses	1,787,770	1,368,228	1,924,939	2,265,234	2,983,009	2,504,522	3,677,200	3,009,787	3,125,572	3,237,231	3,455,335
Contributed Capital	(198,868)	(114,921)	(239,979)	(349,139)	(62,566)	(451,067)	(718,936)	(203,666)	(377,697)	(291,859)	(372,702)
Net Capital Expenses after Contributions	1,588,902	1,253,307	1,684,960	1,916,095	2,920,443	2,053,455	2,958,264	2,806,121	2,747,875	2,945,372	3,082,633
System O&M	754,878	958,991	807,988	1,077,960	1,164,462	1,249,459	1,359,282	1,393,264	1,379,096	1,169,562	1,198,802

Details of major projects each year are below:

2024 System Service projects include:
• B121 – MS2 East Feeder Voltage Conversion-Maple, Madison Ave
• B122 – MS2 South Feeder Voltage Conversion-Edelwild/Rustic/Cedar/Lawrence
• B2024-1-2024 – Ontario and Victoria Street Voltage Conversion
Significant roof upgrades at 400 C Line office area are included in the General Plant budget, as well as a new Electric Pickup Truck.

2025 System Service projects include:
• B119 – Blind Line Primary Conductor Upgrade-Broadway to Hansen
• B123 – Voltage Conversion from Rabbit-Cardwell-Dufferin-Ontario-Caledonia
• B124 – MS2 East Feeder Conversion-Carlton-Lawrence
Significant roof upgrades at 400 C Line garage area are included in the General Plant budget, as well as a new pickup truck.

2026 System Service projects include:
• B125 – MS3 North Feeder – Broadway-Banting-Zina-Elizabeth-Birch Conversion
• B126 – MS4 West Feeder – Amelia St-Jackson Court Voltage Conversion
A new Electric vehicle pickup truck replacement is included in the General Plant budget.

2027 System Service projects include:
• B127 – MS4 West Feeder – Westmorland-Fairview, Elm Voltage Conversion
• B128 – MS4 West Feeder – Meadow, Passmore, Pheasant Dr Voltage Conversion
A double bucket truck replacement is included in the General Plant budget, as well as a replacement pickup truck.

2028 System Service projects include:
• B128 – Continuation of MS4 West Feeder – Meadow, Passmore, Pheasant Dr Voltage Conversion
• B129 – MS4 West Feeder – Kensington Place Voltage Conversion
• BRAB – Voltage Conversion of Rabbits (Crimson, Orangemill Court, Quarry, Sherbourne)
A dump truck replacement is included in the General Plant budget.

9. OPERATING COSTS

Operating and maintenance work will maintain the focus on inspecting, testing, patrolling as well as the supervision of the distribution system and equipment such as sub-stations, transformers, and meters, along with engineering and mapping expenses. It also includes planned maintenance projects such as vegetation management in problem areas plus any costs that are a result of reactive work that occurs, such as repairing transformers and trouble calls. A well-maintained distribution system results in better system reliability which is one of our major initiatives. The Operating budget includes labour, material, and contractor costs.

Billing, Collecting and Meter Reading budget includes an allocated portion of the salary for the Manager of Customer Service to oversee the customer service department, customer service staff labour and benefits, stationery, postage, and billing system operating costs along with meter reading and smart metering costs. While our focus remains on the customer, Orangeville Hydro is always investigating efficiencies and striving to reduce costs.

The Community Relations budget covers our safety and conservation programs for 2 schools each year to educate students on either conservation or electrical safety. This budget also includes "On hold" informational messages to our customers, radio advertising and participation in local events, such as Christmas in the Park, Customer Education Day, Grand Valley Duck Race, and the Orangeville Farmers market.

Administration is an integral part of our business plan. This category budget includes costs for the Directors, President, and Chief Financial Officer, as well as finance and regulatory staff. Labour, benefits, training, conferences, office maintenance and supplies, and insurances for property and liability, Ontario Energy Board regulatory costs, association memberships, HR, legal and auditing consultants, and a portion of the IT consultant are some of the other costs that drive the Administration budget. Orangeville Hydro will continue its membership in the Cornerstone Hydro Electric Concepts Co-operative (CHEC) as the membership translates into valuable collaboration cost savings. Membership in Utilities Standards Forum (USF) is extremely beneficial in providing engineering standards common to the entire industry, as well as regulatory and customer service networking between other local distribution companies. Membership in the Electricity Distributors Association (EDA) is also valuable with the association being the voice for Ontario's electricity distributors.

2024 OPERATIONS, MAINTENANCE, AND ADMINISTRATION BUDGET

Description	2024 Budget	2023 Budget	Variance 2024 Budget to 2023 Budget	2023 Forecast	Variance 2023 Forecast to 2023 Budget	2022 Actuals	Variance 2024 Budget to to 2022 Actuals
Operating	1,008,856	892,650	116,205	876,770	(15,881)	797,113	211,743
Maintenance	350,426	324,805	25,622	372,689	47,884	367,349	(16,923)
Distribution	**1,359,286**	**1,217,459**	**141,827**	**1,249,459**	**32,000**	**1,164,462**	**194,824**
Billing & Collecting	**1,191,556**	**1,098,800**	**92,756**	**1,074,172**	**(24,628)**	**983,094**	208,462
Community Relations	**61,354**	**55,210**	**6,144**	**51,171**	**(4,039)**	**32,446**	28,908
Administration	**1,672,500**	**1,466,009**	**206,491**	**1,485,901**	**19,893**	**1,506,086**	166,414
Total	**$ 4,284,697**	**$ 3,837,479**	**$ 447,219**	**$ 3,860,703**	**$ 23,226**	**$ 3,686,088**	**$ 598,609**
Total Percentage Variance			**11.7%**		**0.61%**		**16.24%**

Overall, the 2024 OM&A Expenses Budget of $4,284,697, is $598,609 higher than the 2022 Actuals of $3,686,088 due to the expenditures described below.

Salaries and wages are a significant aspect of the OM&A expenses, and Orangeville Hydro recognizes the value of a skilled and customer focused workforce. Orangeville Hydro is conscious of the importance of prudent operational spending and completes a monthly analysis to ensure actual spending is close to budgeted costs. All areas of this budget include regular and performance-based salary progressions as well as benefit rate increases over 2022. Management attempts to find efficiencies to reduce OM&A spending where possible. Inflationary increases have been incorporated into the 2024 budget, as there have been widespread increases on many items throughout the budget.

DISTRIBUTION

This Operating and Maintenance budget will maintain the focus on inspecting, testing, patrolling as well as the supervision of the distribution system and equipment such as sub-stations, transformers, and meters, along with engineering and mapping expenses. It also includes planned maintenance projects such as vegetation management in problem areas plus any costs that are a result of reactive work that occurs, such as repairing transformers and trouble calls. A well-maintained distribution system results in better system reliability which is one of our major initiatives.

The 2024 Distribution Budget is higher than the 2022 Actuals with an increase of $194,824. This increase is mainly due to an additional staff member in the Engineering department to meet customers' expectations for service connections and upgrades as well as planning for capital and maintenance programs. The 2024 budget includes higher contractor costs to complete underground locates, to try and ensure we remain in compliance with Ontario One Call regulations as well as customer requested Disconnect/Reconnects. It also includes a third of the overall IT contractor costs, and additional GIS monthly costs.

BILLING, COLLECTING AND METER READING

The 2024 Billing and Collecting Budget is higher than the 2022 Actuals by $208,462. The increase mainly due to an increase in many of the contract costs, such as outsourced meter reading, sync operator, bill printing and CIS monthly costs. There is an increase in labour costs with a reallocation between electric and water accounts. The budget includes higher training and conference costs as compared to 2022, and salary progressions for newer customer service staff. The monthly maintenance costs of the improved customer portal have increased significantly and there is an increase in bad debt in the 2024 budget, as compared to 2022 actuals.

COMMUNITY RELATIONS

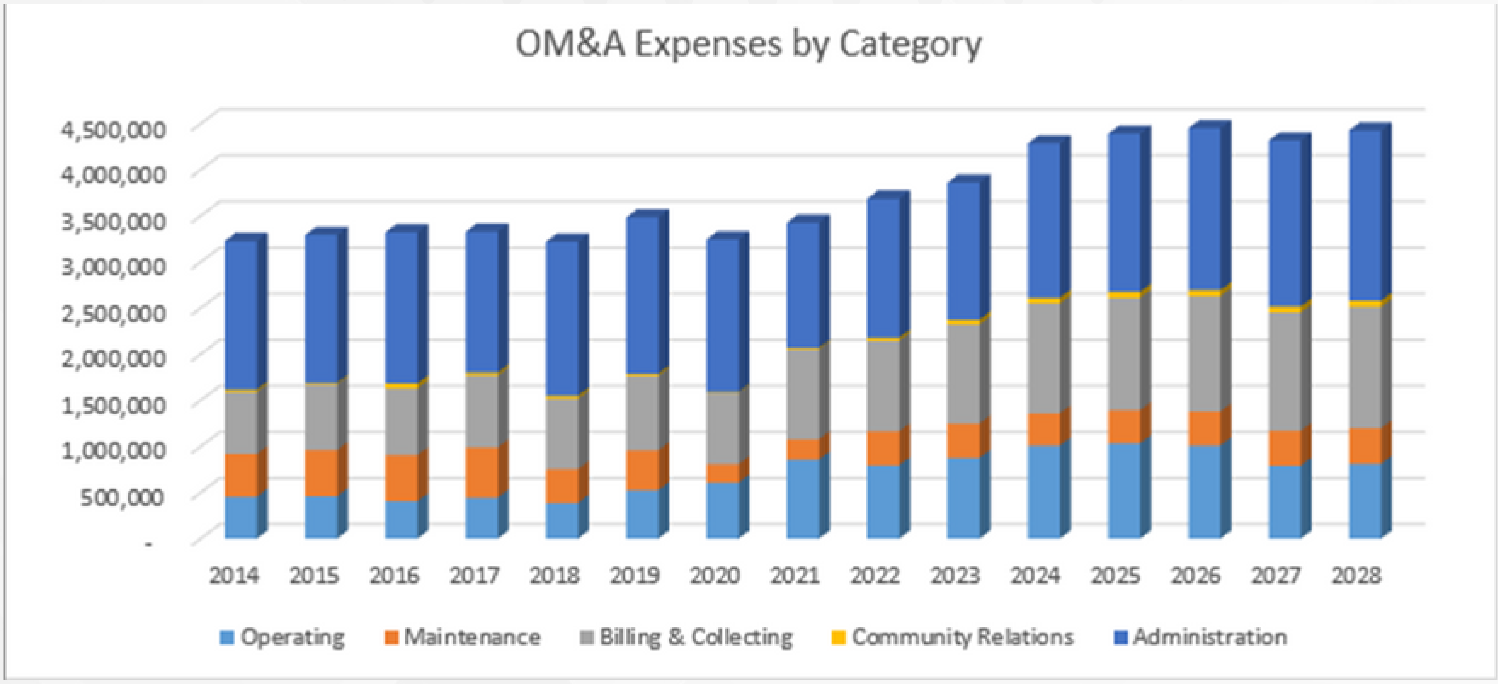
The 2024 Community Relations Budget is higher than the 2022 Actuals by $28,908. The budget includes four planned community engagement events, as well as an increase in the percentage of the Marketing and Communications Coordinators' time, which accounts for most of the increase over 2022 actuals.

ADMINISTRATION

The 2024 Administration Budget is $166,414 higher than the 2022 Actuals. It includes an increase in insurance expenses, as well as training and conference costs for the executive staff, finance and board members. There is an increase of HR assistance costs, as well as net zero consultant costs to move us closer to our net zero goals within our strategic plan. A fifth of the estimated expenses that will be incurred to complete the cost of service application for the OEB are included in this budget.

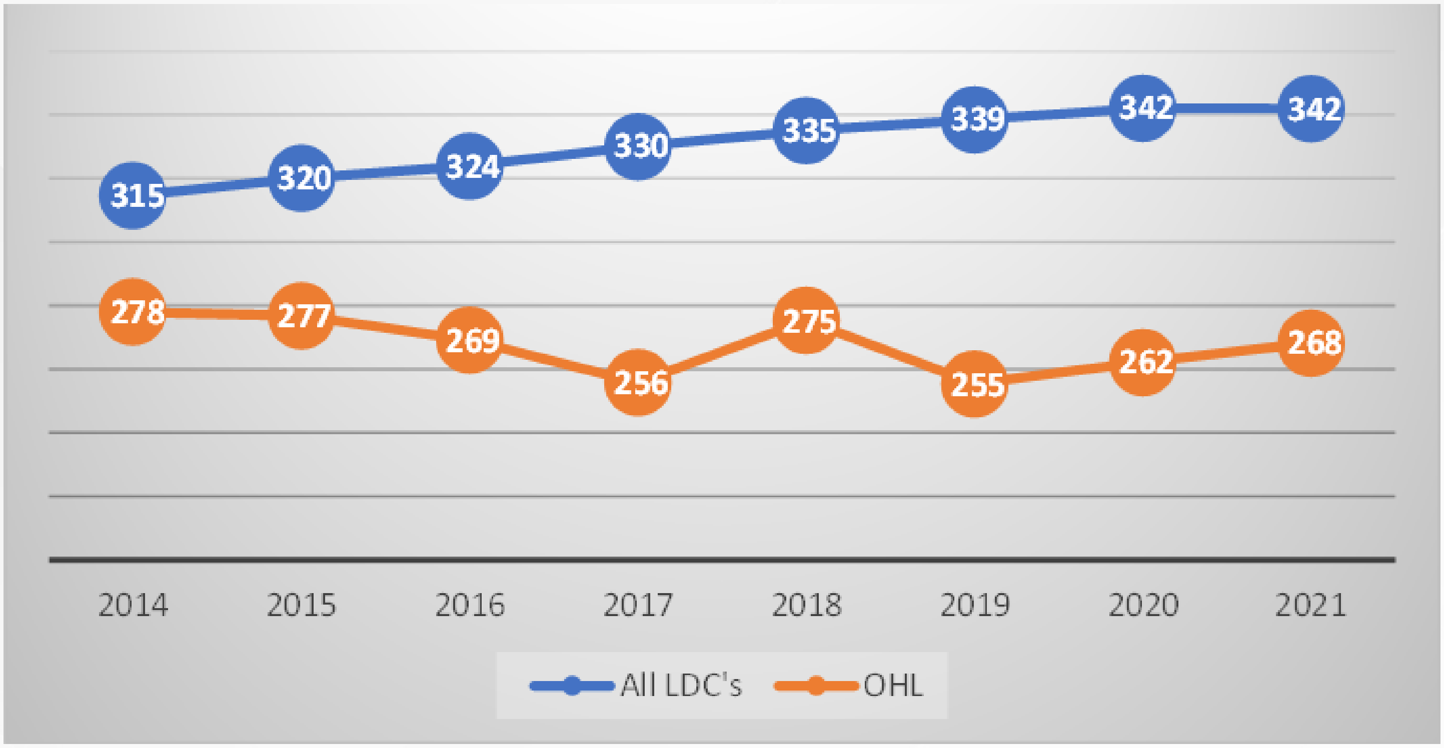
2024-2028 OPERATING, MAINTENANCE, AND ADMINISTRATION EXPENDITURE PLAN

TABLE 14: OM&A EXPENSES BY YEAR AND TYPE



In the forecast from 2024 to 2028, an increase in most operating costs of a rate of 3% per year was used. After an increase of one staff member in 2023, the headcount remains at a steady level of 20 full-time employees going forward. Salaries and wages are a significant aspect of the OM&A expenses, and Orangeville Hydro recognizes the value of a skilled and customer focused workforce. Orangeville Hydro is conscious of the importance of prudent operational spending and completes a monthly analysis to ensure actual spending is close to budgeted costs. Management attempts to find ways to reduce OM&A spending where possible.
Orangeville Hydro's OM&A costs per customer historically is consistently lower than province-wide costs per customer. This is due to a steadily increasing customer base and OM&A expenses staying at fairly consistent levels.

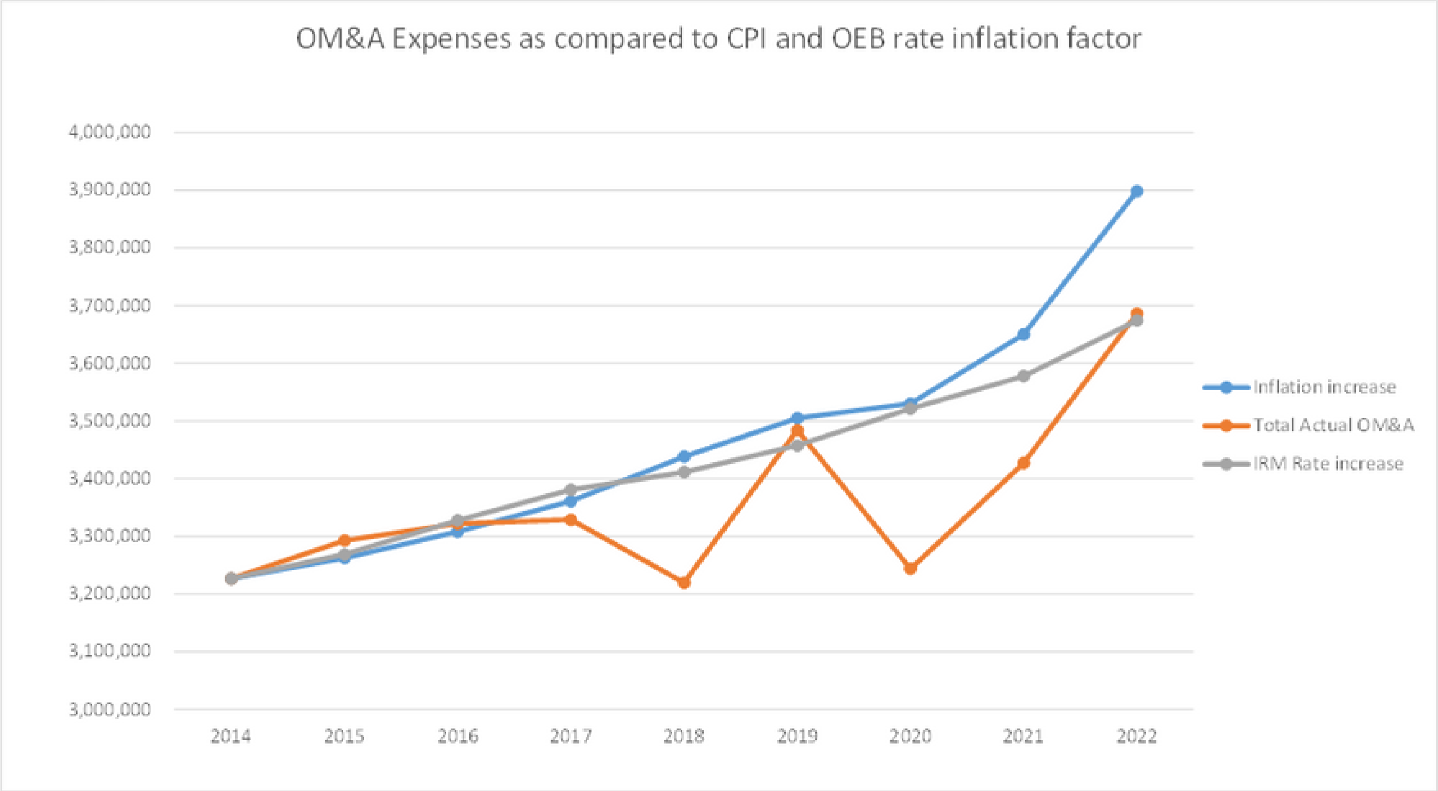
TABLE 15: OM&A COSTS PER CUSTOMER



OM&A COSTS AS COMPARED TO CPI AND OEB INFLATION FACTOR INCREASES

Orangeville Hydro compared its OM&A costs per customer from 2014 to 2022, as compared to historical Canada CPI rates and the OEB IRM rate increases every year, also per customer. With a base year of 2014, OM&A fluctuates more significantly than CPI or OEB inflation factors, but overall has been consistently lower than both metrics.

TABLE 16: OM&A AS COMPARED TO CPI AND OEB INFLATION FACTOR PER CUSTOMER

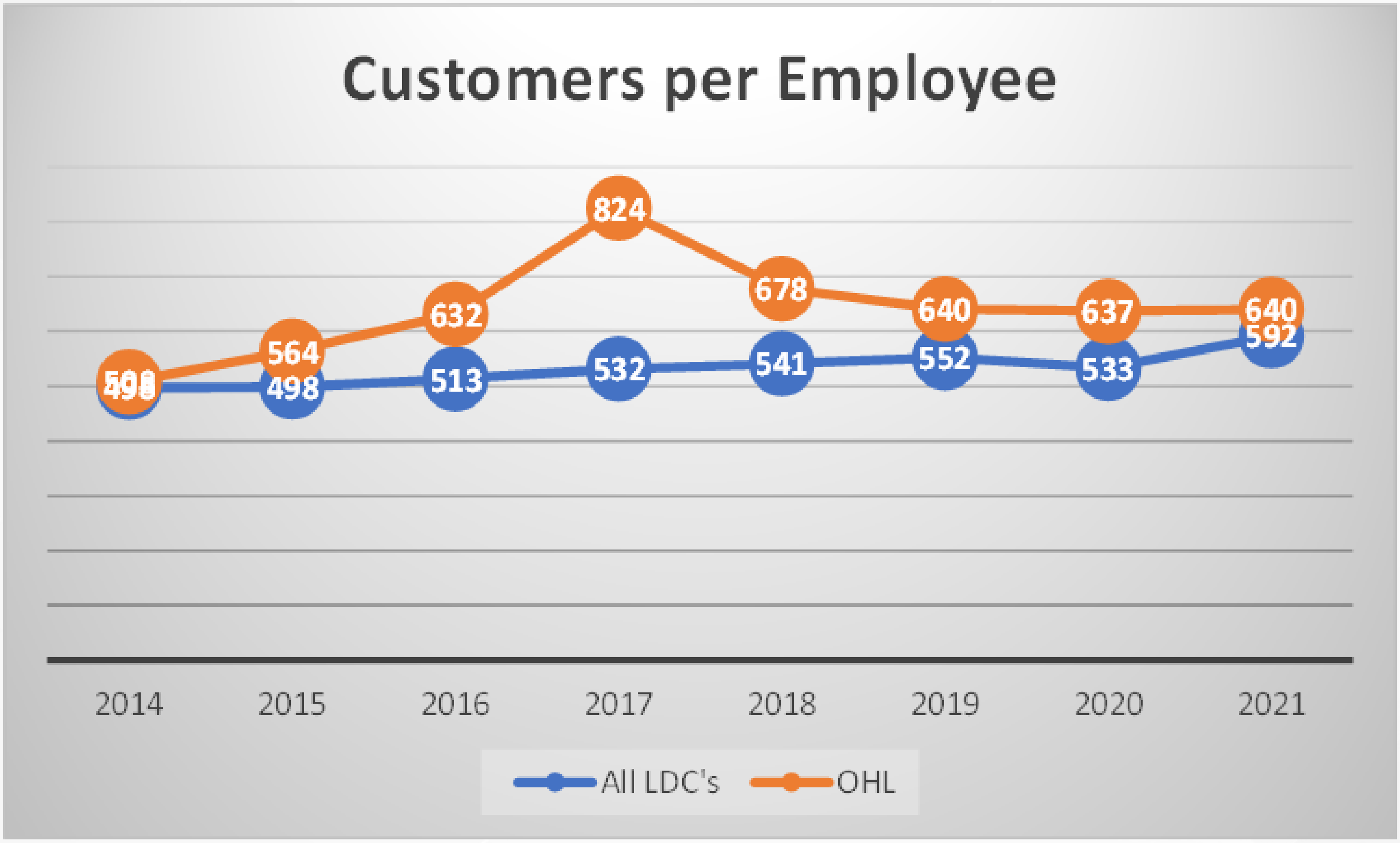


10. PERSONNEL

Orangeville Hydro operates its business with a lean number of employees. This is proven through a comparison of Orangeville Hydro's number of customers per employee compared to other LDCs in Ontario. The efficiency is achieved through ensuring our employees are highly skilled and trained, as well as collaborating with other LDCs through CHEC, UCS, USF, and EDA.

By the end of 2023, the full-time staff complement is expected to be 20. This number of employees is expected to remain consistent for the near future.

TABLE 17: CUSTOMERS PER EMPLOYEE



11. FINANCIAL SUMMARY

TABLE 18: HISTORICAL FINANCIAL SUMMARY AND STATISTICS

	Financial Summary								
	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Energy Sales	$ 26,720,348	$ 29,637,637	$ 33,499,518	$ 30,048,911	$ 28,491,290	$ 29,164,689	$ 33,148,280	$ 30,406,079	$ 31,873,671
Distribution Revenue	$ 4,954,958	$ 4,839,850	$ 5,200,350	$ 5,219,614	$ 5,444,878	$ 5,674,628	$ 5,664,418	$ 5,796,532	$ 5,640,664
OM&A Expenses	$ 3,226,833	$ 3,292,572	$ 3,322,207	$ 3,328,900	$ 3,219,669	$ 3,492,710	$ 3,285,656	$ 3,426,889	$ 3,686,088
Capital Expenditures	$ 2,167,163	$ 1,293,107	$ 1,940,991	$ 2,551,610	$ 1,778,360	$ 1,368,228	$ 1,924,938	$ 2,265,235	$ 2,983,010
Net Income	$ 712,039	$ 549,640	$ 742,839	$ 1,070,150	$ 1,132,870	$ 901,542	$ 1,086,517	$ 908,964	$ 747,579
Shareholder Equity	$ 9,261,741	$ 9,508,537	$ 9,865,747	$ 10,289,603	$ 10,994,887	$ 11,329,992	$ 11,965,738	$ 12,331,443	$ 12,593,355
Total Debt	$ 11,303,321	$ 10,910,584	$ 10,505,200	$ 12,043,169	$ 11,554,844	$ 13,009,817	$ 13,418,780	$ 13,805,822	$ 16,131,609
Capital assets (PP&E)	$ 17,089,439	$ 17,320,291	$ 18,337,875	$ 19,850,847	$ 20,620,014	$ 20,934,988	$ 21,786,371	$ 22,952,526	$ 24,798,238
Annual Dividends to Shareholders	$ 423,796	$ 302,844	$ 385,629	$ 646,294	$ 447,092	$ 566,435	$ 450,771	$ 543,259	$ 485,664
Cumulative Dividends Paid	$ 17,889,288	$ 18,192,132	$ 18,577,761	$ 19,224,055	$ 19,671,147	$ 20,237,582	$ 20,688,353	$ 21,231,611	$ 21,717,275
Number of customers	11,757	11,934	12,000	12,462	12,690	12,766	12,808	12,885	12,956
Number of employees (incl part tir	23	21	19	15	19	20	20	20	21

	Financial Statistics								
	2014	2015	2016	2017	2018	2019	2020	2021	2022
	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Actual
Return on Equity (Financials)	7.69%	5.78%	7.53%	10.40%	10.30%	7.96%	9.08%	7.37%	5.94%
Return on Equity (Regulated)	9.47%	6.40%	8.68%	10.60%	11.92%	10.34%	11.83%	9.46%	5.71%
Debt %	55%	53%	52%	54%	51%	53%	53%	53%	56%
Equity %	45%	47%	48%	46%	49%	47%	47%	47%	44%
Debt to Equity	1.21	1.15	1.06	1.17	1.05	1.15	1.12	1.12	1.28
Debt to Assets %	41%	38%	36%	37%	38%	41%	39%	39%	41%
Debt to Capital Assets %	66%	63%	57%	61%	56%	62%	62%	60%	65%
OM&A expenses/customer	$ 274	$ 276	$ 277	$ 267	$ 254	$ 274	$ 257	$ 266	$ 285
Customers/Employee	511	568	632	831	668	646	642	646	617

TABLE 19: FORECAST FINANCIAL SUMMARY AND STATISTICS

	Financial Summary					
	2023	2024	2025	2026	2027	2028
	Plan	Plan	Plan	Plan	Plan	Plan
Energy Sales	$ 30,366,687	$ 30,678,136	$ 30,452,523	$ 30,256,615	$ 30,899,134	$ 31,604,994
Distribution Revenue	$ 6,077,967	$ 6,931,560	$ 7,070,191	$ 7,211,595	$ 7,355,827	$ 7,502,943
OM&A Expenses	$ 3,860,703	$ 4,284,693	$ 4,390,377	$ 4,450,807	$ 4,317,738	$ 4,425,352
Capital Expenditures	$ 2,469,455	$ 3,677,200	$ 3,009,787	$ 3,125,572	$ 3,237,231	$ 3,455,335
Net Income	$ 867,118	$ 981,714	$ 889,078	$ 898,038	$ 1,082,842	$ 994,497
Shareholder Equity	$ 13,086,683	$ 13,634,838	$ 14,033,059	$ 14,486,558	$ 15,120,381	$ 15,573,457
Total Debt	$ 15,586,123	$ 16,554,270	$ 16,006,623	$ 18,409,818	$ 17,769,847	$ 19,589,132
Capital assets (PP&E)	$ 26,086,024	$ 28,496,700	$ 30,162,245	$ 31,928,042	$ 33,740,980	$ 35,668,661
Annual Dividends to Shareholders	$ 373,790	$ 433,559	$ 490,857	$ 444,539	$ 449,019	$ 541,421
Cumulative Dividends Paid	$ 22,091,065	$ 22,524,624	$ 23,015,481	$ 23,460,020	$ 23,909,039	$ 24,450,460
Number of customers	13,021	13,086	13,151	13,217	13,283	13,350
Number of employees (incl part tin	21	21	21	21	21	21
	Financial Statistics					
	2023	2024	2025	2026	2027	2028
	Plan	Plan	Plan	Plan	Plan	Plan
Return on Equity (Financials)	6.63%	7.20%	6.34%	6.20%	7.16%	6.39%
Return on Equity (Regulated)						
Debt %	54%	55%	53%	56%	54%	56%
Equity %	46%	45%	47%	44%	46%	44%
Debt to Equity	1.19	1.21	1.14	1.27	1.18	1.26
Debt to Assets %	41%	41%	40%	42%	41%	42%
Debt to Capital Assets %	60%	58%	53%	58%	53%	55%
OM&A expenses/customer	$ 297	$ 327	$ 334	$ 337	$ 325	$ 331
Customers/Employee	620	623	626	629	633	636

REVENUES

Energy Sales include the pass-through commodity costs and are budgeted to increase 2% year over year after 2024. The 2024 Energy Sales are budgeted to increase at the same level as Cost of Power expenses. Distribution revenue is budgeted in 2023 to increase by an estimated number of customers for most customer classes, and then increased in 2024 based on the forecasted revenue requirement. Future years are then conservatively increased by 2% to account for rate increases and customer growth. The residential service charge is now fully fixed, resulting in additional revenue stability in the future.

EXPENSES

The 2024 Cost of Power expenses, which offset the Energy Sales, are based on the Cost of Service models, which incorporate forecasted volumes and rates. Most OM&A expenses are expected to increase in 2023 by 3% and the remaining years by 2.5% to account for inflationary increases as well as additional cost increases, and wages for employees are planned to increase according to the projected Collective Agreement increases. Finance costs will increase due to the additional borrowing projected in 2024, 2026 and 2028.

CAPITAL STRUCTURE

In 2024, Orangeville Hydro projects borrowing $1.5 million to sustain our increased capital works plan and fund regulatory related payments, such as Hydro One low voltage (LV), network (NW), and connection (CN) charges and fluctuating Power and Global Adjustment rates. This will take the debt to equity ratio to 55:45, a small deviation from the OEB deemed structure of 60:40. The Business Plan calls for another $3 million increase in borrowing in 2026 and $2.5 million in 2028. Orangeville Hydro will utilize the borrowing to maintain investment in our infrastructure, progression of technologies, and manage our net regulatory assets.

RATES/RETURN

A comprehensive review by the OEB of Orangeville Hydro's operating, maintenance, and administration costs along with recovery of income taxes and capital investments in our distribution system was completed in 2014 and will take place again in 2024 through the cost of service rate application. Orangeville Hydro earns a return on these investments at the cost of capital rate as deemed by the OEB to meet a certain revenue requirement to develop our distribution rates. Orangeville Hydro rates are currently set to earn a return on equity of 9.36% and to recover the OM&A costs to operate the utility efficiently. When the next Cost of Service rate application is completed, this deemed ROE rate will change as determined by the OEB. The regulated ROE is based on the regulated net income divided by the total rate base, which is calculated as the average property, plant, and equipment plus working capital. During our yearly planning process, management is continuously examining improvements thus intent on achieving a reasonable return on equity.

DIVIDENDS

Historically Orangeville Hydro has provided special dividends to the shareholders in 2005, 2008, 2013 and 2017 amounting to $3.6 million. From 2000 to 2022, Orangeville Hydro has provided the Town of Orangeville with over $21.2 million in dividends and from 2007-2022 the Town of Grand Valley has received over $513,000 in dividends. In the 2024-2028 Business Plan there are no projected special dividends, although consideration over the plan years may be made. Over the horizon of this plan the dividends are estimated at an average of $470,000 per year to 2028. Cash position is constantly monitored with respect to our regulatory environment and vigilance is taken to ensure we can support our future capital requirements.

12. PRO-FORMA FINANCIAL STATEMENTS

ORANGEVILLE HYDRO LIMITED
Statement of Comprehensive Income
Year ended December 31

	2022 Actual	2023 Forecast	2024 Budget	2025 Plan	2026 Plan	2027 Plan	2028 Plan
Revenue							
Sale of energy	$ 31,873,671	$ 30,366,687	$ 30,678,136	$ 30,452,523	$ 30,256,615	$ 30,899,134	$ 31,604,994
Distribution revenue	5,640,664	6,077,967	6,931,560	7,070,191	7,211,595	7,355,827	7,502,943
Other	312,396	320,530	357,596	365,421	370,485	376,478	382,019
	5,953,060	**6,398,497**	**7,289,156**	**7,435,612**	**7,582,080**	**7,732,304**	**7,884,962**
Total revenues	37,826,731	36,765,184	37,967,291	37,888,135	37,838,696	38,631,439	39,489,957
Operating expenses							
Cost of power purchased	32,063,987	29,835,808	29,237,531	29,820,981	30,416,100	31,023,122	31,642,284
Operating and maintenance	1,164,462	1,249,459	1,359,282	1,393,264	1,379,096	1,169,562	1,198,802
Billing and collecting	1,003,017	1,074,172	1,191,556	1,220,241	1,250,747	1,282,016	1,314,066
Community relations		51,171	61,354	62,888	64,460	66,072	67,724
General and administrative	1,523,517	1,485,901	1,672,501	1,713,984	1,756,504	1,800,087	1,844,760
Loss on sale of property, plant and equipment and intangible assets	45,768						
Depreciation and Amortization	981,573	1,031,848	1,124,239	1,202,201	1,223,589	1,280,154	1,365,497
	4,718,337	**4,892,551**	**5,408,932**	**5,592,578**	**5,674,396**	**5,597,892**	**5,790,849**
Total expenses	**36,782,324**	**34,728,359**	**34,646,463**	**35,413,559**	**36,090,496**	**36,621,013**	**37,433,132**
Income from operating activities	**1,044,407**	**2,036,824**	**3,320,828**	**2,474,576**	**1,748,199**	**2,010,426**	**2,056,824**
Finance income	21,878	112,384	31,705	32,181	32,663	33,153	33,651
Finance costs	(553,390)	(677,498)	(746,210)	(773,390)	(819,932)	(843,483)	(897,452)
Income before income taxes	**512,895**	**1,471,710**	**2,606,324**	**1,733,367**	**960,930**	**1,200,095**	**1,193,023**
Income tax expense	(128,874)	(205,002)	(536,971)	(334,688)	(190,723)	(218,651)	(228,668)
Net income for the year	**384,021**	**1,266,708**	**2,069,353**	**1,398,679**	**770,207**	**981,444**	**964,355**
Other income (expenses)							
Net movement in regulatory balances	427,688	(530,878)	(1,440,605)	(631,542)	159,485	123,987	37,289
Tax on net movement	(64,130)	131,289	352,966	121,942	(31,654)	(22,590)	(7,147)
	363,558	**(399,590)**	**(1,087,639)**	**(509,601)**	**127,831**	**101,397**	**30,142**
Net income for the year and net movement in regulatory balances, being total comprehensive income	$ 747,579	$ 867,118	$ 981,714	$ 889,078	$ 898,038	$ 1,082,842	$ 994,497
Other comprehensive loss							
Remeasurements of post-employment benefits, net of tax	0						
Other comprehensive loss for the year	0						
Total income and other comprehensive income	747,579	867,118	981,714	889,078	898,038	1,082,842	994,497

ORANGEVILLE HYDRO LIMITED
Statement of Financial Position
December 31

	2022 Actual	2023 Forecast	2024 Budget	2025 Plan	2026 Plan	2027 Plan	2028 Plan
Assets							
Current assets							
Cash	$ 1,595,236	$ 685,286	$ 2,225,091	$ 1,121,346	$ 2,300,911	$ 512,358	$ 1,047,767
Accounts receivable	4,436,206	4,281,539	3,932,286	3,971,420	4,010,946	4,050,868	4,091,188
Income taxes receivable	172,933						
Unbilled revenue	3,241,571	3,273,986	3,306,726	3,339,793	3,373,191	3,406,923	3,440,992
Inventory	450,531	452,783	455,047	457,322	459,609	461,907	464,217
Prepaid expenses	167,392	169,066	170,756	172,464	174,188	175,930	177,690
Other	852	937	1,031	1,134	1,247	1,372	1,509
Total current assets	10,064,720	8,863,597	10,090,938	9,063,480	10,320,094	8,609,358	9,223,363
Non-current assets							
Property, plant and equipment	24,592,612	25,891,953	28,147,293	29,771,630	31,580,745	33,438,560	35,414,583
Intangible assets	205,626	194,071	349,407	390,615	347,297	302,420	254,078
Total non-current assets	24,798,238	26,086,024	28,496,700	30,162,245	31,928,042	33,740,980	35,668,661
Total assets	**34,862,958**	**34,949,622**	**38,587,637**	**39,225,725**	**42,248,136**	**42,350,338**	**44,892,023**
Regulatory debit balances	4,505,500	3,308,701	1,660,972	1,096,229	1,255,664	1,379,652	1,416,941
Total assets and regulatory balances	**$ 39,368,458**	**$ 38,258,323**	**$ 40,248,609**	**$ 40,321,955**	**$ 43,503,800**	**$ 43,729,990**	**$ 46,308,964**
Liabilities							
Current Liabilities							
Accounts payable and accrued liabilities	$ 6,334,443	$ 5,639,778	$ 5,694,103	$ 5,748,969	$ 5,805,603	$ 5,862,862	$ 5,920,756
Long-term debt due within one year	590,827	520,602	547,647	566,776	639,971	655,773	716,079
Customer deposits	200,000	201,000	202,005	203,015	204,030	205,050	206,076
Other payables	184,341	179,868	181,666	183,483	185,318	187,171	189,043
Income taxes payable		15,150	15,302	15,455	15,609	15,765	15,923
Total current liabilities	7,309,612	6,556,398	6,640,723	6,717,698	6,850,531	6,926,621	7,047,876
Non-Current Liabilities							
Long-term debt	15,540,781	15,065,520	16,006,623	15,439,846	17,769,847	17,114,074	18,873,053
Employee future benefits	434,474	443,078	451,682	460,286	468,890	477,494	486,098
Customer deposits	299,914	201,913	183,732	165,369	146,823	128,091	109,172
Contributions in aid of construction	2,317,945	2,696,516	3,329,922	3,437,806	3,713,261	3,895,439	4,151,419
Deferred tax liability	412,695	412,695	412,695	412,695	412,695	412,695	412,695
Total non-current liabilities	19,005,809	18,819,722	20,384,653	19,916,002	22,511,516	22,027,793	24,032,437
Total Liabilities	26,315,421	25,376,120	27,025,376	26,633,701	29,362,047	28,954,414	31,080,313
Equity							
Share capital	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714	8,290,714
Retained earnings	4,317,605	4,810,933	5,359,088	5,757,309	6,210,808	6,844,631	7,297,707
Accumulated other comprehensive income	(14,964)	(14,964)	(14,964)	(14,964)	(14,964)	(14,964)	(14,964)
Total equity	12,593,355	13,086,683	13,634,838	14,033,059	14,486,558	15,120,381	15,573,457
Total liabilities and equity	38,908,776	38,462,803	40,660,214	40,666,760	43,848,605	44,074,795	46,653,769
Regulatory credit balances	459,682	(204,483)	(411,608)	(344,808)	(344,808)	(344,808)	(344,808)
Total liabilities, equity and regulatory balances	**$ 39,368,457**	**$ 38,258,323**	**$ 40,248,609**	**$ 40,321,952**	**$ 43,503,797**	**$ 43,729,987**	**$ 46,308,961**

ORANGEVILLE HYDRO LIMITED
Statements of Cash Flows
Year ended December 31

	2022 Actual	2023 Forecast	2024 Budget	2025 Plan	2026 Plan	2027 Plan	2028 Plan
Operating activities							
Net income and net movement in regulatory balances	$ 747,579	$ 867,118	$ 981,714	$ 889,078	$ 898,038	$ 1,082,842	$ 994,497
Adjustments for:							
Depreciation and amortization	1,084,978	1,133,670	1,223,525	1,301,241	1,316,775	1,381,293	1,484,654
Loss on sale of property, plant and equipment and intangible assets	45,768	53,000	48,000	43,000	43,000	43,000	43,000
Net finance costs	531,512	565,115	714,505	741,209	787,269	810,330	863,802
Income tax expense	128,874	205,002	536,971	334,688	190,723	218,651	228,668
Tax on net movement in regulatory	64,130	(131,289)	(352,966)	(121,942)	31,654	22,590	7,147
Employee future benefits	15,993	8,604	8,604	8,604	8,604	8,604	8,604
Contributions received from customers revenue recognized	(66,847)	(72,496)	(85,531)	(95,782)	(102,241)	(109,681)	(116,723)
	$ 2,551,987	$ 2,628,724	$ 3,074,822	$ 3,100,097	$ 3,173,822	$ 3,457,629	$ 3,513,649
Changes in non-cash operating working capital:							
Accounts receivable	127,338	154,667	349,253	(39,135)	(39,526)	(39,921)	(40,320)
Unbilled revenue	(437,342)	(32,416)	(32,740)	(33,067)	(33,398)	(33,732)	(34,069)
Inventory	(92,602)	(2,253)	(2,264)	(2,275)	(2,287)	(2,298)	(2,310)
Prepaid expenses	(32,740)	(1,674)	(1,691)	(1,708)	(1,725)	(1,742)	(1,759)
Other current assets	0	(85)	(94)	(103)	(113)	(125)	(137)
Accounts payable and accrued liabilities	1,418,039	(694,666)	54,325	54,867	56,633	57,259	57,894
Other payables	12,509	(4,474)	1,799	1,817	1,835	1,853	1,872
Customer deposits	(14,933)	(97,001)	(17,176)	(17,353)	(17,531)	(17,712)	(17,894)
	$ 980,269	$ (677,900)	$ 351,413	$ (36,957)	$ (36,112)	$ (36,417)	$ (36,723)
Interest paid	(553,390)	(677,498)	(746,210)	(773,390)	(819,932)	(843,483)	(897,452)
Interest received	21,878	112,384	31,705	32,181	32,663	33,153	33,651
Income tax paid	(206,451)	(231,496)	(183,854)	(212,593)	(222,222)	(241,085)	(235,658)
Regulatory balances	(428,015)	530,878	1,440,605	631,542	(159,435)	(123,987)	(37,289)
Net cash from operating activities	$ 2,366,278	$ 1,685,092	$ 3,968,481	$ 2,740,879	$ 1,968,784	$ 2,245,809	$ 2,340,177
Financing activities							
Repayment of long-term debt	(674,214)	(545,486)	(531,853)	(547,647)	(596,804)	(639,971)	(680,715)
Proceeds from long-term debt	3,000,000		1,500,000		3,000,000		2,500,000
Disposal of contributions in aid of construction							
Dividends paid	(485,663)	(373,790)	(433,559)	(490,857)	(444,539)	(449,019)	(541,421)
	$ 1,840,123	$ (919,276)	$ 534,588	$ (1,038,504)	$ 1,958,657	$ (1,088,991)	$ 1,277,864
Investing activities							
Purchase of property, plant and equipment	(2,954,194)	(2,488,997)	(3,479,820)	(2,902,787)	(3,093,572)	(3,205,231)	(3,423,335)
Proceeds on disposal of property, plant and equipment	3,469	0	0	0	0	0	0
Proceeds on disposal of intangible assets		0	0	0	0	0	0
Purchase of intangible assets	(25,735)	(15,525)	(197,380)	(107,000)	(32,000)	(32,000)	(32,000)
Contributions received from customers	62,766	451,067	718,936	203,666	377,697	291,859	372,702
Net cash used by investing activities	$ (2,913,694)	$ (2,053,455)	$ (2,958,264)	$ (2,806,121)	$ (2,747,875)	$ (2,945,372)	$ (3,082,633)
Change in cash	1,292,706	(1,287,639)	1,544,805	(1,103,746)	1,179,565	(1,788,553)	535,409
Cash, beginning of year	302,533	1,595,236	685,286	2,225,091	1,121,346	2,300,911	512,358
Cash, end of year	$ 1,595,236	$ 685,286	$ 2,225,091	$ 1,121,346	$ 2,300,911	$ 512,358	$ 1,047,767

13. CONCLUSION

The 2024 Budget presents a steady and resilient financial outlook within a challenging inflationary economic environment. The 2024 Budget has been prepared with conservative assumptions with regards to growth, along with trying to account for unknown inflationary fluctuations.

The 2024-2028 Business Plan provides a consistent and stable financial outlook while preparing for the challenges ahead. Orangeville Hydro continually reviews its business and operational goals against its workforce needs, its financial strength, and the impact on its customers. All projected revenues and expenses have been closely examined to ensure accuracy, with conservative assumptions with regards to growth as well as alignment with the definitions within the Ontario Energy Board Accounting Procedures Handbook. Orangeville Hydro continues to be focused on maintaining the adequacy, reliability, and quality of service to its distribution customers through effective capital and operational spending.

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Appendix B – OHL's Asset Condition Assessment

METSCO

MAKING IT POSSIBLE

ASSET CONDITION ASSESSMENT FINAL DRAFT REPORT 2021

Prepared by

Project Number: P-18-178

Wednesday, August 25, 2021

METSCO Energy Solutions

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Revision	Date	Author	Description	Signature
1.0	February 7, 2019	D. Lizak	Preliminary ACA framework with data collection recommendations.	
2.0	May 7, 2021	D. Lizak	Initial release for review.	
3.0	25 August 2021	D. Lizak	Final release.	

Disclaimer

This report was prepared by METSCO Energy Solutions Inc. ("METSCO") for the sole benefit of Orangeville Hydro Limited ("OHL" or the Client), in accordance with the terms of the METSCO proposal and the Client Agreement.

Some of the information and statements contained in the Asset Condition Assessment ("ACA") are comprised of, or are based on, assumptions, estimates, forecasts and predictions and projections made by METSCO and OHL. In addition, some of the information and statements in the ACA are based on actions that OHL currently intends it will take in the future. As circumstances change, assumptions and estimates may prove to be obsolete, events may not occur as forecasted, predicted, or projected, and OHL may at a later date decide to take different actions to those it currently intends to take.

Except for any statutory liability which cannot be excluded, METSCO and OHL will not be liable, whether in contract, tort (including negligence), equity or otherwise, to compensate or indemnify any person for any loss, injury or damage arising directly or indirectly from any person using or relying on any content of the ACA.

Executive Summary

Context of the Study

Orangeville Hydro Limited ("OHL") is an electricity distributor operating a system made up of 3 substations and 222 km of medium-voltage distribution lines delivering electricity to approximately 12,810 residential and commercial customers in the communities of Orangeville and Grand Valley. OHL engaged METSCO Energy Solutions to prepare a comprehensive Asset Condition Assessment ("ACA") study for the assets comprising OHL's distribution system. The ACA is required as one of the key inputs for the preparation of OHL's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB").

Scope of the Study

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

- Wood Poles
- Concrete Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Pole Mount Transformers
- Distribution Pad Mount Transformers
- Load & Air Break Switches
- Inline Switches
- Switchgears
- Substation Power Transformers

All asset condition data used in the study are maintained by OHL as part of its regular asset management practices and collected in compliance with the Distribution System Code requirements. METSCO received OHL's data between January 2021 to August 2021.

Methodology and Findings

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

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

Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated Health Indices for every asset class in the scope of its assessment using a selected HI model. The HI for each asset class is made up of available and relevant "condition parameters" – individual characteristics of the state of an asset's components – each with its own sub-scale of assessment, and a weighting contribution that represents the percentage in the overall HI made up by the parameter. METSCO's findings for each asset class were developed using this methodology, as described in more detail in Section 3 and Section 4. The consolidated results of the Asset Condition Assessment are summarized in Figure 0-1.

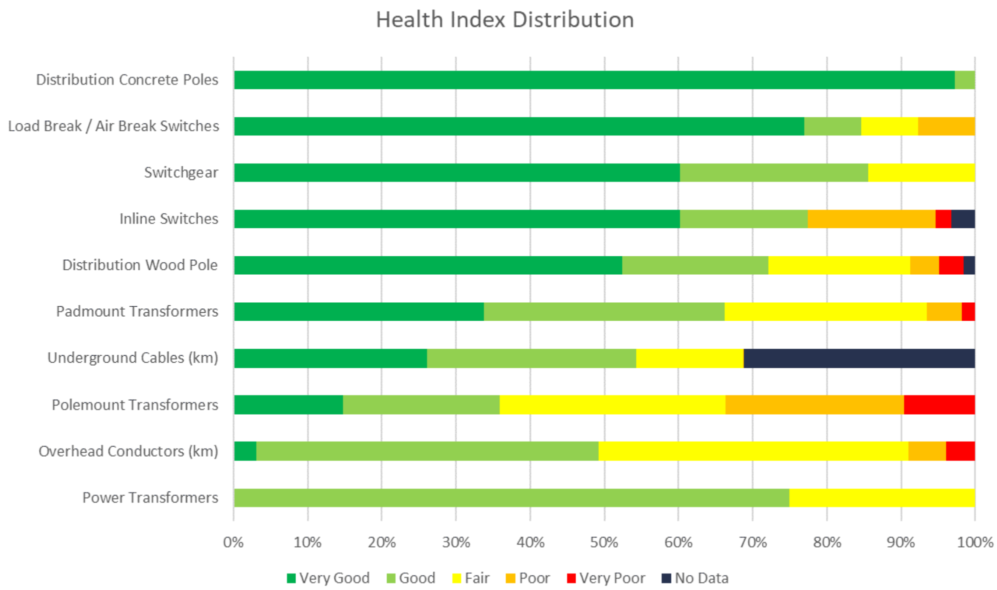

Figure 0-1: Health Index Results

As the figure above indicates, the majority of OHL's distribution system is in Fair condition or better condition, with several specific asset classes containing units found to be in Poor and Very Poor condition – most notably Wood Poles and Pole Mount Transformers. Table 0-2 presents the numerical HI summary for each asset class. The distribution of Health Indices is based on the total population count of a given asset class. For each asset class, the following details are listed: total population, average HI, average Data Availability Index ("DAI"), and the HI distribution. A DAI is a percentage of condition parameter data available for an asset or asset class, as measured against the condition parameters considered in the HI Formulation. A DAI of 100% for an asset indicates that data was available for all assets and all condition parameters in an asset class. DAI is also calculated for individual condition parameters used in the HI Formulation.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	Health Index Distribution (%)						Average Health Index	Average DAI
		Very Good	Good	Fair	Poor	Very Poor	No Data		
Distribution Wood Pole	1691	52.40%	19.75%	19.04%	3.96%	3.31%	1.54%	83.70%	93.10%
Distribution Concrete Poles	36	97.22%	2.78%	0.00%	0.00%	0.00%	0.00%	89.06%	100.00%
Overhead Conductors (m)	73583.3	3.10%	46.10%	41.77%	5.09%	3.94%	0.00%	66.20%	100.00%
Underground Cables (m)	148163.97	26.06%	28.18%	14.50%	0.11%	0.00%	31.14%	79.40%	95.00%
Padmount Transformers	989	33.77%	32.46%	27.30%	4.65%	1.82%	0.00%	75.95%	97.86%
Polemount Transformers	345	14.78%	21.16%	30.43%	24.06%	9.57%	0.00%	60.81%	97.02%
Load Break Switches	13	76.92%	7.69%	7.69%	7.69%	0.00%	0.00%	82.42%	100.00%
Inline Switches	93	60.22%	17.20%	0.00%	17.20%	2.15%	3.23%	80.40%	53.30%
Switchgear	83	60.24%	25.30%	14.46%	0.00%	0.00%	0.00%	87.65%	99.60%
Power Transformers	4	0.00%	75.00%	25.00%	0.00%	0.00%	0.00%	76.00%	100.00%

OHL's Current Health Index Maturity and Continuous Improvement

Overall, OHL's asset data collection practices are sufficiently robust to enable calculation of recommended Asset Condition Assessment that is consistent with industry best practices.

While the existing framework provides OHL with a significant volume of data, certain procedural and technological enhancements could further the granularity of its asset condition data and facilitate calculation of a greater proportion of numerical degradation scores. To this end, Section 5 of this study includes a set of METSCO's recommendations for incremental data collection enhancements that OHL can consider going forward based on its assessment of their relative cost-benefit tradeoffs.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of ageing infrastructure, changing climate, evolving customer needs, and many other priorities. As such, adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

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1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an engineering and management consulting firm specializing in work with electric and natural gas utilities. As a part of our Asset Management ("AM") consulting practice we have conducted numerous Asset Condition Assessments ("ACAs") commissioned by utilities, regulators, private sector power consumers and financial institutions. Aside from the practical experience in conducting the ACA studies, METSCO's engineers made significant contributions to the development and refinement of Health Index ("HI") methodologies across multiple asset classes through field work and a variety of R&D activities. METSCO's collective record of experience in the area of asset management for electricity transmission and distribution utilities is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions. A selection of METSCO's past clients and projects is attached as Appendix A to this report.

Orangeville Hydro Limited ("OHL") is an electricity distributor operating within the South-Central Ontario region. OHL engaged METSCO to prepare a comprehensive ACA study for the assets comprising OHL's distribution system. The ACA is required as one of the key inputs for the preparation of OHL's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to generate and report on the Health Indices grounded in the latest condition data of in-service assets – to enable future prioritization of asset renewal investments using objective decision inputs. Supplementary objectives included preparing the ACA results to be used for OHL's upcoming rate filing as well as to continuously improve OHL's asset and data management framework.

A dedicated ACA methodology is applied to each major asset class covered in this report. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections, and recording of asset data – to identify the assets most at risk at reaching the end-of-life criteria over the relevant planning horizon. Where asset condition information is not recorded, other objective data such as asset age, make, or wear and tear sustained in operation can be used as proxies of condition, based on industry-accepted conversion scales. Each asset health criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life, using METSCO's algorithms refined over time and tested in multiple regulatory proceedings.

The report covers the following major asset classes:

- Wood Poles
- Concrete Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Pole Mount Transformers
- Distribution Pad Mount Transformers
- Load & Air Break Switches
- Inline Switches
- Switchgears
- Substation Power Transformers

All the asset condition data is maintained by OHL as part of its regular asset management and collected in compliance with the Distribution System Code requirements. METSCO received OHL's data for the current condition assessment with date records between January 2021 to March 2021.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the PAS-55 and ISO 55000/55001/55002 standards, discusses how the ACA fits into the overall asset management framework; and provides an overview of METSCO's ACA methodology;
- Section 3 summarizes the asset HI calculation methodology;
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes;
- Section 5 summarizes METSCO's recommendations for OHL on data collection improvements for continuous improvement efforts for the ACA; and
- Section 6 summarizes METSCO's concluding remarks.

2 Context of the ACA within AM Planning

An ACA is a critical step in developing an objectively informed asset replacement strategy. An ACA study involves collection, consolidation, and utilization of the results within an organizational AM framework to objectively quantify and manage the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA framework is designed to provide utilities with insights into the current state of an organization's asset base, the risks associated with anticipated degradation, and approaches to managing this degradation within the current AM framework while ensuring that the organization extracts the expected value out of the asset base.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

One of the most widely recognized industry standards for AM Planning is the ISO 5500X group of standards (which captures 55000, 55001 and 55002). According to these standards, each business entity finds itself at one of the three main stages along the Asset Management journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous Improvement stage - those looking to assess and progressively enhance an asset management system already in place for avenues of improvement.

Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

An asset is any item or entity that has value to the organization. This value can be actual or potential, expressed in either a monetary or another manner valuable to an organization (including intangible outcomes like public safety). The primary job of an asset manager is to extract the maximum amount of value out of the group of assets in their care. Asset managers accomplish these objectives by way of tools and processes that are collectively known as the Asset Management System or Framework. Figure 2-1 displays the key

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

elements of such a framework expressed as a hierarchy of organizational systems. An asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. Around the asset portfolio, the AM System represents a set of interacting elements that establish the policy, objectives, and processes that help the organization achieve the objectives associated with preserving their assets in a working order to extract the intended value from them. The AM system is, in turn, embedded within the system AM practices – coordinated practical activities guided by the principles and processes defined in the AM System to realize the maximum value from the asset portfolio. Finally, the Organizational Management layer provides for an informed and consistent execution of the policies and processes underlying an AM System. [1]

The ACA framework is among the AM tools or procedures that enable Asset Managers to turn the known condition information into actionable insights based on the level of deterioration identified through inspections, testing and their subsequent analysis.

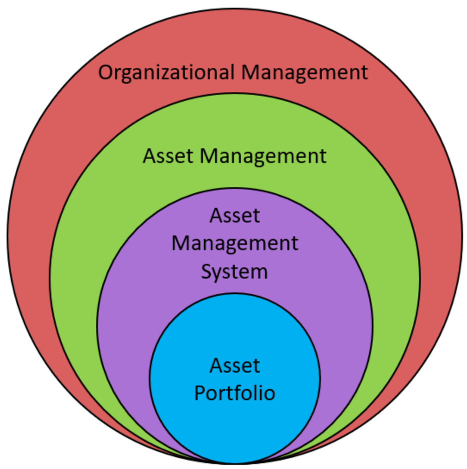


Figure 2-1: Relationship between key Asset Management terms[1]

2.1.1 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to: the collection and storage of technical specifications, historical asset performance, projected asset behaviour and degradation, the configuration of an asset or asset-group within the system, the operational relationship of one asset to another, etc. In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process is to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to AM being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or the acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 5500X states explicitly that all asset portfolio improvements should be assessed via a risk-based approach before being implemented.[1] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

2.2 Continuous Improvement in the AM Process

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that also includes a clear and compelling expression of the organization's values in relation to how it intends to manage its assets. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be shared between all relevant agents (executive leadership, technical experts, operations and maintenance staff, or finance decision-makers) and updated regularly, to capture the most current AM practices being implemented (including the trade-offs made in the process). Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigour.[1]

Asset Management should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio (including the insights regarding effectiveness and value for money of the AM processes themselves). Continually

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework. [1]

3 Asset Health Index Calculation Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study can be is a four-phase procedure:

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

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

3. *HI and Data Availability Index ("DAI") calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from OHL to improve the accuracy of the asset health calculation if applicable.

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

3.2 Data Sources

To assess the demographics and establish the unit population of OHL's system assets, METSCO was provided with OHL's asset demographic data from its current Geographic Information System ("GIS"). The data came from OHL's corporate asset registries containing information on asset vintage, model, and year of commissioning. The database served as the primary asset library that contained asset nameplate information such as age and unique identifiers.

To assess the condition of OHL's system, METSCO was provided with available asset inspection and maintenance data for the asset classes in scope. Various sources hold records of OHL's inspection and maintenance activities. Most of the data came from primary sources such as equipment inspection forms completed by OHL staff or contractors, or the results of specific tests such as the Dissolved Gas Analysis ("DGA") for station power transformer oil.

Additionally, METSCO was provided with historical operating data for assets that require operating information for the HI calculation. An example of operating data used is the historical loading information for transformers.

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. *Additive models* – asset degradation factors and scores are used to independently calculate a score for each asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. *Gateway models* – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. *Subtractive models* – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. *Multiplicative models* – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents that are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of OHL's peer utilities.

It is also important to note that in cases where a utility does not possess at least three different asset health parameters for a given asset class, we refer to the resulting health calculation as a One- or Two-Parameter Health Assessment rather than a HI. This distinction in nomenclature is entirely a function of reporting clarity rather than a commentary on the sufficiency of information to make observations about the health of a given asset class. In METSCO's view, an *index* is a product of multiple inputs, and as such, it is not an appropriate term to describe a result of an assessment based on single data input or even a pair of inputs.

3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To calculate an HI (or a one-/two-parameter health assessment) for a given asset class, formulations are developed based on available condition parameters that can be expected to contribute to the degradation and eventual failure of that type of asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset relative to others. Figure 3-1 exemplifies an HI formulation table.

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

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

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

Figure 3-1: HI Formulation Components

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-conditions parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

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

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

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset conditions are the notion that age implies a linear degradation path for an asset that does not always match the experience in the field.

While some assets lose their structural integrity faster than would be expected over time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period than age-based degradation would imply. In recognition of the argument as to the limitations of age-based condition scoring, METSCO attempts to limit the instances where it relies on only age as a parameter explicitly used in the HI formulation.

In some cases, however, the limited number of condition parameters available for the calculation of asset health makes age the only viable proxy for condition degradation. In other cases, such as when assessing the condition of complex equipment containing several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.4.3 Implications of OHL's Current Approach to Asset Data Collection

To be worthwhile of the incremental cost and effort, the collection and analysis of any new asset health data must give the utility confidence that the benefits of the resulting insights can lead to commensurate value gains. In cases where available spending levels limit the amount of inspection/testing work a utility can perform in a given year, management must prioritize among asset classes where more information is advisable, and those where lack of medium-longer-term planning precision can be a tolerable risk. In our engagements with OHL, we have confirmed that the utility's management applies this reasoning to the scoping of its inspection activities and setting of the associated budgets.

This approach is evident in practice when considering the relative number of testing and inspection data parameters available for OHL's major substation asset 'Power Transformers', where the utility collects substantially more condition data than it does for its linear infrastructure. METSCO understands that this trade-off is in part informed by OHL's maintenance strategy to yield long-term shareholder and ratepayer value. It means that it is critical for OHL to identify any material changes in the health of its station assets as early as possible, to ensure that station preventative maintenance work can take place in time to avoid in-service failure and costly reactive replacement of the asset class slated for wholesale retirement.

Importantly, the relative lack of linear infrastructure health data records does not correspond to a lack of diligence in asset management. In the case of OHL (and multiple other Ontario distributors), it continues to rely on an Exception-Based approach to equipment deficiency reporting for overhead and underground line assets. This approach entails making a specific record of an asset's health parameters only when the inspection reveals deficiencies indicative of imminent failure and/or other potential hazards requiring near-term rectification (e.g. safety issues or significant vegetation encroachments). Relying on data drawn from the Exception Records, OHL creates work orders to rectify the identified issues in the near term (prioritizing them based on relative urgency and other relevant operating factors).

Accordingly, while the Exception-Based asset health reporting approach does not generate records that could be used to generate Health Indices for an entire population of assets, it relies on modern multi-point inspection methodologies and relies on various testing tools. As such, this approach ensures that all assets are inspected in accordance with the DSC requirements, all imminent issues are addressed promptly while managing the utility's overall inspection and testing budget. Inherent in this approach is an implicit trade-off between the precision of asset intervention planning over a medium/longer term and the rate impact of inspection work. Considering that OHL's asset management approach for line infrastructure has largely relied on a Run to Failure approach, METSCO sees the current approach to asset inspection and asset data record-keeping as a reasonable exercise of management's discretion.

3.4.4 Final Health Index Formulation

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

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

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through the identification of condition parameters acknowledged being critical indicators of overall asset health.

3.4.5 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time.

Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for asset intervention before failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available by the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

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

Where *i* corresponds to the condition parameter number and *α* is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 65%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small populations and higher complexity of equipment (and thus potential asset health issues).

4 Asset Condition Assessment Results

This section presents the current HI formulation for each asset class, the calculated scores for Health Indices, as well as the data available to perform the study.

4.1 Distribution Wood Poles

Table 4-1: Distribution Wood Poles Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Wood Rot/Decay	6	A,B,C,D,E	4,3,2,1,0	24
2	Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
3	Age	3	A,B,C,D,E	4,3,2,1,0	12
				Total Score	**84**

Distribution poles are an integral part of any distribution system. They support the structure for overhead distribution lines often found with installed assets such as overhead transformers, switches, reclosers, and streetlights. The HI for wood poles is estimated by considering a combination of end-of-life criteria summarized in Table 4-1. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Appendix B – Condition Parameters Grading Tables provides grading tables for each condition parameter.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage and effects of weather which can impact the mechanical strength of the pole. Any loss in the strength of the pole can present additional safety and environmental risks to the public and OHL.

OHL owns 1691 distribution wood poles within its service territory. The HI distribution for wood poles is presented in Figure 4-1.

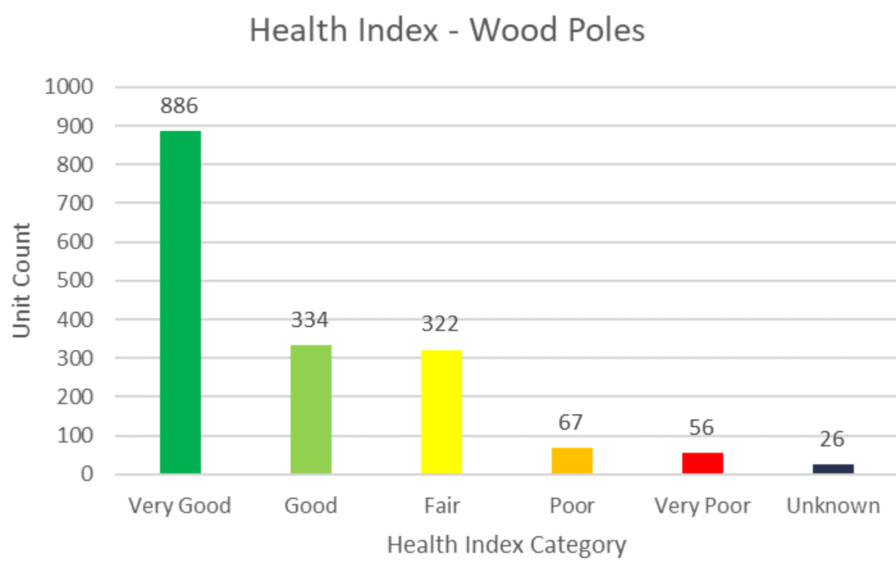


Figure 4-1:Distribution Wood Poles Health Index Demographic

OHL's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-1. Table 4-2 presents the DAI of individual condition parameters used for the wood pole HI framework. In 2020, OHL conducted additional Resistograph tests for both Orangeville and Grand Valley regions. This resulted in improved data availability for condition parameters Wood Rot/Decay and Defects/Overall Condition (both 45% in 2018). Testing criteria for each condition parameter can be found in Appendix B.

In 2016 and 2020, OHL utilized Resistograph tests on selected wood poles. In 2017, OHL utilized the Polux test on selected wood poles and conducted retests of these poles in 2019. Both sets of wood pole inspections were completed by a third-party contractor who conducts a visual inspection checking for the following related fields to the wood pole:

- Surface decay (2017/2019 inspection) / Decay (2016/2020 inspection)
- Mechanical Damage (2017/2019 inspection) / Cavity (2016/2020 inspection)

The pole inspector indicates for each field a numerical value. However, both test results use a different set of numerical values – the 2017/2019 results measure values in inches ranging from 0 to more than 1.5 inches, whereas the 2016/2020 results calculate a percentage ranging from 0 to 100%. Visual inspection can detect the following types of wood pole damage:

- Fibre damage that may occur when the wind hits a wood pole with force beyond the pole's bearing capacity;
- Animal and/or insect damage and infestation;

- Partial damage may result when objects hit wood poles and reduce effective pole circumference. If the damage affects only part of a pole's cross-section the utility may keep the pole in-service with a reduced factor of safety;
- Burning from conductor faults and insulator flashovers may damage the wood poles reducing the ability of these structures to withstand mechanical stress changes or causing their complete loss through fire incidents;
- Wood cracks that may hold moisture and cause decay or weaken the structures through freeze/thaw forces during winter; and
- Various types of wood rot in possible locations are visually seen by the inspector.

Table 4-2: Distribution Wood Poles condition parameters data availability

Condition Parameter	% of Assets with Data
Wood Rot/Decay	92%
Overall Condition	92%
Age	98%

The average DAI across the distribution wood pole asset class is 93.1%.

4.2 Distribution Concrete Poles

The HI for concrete poles is calculated by considering service age and visual inspection criteria. Table 4-3 summarizes the methodology to generate the HI for concrete poles.

Table 4-3: Distribution Concrete Poles Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
3	Out of Plumb	3	A,B,C,D,E	4,3,2,1,0	12
				Total Score	**48**

OHL owns 36 distribution concrete poles within its service territory. The HI distribution for distribution concrete poles is presented in Figure 4-2.

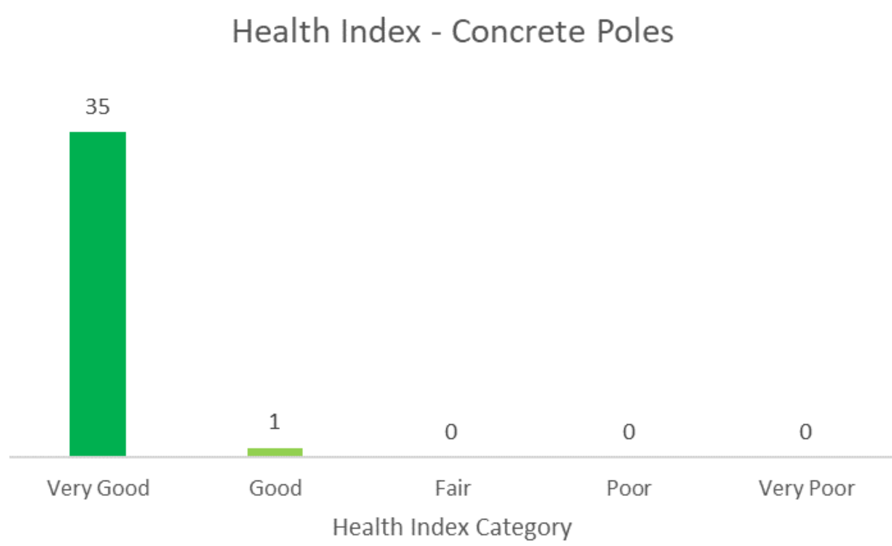


Figure 4-2:Distribution Concrete Poles Health Index Demographic

OHL's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-3. The population does not exhibit any Poor condition poles. The average DAI across the concrete pole asset class is 100%. Table 4-4 presents the DAI of individual condition parameters used for the concrete pole HI framework.

Table 4-4: Distribution Concrete Poles condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Overall Condition	100%
Out of Plumb	100%

4.3 Overhead Primary Conductor

Table 4-5: Overhead Primary Conductor Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	5	A,B,C,D,E	4,3,2,1,0	20
2	Small Conductor Risk	5	A,B,C,D,E	4,3,2,1,0	20
				Total Score	**40**

Overhead primary conductors transmit electricity from substations to customer premises and are supported by service poles. Due to having less than three condition parameters available, this assessment is labelled a "two-parameter assessment". The two-parameter assessment formulation for overhead primary conductors is summarized in Table 4-5. Appendix B provides grading tables for each condition parameter. There are various voltage ratings across the conductors that make up the Overhead Distribution system. The below

Figure 4-3 below outlines the voltage breakdown of the asset class. As seen in Figure 4-3, 28% of overhead conductors have a voltage rating of 12.4kV or lower.

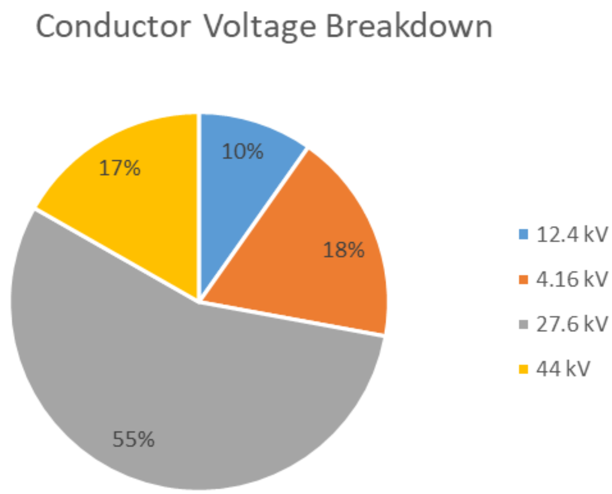


Figure 4-3: Overhead Conductor Voltage Breakdown

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

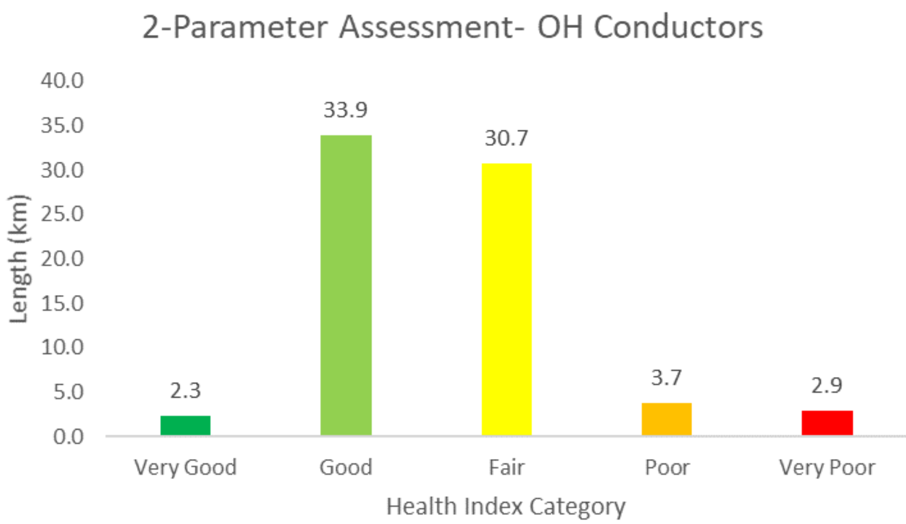


Figure 4-4 Overhead Primary Conductor Assessment Demographic

OHL owns approximately 74 km of the overhead primary conductor within its service territory. The installation date was unknown for approximately 97% of conductor segments. To address this large data gap, an age extrapolation method was used based on the known ages and locations of pole-mounted transformers. The age distribution of pole-mounted transformers on a given circuit was extrapolated to the overhead conductor population on that circuit. For example, on circuit M25, 4% of pole-mounted transformers were found to be within 0-10 years of age (Very Good age band), 71% found to be within 11-30 years (Good age band), 18% found to be within 31-50 years (Fair age band) and 7% within 51-70 years (Poor age band). These percentages were applied to the total length of circuit M25 such that 4% of the total length is considered Very Good, 71% Good, etc. This process was repeated for all common circuits between pole-mounted transformers and overhead conductors. With this extrapolation method, 35% of the population still had unknown ages due to no common circuits between the asset class and pole-mounted transformer. For this portion of the population, OHL SMEs provided assumed ages to address the data gap. Figure 4-4 illustrates the overall assessment for overhead primary conductors. The average assessment score for overhead primary conductors is 66.3%.

Table 4-6: Overhead Primary Conductor condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	3%*
Small Conductor Risk	100%

**Does not include extrapolated age*

The average DAI across the overhead primary conductor asset class is 51.5%. Table 4-6 presents the DAI of individual condition parameters used for the overhead primary conductor's two-parameter assessment framework.

4.4 Underground Primary Cable

Table 4-7: Underground Primary Cable Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	5	A,B,C,D,E	4,3,2,1,0	20
				Total Score	**20**

Like overhead conductors, underground cables also transmit electricity within the electrical distribution system, however, they are located below ground. Compared to overhead lines, they are much more reliable since they are not exposed to severe weather conditions, tree contacts or foreign interference. However, the distribution underground cables are more expensive and are one of the more challenging assets in electricity systems from a condition assessment and asset management viewpoint. Several test techniques, such as partial discharge (PD) and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. The historical common approach to managing cable systems has been monitoring of cable failure rates and the impacts of in-service failures on reliability and operating costs and when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of cable replacement, the cables are replaced. After discussions with OHL SMEs, it was determined there are no recorded circuit failures related specifically to underground cables thus the one-parameter assessment is calculated considering only age.

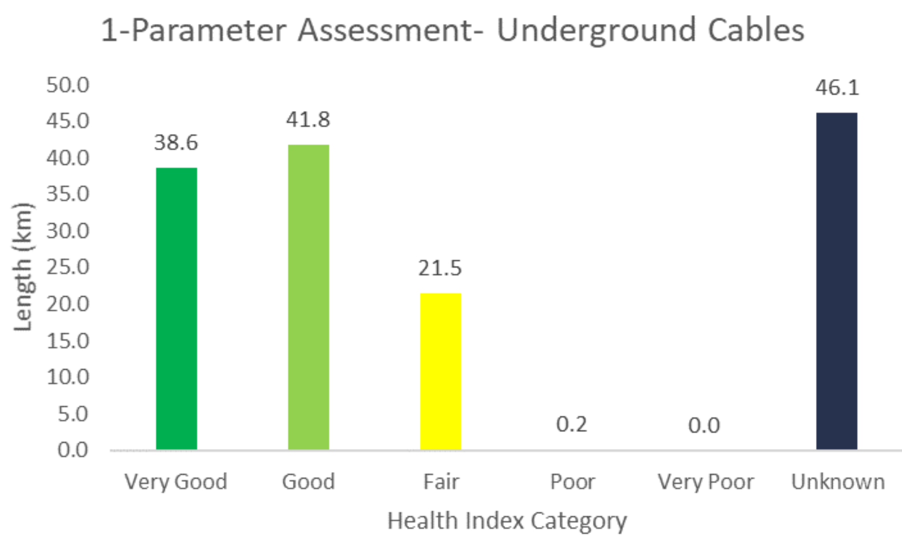


Figure 4-5: Underground Primary Cable Assessment Demographic

OHL owns approximately 148 km of underground primary cable within its service territory. There are various voltage ratings across the cables that make up the Underground Distribution system. Figure 4-6 below outlines the voltage breakdown of the asset class. The installation date was unknown for 98% of cable segments. A similar age extrapolation method as described for overhead conductors was used for underground cables. In this case, pad-mounted transformer ages and locations were utilized. The average assessment score for underground primary cable is 79.4%.

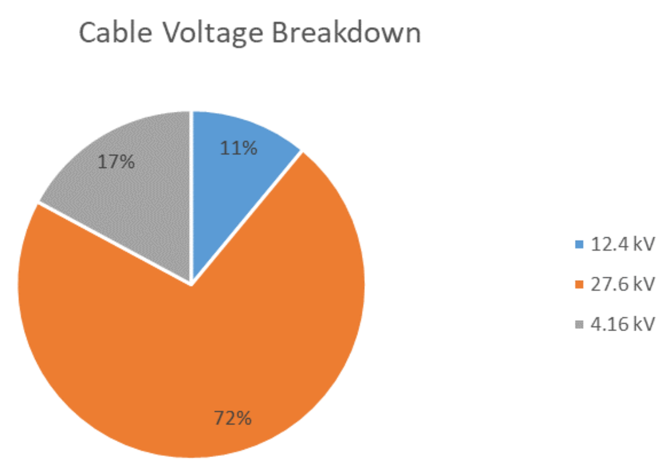


Figure 4-6: Underground Cable Voltage Breakdown

Table 4-8: Underground Primary Cables condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	2%*

**Does not consider extrapolated age*

The average DAI across the underground primary cable asset class is 2% with service age being the sole parameter and not considering extrapolated age. Table 4-8 presents the DAI of individual condition parameters used for the underground primary cable one-parameter assessment framework.

4.5 Distribution Pole Mount Transformer

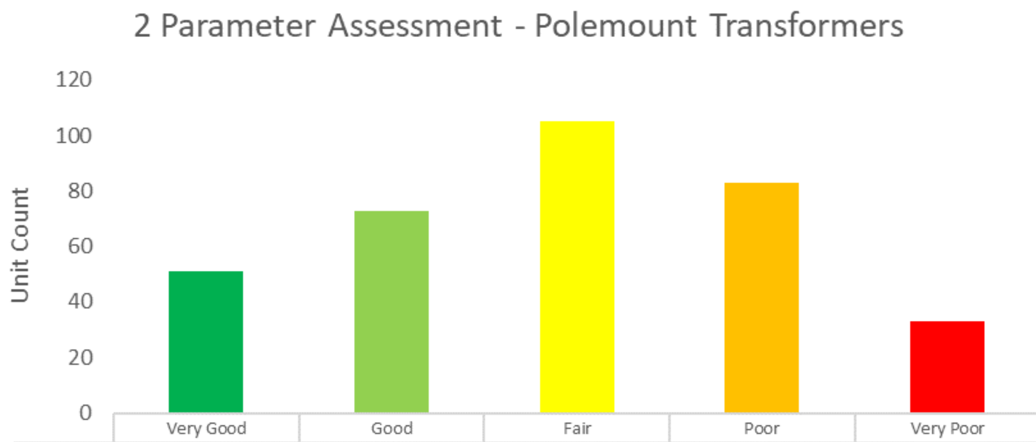
Table 4-9: Pole Mount Transformer Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Peak Loading	4	A,B,C,D,E	4,3,2,1,0	16
				Total Score	**28**

Overhead (pole mount) transformers are installed on service poles above ground with the primary function to step down power from the medium voltage distribution system to the final voltage rating for customer use. The pole mount transformers are assessed by considering a combination of end-of-life criteria summarized in Table 4-9. Due to having less than three condition parameters available, this assessment is labelled a "two-parameter assessment". Appendix B provides grading tables for each condition parameter.

In addition to service age, the peak loading experienced by the transformer is considered in the assessment. Load unbalances or peak loading reduces the useful life of a distribution transformer. In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil.

OHL owns 345 pole mount transformers within its service territory. OHL's transformer nameplate information and operating loading data were used to calculate the two-parameter assessment based on the criteria provided in Table 4-9. The overall two-parameter assessment distribution is presented in Figure 4-7 for the overhead transformer.



	Very Good	Good	Fair	Poor	Very Poor
44 kV	0	0	0	0	0
27.6/16 kV	17	22	27	6	2
16 kV	25	46	54	43	11
12.4/7.2 kV	3	1	2	0	1
7.2 kV	3	3	11	22	7
4.16/2.4 kV	1	0	3	0	0
2.4 kV	2	1	8	12	12

Figure 4-7: Pole Mount Transformers Health Index Demographic

The average assessment of the overhead distribution transformers is 60.8%. It can be noted that most of this asset class is in Fair condition or worse. Typically, pole mount transformers are replaced when a pole requires replacement or has failed. This results in this asset class having a large portion of its population being at a higher age (35% of the population over 30 years). This run to fail/adjacent replacement program combined with age being a large component of the overall assessment calculation speaks to the number of Fair to Very Poor units.

Table 4-10: Pole Mount Transformers condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Peak Loading	95%

The average DAI for the condition parameters for pole-mount transformers is 97%. Table 4-10 presents the DAI of individual condition parameters used for the overhead distribution transformer assessment framework.

4.6 Distribution Pad Mount Transformer

Distribution pad mount transformers are utilized for similar functionalities as pole mount transformers. They step down power from the medium voltage distribution system to the final utilization voltage for the customer, however, they are located on ground level.

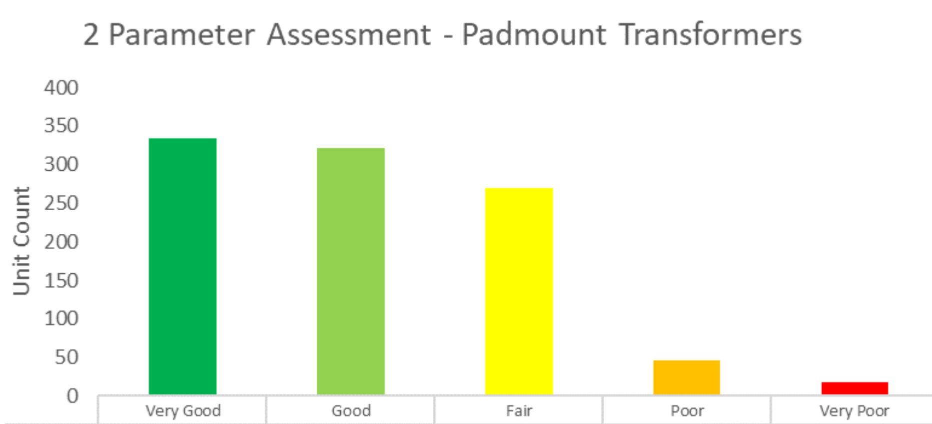
Table 4-11: Pad Mount Transformer Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Transformer Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Peak Loading	4	A,B,C,D,E	4,3,2,1,0	16
				Total Score	**28**

The two-parameter assessment for distribution pad mount transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-11. Appendix B provides grading tables for each condition parameter.

The peak loading experienced by the transformer is a good condition parameter to use. Load unbalances or peak loading reduces the useful life of a distribution transformer. In general, the useful life of a transformer is determined by its insulation condition which is largely affected by transformer loading, temperature, and presence of oxygen and moisture in the oil.

OHL owns 989 pad mount transformers within its service territory. OHL's transformer maintenance records, nameplate information, and operating loading data were used to calculate the two-parameter assessment based on the criteria provided in Table 4-11. The overall two-parameter assessment distribution is presented in Figure 4-8



	Very Good	Good	Fair	Poor	Very Poor
44 kV	0	0	0	0	1
27.6/16 kV	62	63	10	6	2
16 kV	220	240	143	13	0
12.4/7.2 kV	10	0	3	0	0
7.2 kV	34	2	24	1	0
4.16/2.4 kV	2	2	9	1	2
2.4 kV	6	14	81	25	13

Figure 4-8: Pad Mount Transformers Assessment Demographic

Approximately 7% of OHL's pad mount transformers have a peak loading percentage of 100% or greater which can pose operating restrictions and impact the condition of the assets. All assets in the Poor or Very Poor categories are transformers with a peak loading percentage of 100% or greater. The majority of pad mount transformers are in Very Good or Good condition with an average score of 76% across the population.

Table 4-11: Pad mount Transformer condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Peak Loading	96%

The class-average DAI for pad mount transformers is 98% respectively. Table 4-11 presents the DAI of individual condition parameters used for the distribution pad mount transformers two-parameter assessment framework.

4.7 Load Break Switches

Table 4-12: Load Break Switch Assessment Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	4	A,B,C,D,E	4,3,2,1,0	16
2	Condition of Insulators & Blades	3	A,B,C,D,E	4,3,2,1,0	12
				Total Score	**28**

Load break switches are operated to sectionalize the circuit during a restoration procedure by breaking all three phases of load with a single operation. The two-parameter assessment for switches considers a combination of end-of-life criteria summarized in Table 4-12. Each condition parameter represents a factor critical in determining the asset's condition relative to a potential failure to occur. Appendix B provides grading tables for each condition parameter.

OHL owns 13 load break switches within its service territory. Asset nameplate information was used to evaluate the asset's condition based on the criteria provided in Table 4-12. Figure 4-9 presents the two-parameter assessment distribution for this asset class.

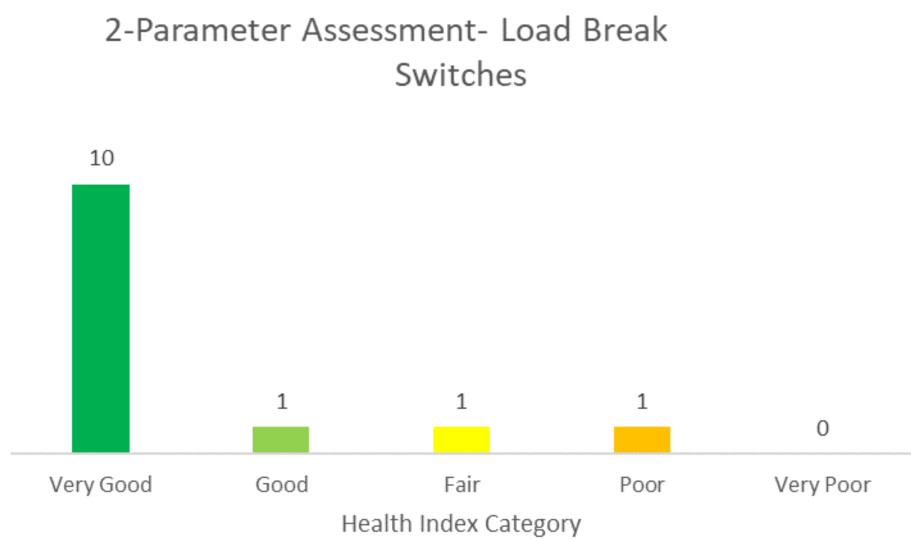


Figure 4-9: Overhead Switches Assessment Demographic

77% of the switches are in Very Good condition. All units had inspection results that indicated no signs of deterioration to the switch insulators and blades.

Table 4-13: Distribution Overhead Switches condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	100%
Condition of Insulators and Blades	100%

The average DAI for load break switch data is 100%. Table 4-13 presents the DAI of individual condition parameters used for the load break switch two-parameter assessment framework.

4.8 Inline Switches

Table 4-14: Inline Switch Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	3	A,B,C,D,E	4,3,2,1,0	12
2	Connection Pitting	3	A,C,E	4,2,0	12
3	Insulator Inspection	3	A,C,E	4,2,0	12
4	Blade Condition	3	A,C,E	4,2,0	12
				Total Score	**60**

Table 4-14 describes the inspection criteria for inline switches. Appendix B provides grading tables for each condition parameter.

OHL owns 93 inline switches within its service territory. The asset's nameplate information was used to calculate the HI based on the criteria provided in Table 4-14. Figure 4-10 presents the HI distribution for this asset class.

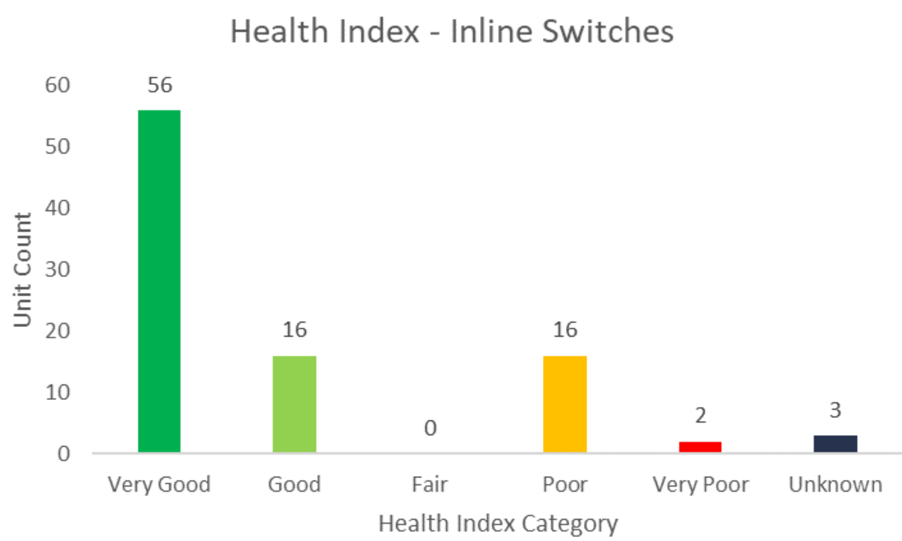


Figure 4-10: Inline Switch Health Index Demographic

51% of inline switches resulted in a Very Good HI score resulting in an average score of 80.4% across the asset class. As indicated in Table 4-15, there are some data gaps across the asset population. OHL has recently begun a detailed inspection for this asset class with detailed data recording, therefore, not all assets have gone through an inspection cycle. 53% of inline switches have inspection results resulting in a portion of the population only relying on age for its HI score. Also evident in Figure 4-10 is the three switches that could not have a HI calculated. These assets are missing both age and inspection data thus could not have a calculation completed. The average DAI for this asset class is 67%. Table 4-15 presents the DAI of individual condition parameters used for the HI framework.

Table 4-15: Inline Switches condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	80%
Connection Pitting	62%
Insulator Inspection	62%
Blade Condition	62%

4.9 Power Transformer

Table 4-16: Power Transformer Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	DGA	10	A,B,C,D,E	4,3,2,1,0	40
2	Load History	10	A,B,C,D,E	4,3,2,1,0	40
3	Oil Quality	8	A,B,C,D,E	4,3,2,1,0	32
4	Service Age	8	A,B,C,D,E	4,3,2,1,0	32
5	Overall Condition	6	A,B,C,D,E	4,3,2,1,0	24
6	Oil Level	1	A,B,C,D,E	4,3,2,1,0	4
				Total Score	**170**

Power transformers in the distribution system are housed within municipal station yards enclosed by fences. They are used to step down the voltage within the distribution system to supply end users. Table 4-16 summarizes the methodology to generate the HI for oil-type power transformers. The HI score for a power transformer is composed of six parameters. Each of these parameters represents an aspect of a power transformer with a direct impact on the operational health of the asset.

By performing the dissolved gas analysis ("DGA"), it is possible to identify the internal faults such as arcing, partial discharge, low-energy sparking, severe overloading, and overheating in the insulating medium. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights.

Although load history is not a test, it holds value as an input for the HI algorithm. The peak loading information dating from 2016-2018 was used for the analysis. The rate of insulation degradation is directly related to the operating temperature which is directly related to transformer loading levels. The peak loading level of the transformers is expressed in a percentage of the nameplate rating.

Oil leaks and the overall condition of components are collected by visual inspection and serve as indicators of the total health of the asset. Additionally, the service age of the power transformers serves as a proxy for the degree of polymerization which provides a reasonably good measure of the remaining life of the asset.

OHL owns four oil-type power transformers within its service territory which includes one spare. Of these transformers, one belongs to a substation that is planned to be decommissioned in 2021. Age was known for all the power transformers in the system.

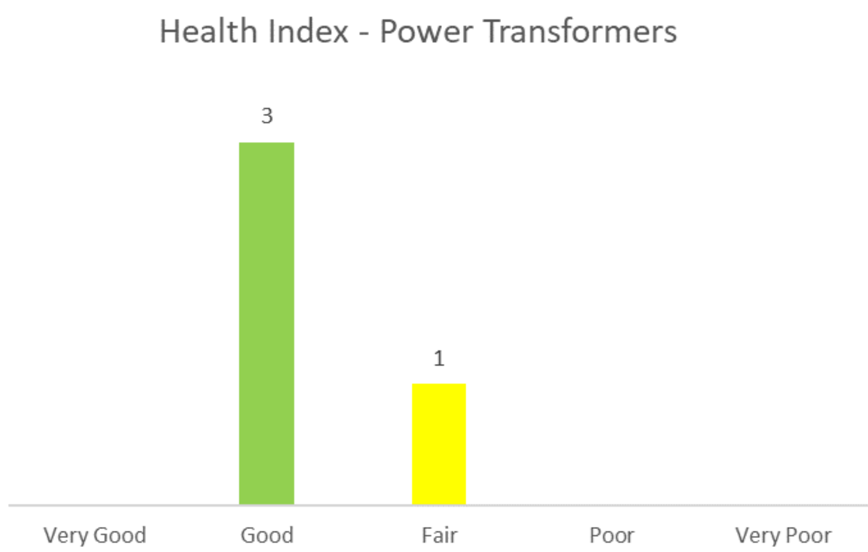


Figure 4-11: Power Transformer Health Index Demographic

OHL's power transformer inspections, test results and loading history were used to calculate the HI based on the criteria provided in Table 4-16. The HI distribution for in-service power transformers leveraged from the substation assessment is presented in Figure 4-11. The average HI for the power transformer population is 78%.

Table 4-17: Power Transformers condition parameters data availability

Condition Parameters	% of Assets with Data
DGA	100%
Load History	100%
Oil Quality	100%
Service Age	100%
Overall Condition	100%
Oil Level	100%

The average DAI for station power transformer data is 100%. Table 4-17 presents the DAI of individual condition parameters used for the power transformer HI framework.

4.10 Switchgear

Table 4-18: Switchgears Health Index Algorithm

#	Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
1	Service Age	4	A,B,C,D,E	4,3,2,1,0	16
2	Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
3	Condition of Pad	4	A,C,E	4,2,0	16
				Total Score	**48**

Station switchgear consists of breakers, fuses, and switches that control and regulate the current flowing through the distribution system. During a fault, the switchgear isolates and clears the faults downstream. It is also used to de-energize equipment during maintenance and testing. OHL's risk management continues to manage the asset's risk of failure through regular visual inspections. An HI was calculated for this asset class using the criteria described in Table 4-18. Appendix B provides grading tables for each condition parameter.

OHL owns 83 switchgears within its service territory. Age was known for the total population of OHL's in-service station switchgears. The results of the HI assessment can be found in Figure 4-12.

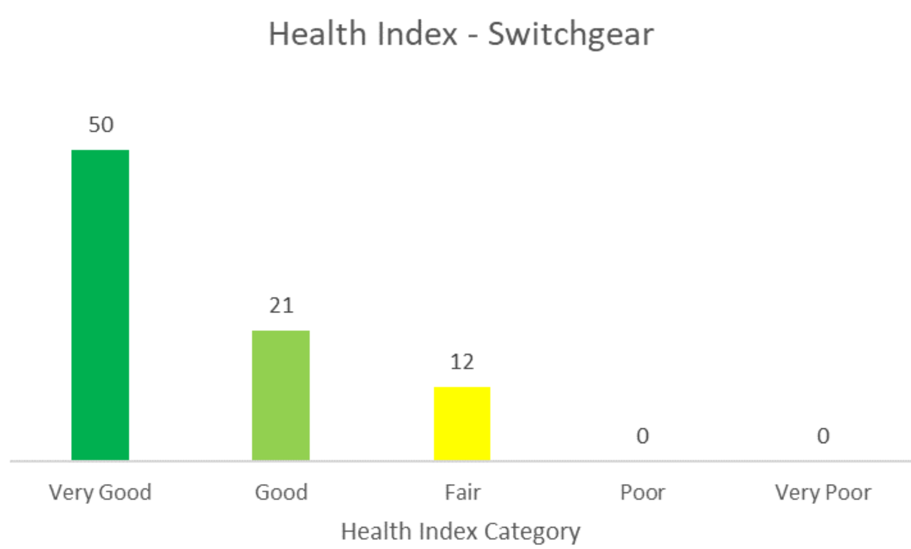


Figure 4-12: Switchgears Health Index Demographic

OHL's maintenance records and nameplate information were used to calculate HI based on the criteria provided in Table 4-18. 86% of the asset class is in Very Good or Good condition, with the remaining 14% of switchgears in Fair condition. No serious indications of poor overall condition or pad condition were indicated in the inspection data. This combined with an average age of 17.7 years results in an average HI score of 87.7%.

Table 4-19: Primary Station Switchgears condition parameters data availability

Condition Parameter	% of Assets with Data
Service Age	99%
Overall Condition	100%
Condition of Pad	100%

The DAI for switchgear data is nearly 100%. Table 4-19 presents the DAI of individual condition parameters used for the switchgear HI framework.

5 Recommendations

A complete ACA framework for OHL represents an integral component of its broader asset management framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the current information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for OHL's investment decision-making to be further enhanced with the current information regarding the state of the assets. However, there are also further opportunities to introduce new data to be collected and improve data availability to continuously improve the ACA framework.

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

- Health Index Enhancements
- Data availability improvements

5.1 Health Index Enhancements

For select asset classes, a recommended HI formulation was used for OHL's ACA framework. The general condition of assets considered in this assessment is as expected but certain asset classes can see room for improvement. Wood Poles, Pole Mount Transformers and Overhead Conductors make up the most significant contribution to the total population of Poor and Very Poor units. This insight suggests a poorer condition of assets that make up the overhead distribution system and could be an area to target in System Renewal efforts. METSCO suggests that OHL focus its efforts on further refining its understanding of the assets in the Poor / Very Poor categories and use any resulting insights to drive its specific asset intervention decisions in the near term and inform the longer-term AM strategy more broadly.

5.2 Data Availability Improvements

Data availability is critical in being able to produce prudent, accurate and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to executing continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA study, each asset class included a breakdown of data available for each condition parameter collected. For condition parameters with low data availability METSCO recommends that OHL continue collecting the information related to these data points.

As part of future improvement opportunities, it is recommended that OHL continue capturing asset data for condition parameters that are currently available for a small proportion of the asset population. Inspection records for wood poles and in-line switches indicate the beginnings of a comprehensive data record, but as indicated in their respective DAI tables, low data availability is present for multiple condition parameters. In addition to this point regards the age data for Overhead Conductors and Underground Cables. While the age extrapolation method discussed in this report is a reasonable approach in assuming conductor age, empirical age data is a preferred input to the HI calculation. Moving forward, METSCO recommends OHL to record conductor installation year within its GIS system. It is expected that with every passing year, the inspection record database will continue to grow and be refined, allowing for HIs to be calculated more reliably.

6 Conclusion

As Figure 6-1 indicates, most assets across OHL asset classes analyzed are in Fair condition or better. This can indicate OHL has taken steps in the past to manage its asset health and performance for the benefit of its customers. As with every system, however, some areas require OHL's attention in the coming years where asset populations contain material portions of equipment in or approaching Poor condition or worse.

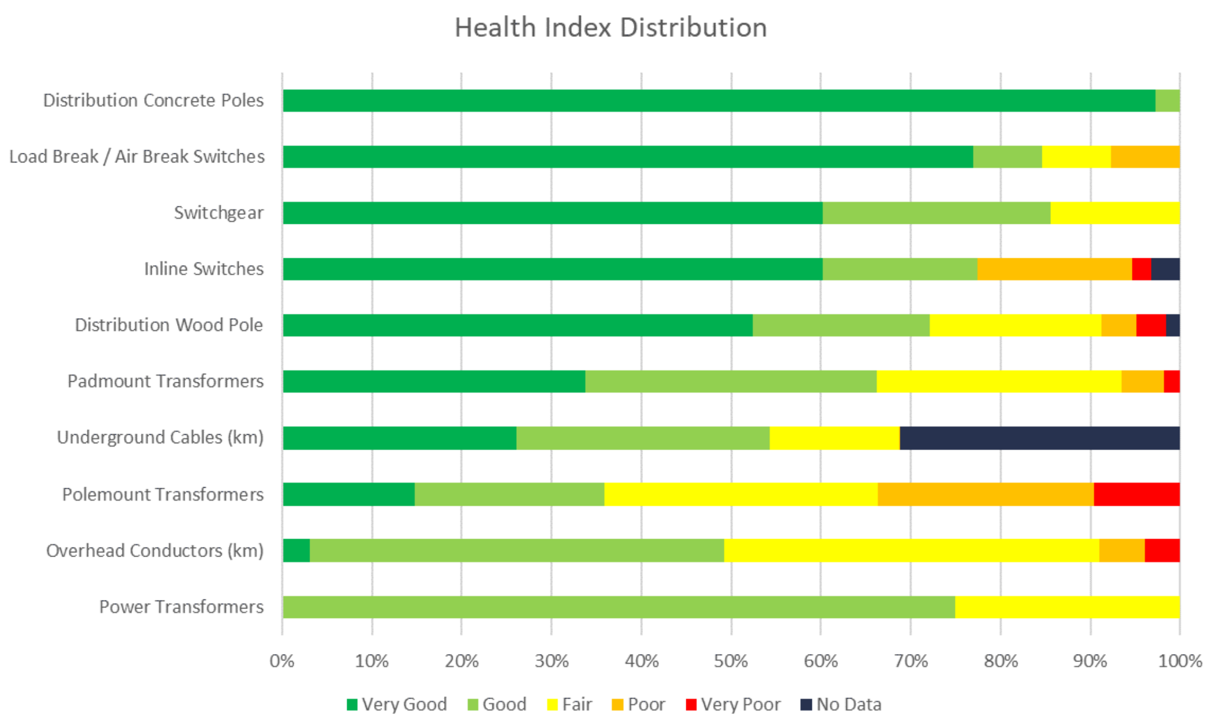


Figure 6-1: Health Index Results

METSCO recommends that OHL continue to work on mitigating the existing data gaps cost-effectively, such that more degradation parameters can be assigned actual grades, thus expanding the sample size of HIs and capturing all possible degradation of the evaluated assets. OHL's testing, inspection, and maintenance programs are positioned to continue to capture this information using processes and technologies in place at their facility.

This concludes METSCO's report on the condition assessment performed for OHL. We wish the utility's staff all the best as they continue their system planning work and preparation for their upcoming rate filing.

7 Appendix A – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure 7-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over 10 years. Our founders are the pioneers of the first-ever Health Index methodology for power equipment in North America as well as the most robust high voltage risk-based analytics on the market today. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified experts to provide its service to OHL.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

8 Appendix B – Condition Parameters Grading Tables

8.1 Distribution Wood Poles

Table 8-1: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 55 years
E	Over 55 years

Table 8-2: Criteria for Surface Decay

Condition Rating	Corresponding Condition (inch)	Decay Resistograph Test	Description
A	0	[0-2] %	There is no wood rot or other damage to the pole and the pole is in like-new condition
B	Between 0 to less than 0.5	(2-13] %	Minor wood rot and/or minor damage to the pole does not require corrective action. Minimal deterioration
C	Between 0.5 to less than 1	(13-36] %	There is significant wood rot and/or damage, requiring planned corrective action. Significant deterioration
D	Between 1 to less than 1.5	(36-59] %	There is major wood rot, and/or damage requiring immediate emergency repairs. Major deterioration
E	1.5 and more	Greater than 59 %	Wood rot or damage is beyond repair

Table 8-3: Criteria for Defects

Condition Rating	Corresponding Condition (inch)	Decay Resistograph Test	Description
A	None	[0-2] %	No signs of any defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion,
B	Between 0 to 0.5	(2-10] %	Minor signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion
C	0.5 and Passed Test	(10-16] %	Significant signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion
D	0.5 and Failed test	(16-20] %	Major signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion
E	0.5 and more	Greater than 20 %	Serious signs of defects on the wood pole due to cracking, insect infestation, vandalism, vehicular accidents, electrical burns, lightning, water or ground rot, soil erosion

8.2 Concrete Poles

Table 8-4: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	Over 50 years

Table 8-5: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No signs of any defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
B	Signs of minor defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
C	Signs of significant defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
D	Signs of serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking
E	Signs of very serious defects on the concrete pole due to vandalism, vehicular accidents, electrical burns, or cracking

8.3 Overhead Primary Conductor

Table 8-6: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 30 years
C	31 to 50 years
D	51 to 70 years
E	Over 70 years

Table 8-7: Criteria for Small Risk Conductor

Condition Rating	Corresponding Condition
A	Absence of small-sized conductors
E	Presence of small-sized conductors (#4 to #6 copper)

8.4 Underground Primary Cable

Table 8-8: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 25 years
C	26 to 35 years
D	36 to 45 years
E	Over 45 years

Table 8-9: Criteria for Historic Failure Rates

Condition Rating	Corresponding Condition
A	Less than 0.5 failure per 10 km in the last 5 years
B	0.5 to 1.0 failure per 10 km in the last 5 years
C	1.0 to 2.0 failures per 10 km in the last 5 years
D	2.0 to 4.0 failures per 10 km in the last 5 years
E	4.0 or more failures per 10 km in the last 5 years

8.5 Overhead/Pole Mount Transformer

Table 8-10: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years

Condition Rating	Corresponding Condition
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-11: Criteria for Peak Loading

Condition Rating	Component Condition
A	Peak load of less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

8.6 Underground Transformer

Table 8-12: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-13: Criteria for Peak Loading

Condition Rating	Component Condition
A	Peak load of less than 50% of its rating
B	Peak load of 50% to 75% of its rating
C	Peak load of 75% to 100% of its rating
D	Peak load of 100% to 125% of its rating
E	Peak load of greater than 125% of its rating

8.7 Load Break & Air Break Switch

Table 8-14: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-15: Criteria for Condition of Insulators and Blades

Condition Rating	Corresponding Condition
A	Support Insulators are not broken and are free of chips, radial cracks, flashover burns, copper splash and copper wash. Cementing and fasteners are secure. Blades are clean, free from corrosion, cracks, distortion, abrasion or obstruction. All fasteners are tight. No visible evidence of looseness, loss of adjustment, or excess bearing wear.
B	Support Insulators are not broken, however there are some minor chips and cracks. No flashover burns or copper splash or copper wash. Cementing and fasteners are secure. Minor signs of wear with respect to the above listed deficiencies.
C	Support Insulators are not broken, however there are some major chips and cracks. Some evidence of flashover burns or copper splash or copper wash. Cementing and fasteners are secure. Significant signs of wear with respect to the above listed deficiencies, but the deficiencies are not critical to the safe operation of the switch.
D	Support Insulators are broken/damaged or cementing or fasteners are not secure. Blades are degraded requiring replacement during the next scheduled outage.
E	Support Insulators, cementing or fasteners are broken/damaged beyond repair. Blades are damaged/degraded beyond repair, requiring immediate replacement.

8.8 Inline Switch

Table 8-16: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-17: Connection Pitting

Condition Rating	Corresponding Condition
A	No pitting or corrosion on connection points or bolts, connectors and bolts are in like new condition
C	Low to moderate pitting and/or corrosion of connectors or bolts. Schedule maintenance on connectors and monitor switch
E	Severe pitting and/or corrosion of connectors or bolts. Replace switch immediately

Table 8-18: Insulator Condition

Condition Rating	Corresponding Condition
A	Insulator support has no cracks or signs of heat damage. The insulator is not warped and has no chips or tears on fins and is sitting tight against the support. Bolts connecting insulator to body are tight. There are no signs of flashover, the insulator is in like new condition

Condition Rating	Corresponding Condition
E	Visible cracking or heat damage of support. Insulator is pulling apart from support. Signs of flashover and/or insulator has become warped. Bolts connecting insulator to body have become loose.

Table 8-19: Blade Condition

Condition Rating	Corresponding Condition
A	Blade is clean, free from corrosion, cracks, distortion or obstruction. All fasteners are tight, no visible looseness, loss of adjustment or excess wear
C	Significant signs of wear with respect to the above listed deficiencies, but are not critical to the safe operation of the switch
E	Blade or part of the operating mechanism is damaged/degraded beyond repair requiring immediate replacement

8.9 Power Transformer

Table 8-20: Criteria for DGA Results

Gas Condition	Gas Generation Rate		
	Low	Low to High	High
Condition 1	A	A	B
Condition 2	B	B	C
Condition 3	C	C	D
Condition 4	D	D	E

Table 8-21: Criteria for Load History

Condition Rating	Corresponding Condition
A	$LS \geq 3.5$
B	$2.5 \leq LS < 3.5$
C	$1.5 \leq LS < 2.5$
D	$0.5 \leq LS < 1.5$
E	$LS < 0.5$

Table 8-22: Criteria for Insulation Power Factor

Condition Rating	Corresponding Condition
A	$PF_{MAX} < 0.5$
B	$0.5 \leq PF_{MAX} < 1$
C	$1 \leq PF_{MAX} < 1.5$
D	$1.5 \leq PF_{MAX} < 2$
E	$PF_{MAX} \geq 2$

Table 8-23: Criteria for Oil Quality Tests

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
IFT [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>23 (1mm gap) >40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table 8-24: Criteria for Service Age

Condition Rating	Corresponding Condition
A	Less than 20 years
B	20 to 40 years
C	40 to 60 years
D	More than 60 years
E	-

Table 8-25: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	Station transformer is externally clean and corrosion free. All monitoring, protection and control, pressure relief, gas accumulation and silica gel devices, and auxiliary systems mounted on the station transformer are in good condition. No external evidence of overheating or internal overpressure. No sign of oil leaks and forced air cooling fully functional. Appears to be well maintained with service records readily available.
B	Normal signs of wear with respect to the above characteristics.
C	One or two of the above characteristics are unacceptable
D	More than two of the above characteristics are unacceptable – repairable.
E	More than two of the above characteristics are unacceptable – damaged beyond repair

8.10 Switchgear

Table 8-26: Criteria for Service Age

Condition Rating	Corresponding Condition
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	Over 40 years

Table 8-27: Criteria for Overall Condition

Condition Rating	Corresponding Condition
A	No signs of damage or cracks, no signs of rust or damage, asset and sub-components are clean and in good condition
B	Signs of minor damage or cracks, minor signs of rust or damage, minor signs of wear on sub-components
C	Signs of significant damage or cracks, significant signs of rust or damage, significant signs of wear on sub-components
D	Signs of serious damage or cracks, serious signs of rust or damage, serious signs of wear on sub-components
E	Signs of very serious damage or cracks, extreme rust or damage, extreme wear on sub-components

Appendix C – OHL's Distribution Maintenance Program

Orangeville Hydro

Energizing Our Community's Future

Distribution Maintenance Program

Revised by Rob Koekkoek on January 14, 2023

Table of Contents

1. Overhead Visual Inspection Program

1.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro overhead system. This program covers the inspection of:

- Poles/Supports
- Overhead transformers
- Switches and Protective Devices
- Hardware and Attachments
- Conductors and Cables
- Third party plant
- Vegetation Control

1.2 Inspection Schedule: The overhead system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

On-going inspection requires the entire system to be **reviewed every three years**.

For the purpose of this program, a minimum of **one third** of the overhead system will be inspected **annually**

The Overhead Visual Inspection Program will be completed during:

- Day to Day work activities
- Line Clearing Program
- Infrared Inspection Program
- Pole Testing & Inspection Program

1.3 Visual Inspection Expectations: It is expected that the visual inspection will identify obvious structural and electrical problems and hazards.

Where the inspection notices problems that require more detailed inspection arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

1.4 Corrective Action: The results of the visual inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed in the year that the inspection was completed. In this way a backlog of deficiencies will not occur.

1.5 Details to Include in Visual Inspection: For the various components of the overhead system the items listed below should be included in the visual inspection.

While this list is fairly detailed it cannot cover all conditions in the field.

While completing the visual inspections staff are encouraged to note any conditions they believe impact on the safety or integrity of the system.

1.5.1 Poles/Supports:
Bent, cracked or broken poles
Excessive surface wear or scaling
Loose, cracked or broken cross arms and brackets
Woodpecker or insect damage, bird nests
Loose or unattached guy wires or stubs
Guy strain insulators pulled apart or broken
Guy guards out of position or missing
Grading changes, or washouts
Indications of burning

1.5.2 Transformers:
Paint condition and corrosion
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators
Contamination/discolouration of bushings
Ground lead attachments
Damaged disconnect switches or lightning arresters
Ground wire on arresters unattached

1.5.3 Switches and Protective Devices:
Bent, broken bushings and cutouts
Damaged lighting arresters
Ground wire on arresters unattached

1.5.4 Hardware and Attachments:
Loose or missing hardware
Insulators unattached from pins
Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

1.5.5 Conductors and Cables:

Low conductor clearance
Broken/frayed conductors or tie wires
Exposed broken ground conductors
Broken strands, bird caging, and excessive or inadequate sag
Insulation fraying on secondary

1.5.6 Third Party Plant:
Attachment not secure
Infringing on clearances
Compromising access to electrical equipment
Unapproved/unsafe occupation or secondary use

1.5.7 General Conditions & Vegetation:
Leaning or broken "danger" trees
Growth into line of "climbing" trees
Accessibility compromised
Vines or brush growth interference (line clearance)
Bird or animal nests

2. Underground Visual Inspection Program

2.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro underground system. This program covers the inspection of:

- Pad Mounted Transformers & Switching Kiosks
- Vegetation and Right of Way.

2.2 Inspection Schedule: The underground system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

On-going inspection requires the entire system to be **reviewed every three years**.

For the purpose of this program **one third** of the underground system will be inspected **annually.**

The Underground Visual Inspection Program will be completed during:
- Day to Day work activities
- Infrared Inspection Program
- Padmounted Equipment Refinishing Program

2.3 Visual Inspection Expectations: It is expected that the visual inspection will identify obvious structural & electrical problems and hazards.

Where the inspection notices problems that require more detailed inspection arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

2.4 Corrective Action: The results of the visual inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed in the year that the inspection was completed. In this way a backlog of deficiencies will not occur.

2.5 Details to Include in Visual Inspection: For the various components of the underground system the items listed below should be included in the visual inspection.

While this list is fairly detailed it cannot cover all conditions in the field.

While completing the visual inspections staff are encouraged to note any conditions they believe impact on the safety or integrity of the system.

2.5.1 Pad Mounted Transformers and Switching Kiosks:

Paint condition and corrosion
Placement on pad or vault
Check for lock and penta bolt in place or damage
Grading changes
Access changes (Shrubs, trees, etc.)
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Lid damage, missing bolts, cabinet damage
Cable connections
Ground connections
Nomenclature
Animal nests/damage
General conditions

2.5.2 Vegetation and Right of Way:

Accessibility compromised
Grade changes that could expose cable
Excessive vegetation on right of way

3. Substations Visual Inspection Program:

3.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro substations. This program covers the inspection of:

- Distribution Substations
- Customer Specific Substations

3.2 Schedule: Each substation will be inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

Inspection Schedule			
	Outdoor Open	**Outdoor Enclosed**	**Indoor Enclosed**
Distribution Station	1 month	Annually	Annually
Customer Substation	Annually	3 Years	3 Years

At the time of this report, Orangeville Hydro owns four Outdoor Open Distribution Stations and no Customer Specific Substations.

Orangeville Hydro's Line and Engineering Staff will complete the monthly visual inspections.

Additional visual inspections will be completed by a Contractor twice per year to assist Orangeville Hydro. The Contractor will also take oil samples to complete *Dissolved Gas Analysis* and *Chemical Analysis* of each substation transformer.

3.3 Visual Inspection Expectations:
It is expected that the visual inspection will identify obvious structural & electrical problems and hazards.

Where the inspection notices problems that require more detailed inspection arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

3.4 Corrective Action: The results of the visual inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed in the year that the inspection was completed. In this way a backlog of deficiencies will not occur.

3.5 Field Records: Each inspection will require a record to be generated to fully record the results of the inspection, any follow up action required and a record that the action was taken.

The records will also form a source of information for planned rehabilitation of the substations over time.

For the purpose of recording the inspections the "Field Inspection: Substation Condition Report" form will be used (See form in Appendix A1).

3.6 Filing of Records: The Record of Field Inspection form will be kept on file for a two year period. These records will be maintained in the Manager of Operations and Engineering's Office.

The information from the Record of Substation Inspection will be transferred to the appropriate file in the maintenance program.

While the computer file forms a convenient reporting and analyses tool the Record of Substation Inspection will be maintained as the official record.

3.7 Details to Include in Visual Inspection: For the various components of the substations the items listed below should be included in the visual inspection.

While this list is fairly detailed it cannot cover all conditions in the field.

While completing the visual inspections staff are encouraged to note any conditions they believe impact on the safety or integrity of the system.

3.7.1 Transformers:
Paint condition and corrosion
Phase indicators and unit numbers match operating map (where used)
Leaking oil
Flashed or cracked insulators
Contamination/discolouration of bushings
Ground lead attachments

3.7.2 Switches and Protective Devices:
Bent, broken bushings and cutouts
Damaged lighting arresters
Ground wire on arresters unattached

3.7.3 Hardware and Attachments:
Loose or missing hardware
Insulators unattached from pins

Conductor unattached from insulators
Insulators flashed over or obviously contaminated (difficult to see)
Tie wires unraveled
Ground wire broken or removed
Ground wire guards removed or broken

3.7.4 Switchgear:

Paint condition and corrosion
Placement on pad or vault
Check for locks
Grading changes
Leaking oil

3.7.5 Vegetation and Right of Way:

Accessibility compromised
Grade changes that could expose cable
Leaning or broken “danger” trees in proximity of station
Growth into line of “climbing” trees
Vines or brush growth interference (line or fence clearance)
Bird or animal nests

3.8 Cost Tracking:

3.8.1 **Inspection Labour** will be tracked using 50160
3.8.2 **Inspection Supplies & Expenses** will be tracked using 50170
3.8.3 **Maintenance Labour, Supplies, and Expenses** will be tracked using 51140
3.8.4 **Capital Improvements** will be tracked using 18200

4. Substation Preventative Maintenance:

4.1 Introduction: This program outlines the detailed inspection, testing, recording and follow up actions associated with the Orangeville Hydro Substation Maintenance. This program covers the:

- Testing of Substation Transformers
- Arrestor testing
- Protection Testing and Maintenance
- General station maintenance

4.2 Maintenance Schedule: The substations maintenance will be completed on each station once every eight years. With the current population of substations (4 stations) one substation will be maintained every other year.

Station	Last Maintenance	Planned Maintenance
MS2	2022	2028 (unless decommissioned prior)
MS3	2018	2024
MS4	2021	2026

4.3 Maintenance Expectations: To perform the scheduled maintenance on each station a services agreement will be provided from a substation maintenance contractor.

Conditions of the contract will require the following testing to be completed:

1. Inspect, clean and service the following components (including insulators and stand-offs):
   - Main HV disconnect switch and secondary fused switches in metal clad gear in station. Adjust switch operations as required.
   - Contact surfaces, coat with a non-oxidizing agent and lubricate the pivot points.
   - Primary fuses – coat with non-oxidizing agent. Perform contact resistance tests on switch and fuse contacts.
   - Verify fuse link sizes - All insulators and bushings in structure and enclosure to be inspected and tested

2. Inspect and perform insulation resistance tests on Lightning Arresters mounted on 44kV feeder on tower structure and any that may exist on the secondary feeders either in the gear or cable end on poles.

3. Inspect station grounding. Perform a three-point ground resistance test. Inspect enclosures to ensure they meet ESA requirements. Pull major weeds, etc as required, to meet ESA requirements.

4. Fully test and inspect main distribution transformer. Tests to include:

a. Dielectric absorption (insulation resistance test) (3-10 min. tests consisting of: High to Low and Ground, Low to High and ground, High and Low to Ground)
b. Capacitance and dissipation factor
c. Turn to turn ratio test. (exercise tape changer and perform ratio test on each tap position)
d. Winding Resistance Test

5. Secondary gear would be inspected throughout and cleaned plus visual checks. Switches would be exercised and contacts on fuses and switches cleaned. Tests of each cell to include contact resistance testing of fuse and switch contacts. Insulation resistance testing of gear at 5000 volts dc. Verify operation of cell heaters in gear and demand load meter operations. Test distribution lightning arresters in gear if present and if not recommendations would be made to add.

6. Secondary feeder testing to include Polarization Index (PI) testing (10 minute per cable nondestructive test).

The inspection is followed up with a report on findings and recommendations.

4.4 Corrective Action: The results of the maintenance and testing will be utilized to schedule any repair work required or, where appropriate, capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed will be filed in the Engineering Office.

The expectation is that corrective action will be completed on the schedule indicated in the maintenance report.

4.5 Maintenance Records: Each maintenance will require a record to be generated to fully record the results of the maintenance and testing, any follow up action required and a record that the action was taken. The records will also form a source of information for planned rehabilitation or replacement of the substation equipment over time.

4.6 Filing of Records: The reports provided by the contractor and any follow up action will be maintained in the substation files in the Manager of Operations and Engineering's Office. Maintenance and test results from previous years will be maintained for 7 years to form a history of the condition of the substation.

4.7 Cost Tracking:

4.7.1 Maintenance Labour, Supplies, and Expenses will be tracked using 51140

4.7.2 Capital Improvements will be tracked using 18200

5. Line Clearing Program:

5.1 Introduction: Maintaining lines free from interference of vegetation and other obstructions is an important element to ensure the safety and reliability of the distribution system.

This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro line clearing program. This program covers the:

- Inspection of distribution system
- Line clearing activities

5.2 Inspection Schedule: Line clearance inspections have been incorporated into the other inspection programs such as Pole Testing and Infrared Inspections, as well as, during the course of regular work. Any areas of reduced clearance will be either resolved or noted and reported to the Manager of Operations & Engineering.

Furthermore, the Zone that is scheduled for Line Clearing will be patrolled during the Clearing Activities.

5.3 Inspection Expectations: Inspections will determine locations where:

- Vegetation is in contact with secondary conductors
- Vegetation is within 2.0 meters of primary conductors
- Vegetation is in contact with or obstructs access to pad mounted equipment

5.4 Line Clearing Schedule: Line clearing will be done as required based on inspections and reports. Maintenance work orders will be issued as a result of field observations and inspections and the work scheduled accordingly.

The priority of line clearing is:

1. Primary Express Feeders (44kV and 27.6kV)
2. Fused Three Phase Circuits (27.6kV, 12.5kV, and 4.16kV)
3. Single Phase Taps (16kV, 7.2kV, and 2.4kV)
4. Road side secondary bus
5. Rear lot construction secondary bus

Individual overhead services are not part of the annual program and will be cleared as required and in response to homeowners' requests.

The service area will be divided into three Zones for Line Clearing Activities. (see Appendix B1)

Zone	Orangeville	Grand Valley	Years
1 Blue	East of First Street East of John Street	South of Amaranth Street	2017, 2020, 2023
2 Yellow	North of Broadway West of First Street	North of Amaranth Street	2018, 2021, 2024
3 Red	South of Broadway West of John Street	-	2019, 2022, 2025

The service area will be divided into seven Zones for Rear Lot Clearing Activities. (see Appendix B2)

Zone	Orangeville	Years
1 Red	Westdale/McCarthy + Elizabeth (Odd)	2023
2 Yellow	Elizabeth (Even) + Zina (Odd) 6-10 McCarthy @ Lord Dufferin Centre 20-46 Third Street 4-21 Parkview Drive, Grand Valley	2024
3 Green	Zina (Even) + Broadway (Odd) Orange Court	2025
4 Blue	Victoria + Princess + Townline Dawson (Even) + Madison	2027
5 Purple	Princess + Caledonia + Dufferin + Cardwell (Odd) Erindale + Cardwell (Even)	2028
6 Pink	Dawson (Odd) +Shirley + Marion + South Park	2026
7 Grey	Centre Street (Odd) + Church Street + Hewitt Bythia (Odd) + William Street (Even)	2029

5.5 Field Records: Line clearing activities will be recorded on the appropriate work orders.

5.6 Filing of Records: The Work Order form will be kept in the Work Order System. These records will be maintained in the Engineering Office.

5.7 Cost Tracking:

5.7.1 Labour, Supplies, and Expenses will be tracked using 51350

6. Load Balance Program:

6.1 Introduction: This program outlines the measurement, recording and follow up actions associated with the Orangeville Hydro load balancing program. This program covers the:

- Recording of feeder loading
- Load balancing

6.2 Measurement Schedule: The feeder loads will be measured on an annual basis. Normally this activity will be undertaken during system peak loading. If there are system issues measurements may be taken more frequently.

6.3 Corrective Action: If the phase loading of the various feeders is out of balance by more than 10%, work orders will be issued for the transfer of load from the higher loaded phase to the lightly loaded phase.

Where loading measurements indicate that the feeder loading is reaching capacity levels transfer of load to feeders with more capacity will be undertaken.

Maintenance work orders will be issued to complete any load transfers.

6.4 Field Records: Load transfer activities will be recorded on the appropriate work orders.

6.5 Filing of Records: The Work Order form will be kept in the Work Order System. These records will be maintained in the Engineering Office.

6.6 Cost Tracking:

6.6.1 **Inspection Labour** will be tracked using 50160, 50200 & 50850

6.6.2 **Operation Labour, Supplies, and Expenses** will be tracked using 50200 & 50250

7. Overhead and Underground Rebuilds:

7.1 Introduction: This program outlines the annual process for the renewal of the Orangeville Hydro distribution system. This program covers the:

- Recording of system inspections
- Evaluation of system rehabilitation needs
- Planned rehabilitation projects

7.2 Planning Expectations: Annual recommendations will be made for capital work on the overhead and underground systems.

Recommendations will be made based on the results of the inspections throughout the year and on any special investigations completed to address specific concerns.

7.3 Rehabilitation Expectations: The expectation is to keep the general condition of the systems in good shape to prevent the need for extensive maintenance and to limit system outages due to failures. The amount of work recommended will vary depending on the conditions found in the field.

7.4 Rebuild Projects: Approved projects will be completed through the capital works program.

7.5 Project Records: Each project will require an approved design to be developed and recorded. Upon completion of the projects, “as constructed drawings” will be produced and the system drawings up-dated.

8. Infrared Inspection Program

8.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro Infrared Program. This program covers the inspection of:

- Overhead Transformers
- Overhead Switches and Protective Devices
- Overhead Primary Conductor Splices and Terminations
- Underground Express Primary Cable Termination and Elbows
- Padmounted Express Switchgear Cubicles
- Secondary Bus Connections

8.2 Inspection Schedule: The overhead primary system will be fully inspected on a schedule that meets the requirements of the Distribution System Code. For the purpose of this program the "urban" population density schedule in the Distribution System Code will be utilized.

On-going inspection requires the entire system to be **reviewed every three years**.

For the purpose of this program **all** of the overhead primary system will be inspected **annually.**

For the purpose of this program **all** of the express underground system will be inspected **annually.**

For the purpose of this program the infrared contractor shall provide a report of all thermal anomalies found by paper and digital format.

8.3 Infrared Expectations: It is expected that the infrared inspection will identify thermal anomaly conditions on the electrical distribution equipment that suggest an unwanted condition exists.

In addition to the Infrared Inspection, it is expected that a visual patrol will be completed. It is expected that the visual inspection will identify obvious structural and electrical problems and hazards; as identified in *Overhead Visual Inspection Program* and *Underground Visual Inspection Program* sections of this document.

Where the inspection notices problems that require more detailed inspection, arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

8.4 Corrective Action: The results of the infrared inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed within 12 months from the date that the inspection was completed. In this way a backlog of deficiencies will not occur.

8.5 Field Records: Each inspection will require a record to be generated to fully record the results of the inspection, any follow up action required and a record that the action was taken.

The records will also form a source of information for planned rehabilitation of the overhead system over time.

For the purpose of recording the inspections the Infrared Contractor shall provide a report for all thermal anomalies detected.

8.6 Filing of Records: The Infrared Contractor Report will be kept on file until the system is inspected on the next cycle. These records will be maintained in the Engineering Office.

8.7 Cost Tracking:

- **8.7.1 Inspection Labour** will be tracked using 50200 & 50400
- **8.7.2 Inspection Supplies & Expenses** will be tracked using 50250 & 50450
- **8.7.3 Maintenance Labour, Supplies, and Expenses** will be tracked using 51250, 51300, 51600 & 51500

9. Pole Testing & Inspection Program

9.1 Introduction: This program outlines the inspection schedule, recording and follow up actions associated with the Orangeville Hydro Pole Testing & Inspection Program. This program covers the inspection of:

- Orangeville Hydro Owned Poles
- Hardware and Attachments
- Third party plant
- Vegetation Control

This program covers the testing of:

- Orangeville Hydro Owned Wooden Poles

9.2 Testing & Inspection Schedule: Orangeville Hydro and/or a Contractor will Test & Inspect a minimum number of poles each year. All poles will be tested prior to retesting poles. This will ensure no poles are missed for an extended period of time.

Year	Minimum Quantity of Poles
2023	150
2024	150
2025	150
2026	150
2027	150
2028	150

9.3 Pole Testing & Inspection Expectations: It is expected that the pole testing & inspection will identify significant decay and degradation of the wood fibers.

Acceptable non-destructive test methods are Resitograph and Polux.

In addition to the Infrared Inspection, it is expected that a visual patrol will be completed. It is expected that the visual inspection will identify obvious structural and electrical problems and hazards; as identified in *Overhead Visual Inspection Program*.

Where the inspection notices problems that require more detailed inspection, arrangements will be made to perform the work in a safe manner with the results reported in the inspection forms.

9.4 Corrective Action: The results of the testing and inspection will be utilized to schedule any repair work required or where appropriate capital work on a planned basis.

Where the inspection determines an immediate hazard to the public immediate follow up action will be required.

Work orders will be issued for the repair work and when the work has been completed the work orders will be filed in the Engineering Office.

The expectation is that corrective action will be completed within 12 months of the inspection. In this way a backlog of deficiencies will not occur.

9.5 Field Records: Each inspection will require a record to be generated to fully record the results of the inspection, any follow up action required and a record that the action was taken.

The records will also form a source of information for planned rehabilitation of the overhead system over time.

For the purpose of recording the inspections, a Field Inspection: Poles Report shall be completed for all poles tested and inspected. (See form in Appendix A2)

The Contractor shall provide a Detailed Report with the test results for all poles that were considered to have failed the test.

9.6 Filing of Records: The Inspection and Testing Reports will be kept on file until the specific poles inspected again. These records will be maintained in the Engineering Office.

9.7 Cost Tracking:

- **9.7.1 Inspection Labour** will be tracked using 50200
- **9.7.2 Inspection Supplies & Expenses** will be tracked using 50250
- **9.7.3 Maintenance Labour, Supplies, and Expenses** will be tracked using 51250
- **9.7.4 Capital Improvements** will be tracked using 18300

10. Padmounted Equipment Refinishing Program

10.1 Introduction: This program outlines the schedule associated with the Orangeville Hydro Padmounted Equipment Refinishing Program. This program covers the refinishing of:

- Transformers
- Switching Cubicles (PME & KABARS)

10.2 Refinishing Schedule: Orangeville Hydro and/or a Contractor will refinish a minimum of 30 pieces of equipment annually.

10.3 Refinishing Expectations: It is expected that the refinishing process will remove damaged paint, remove surface rust by sanding/grinding/sand blasting, prime and paint the exterior of the equipment.

In addition to the refinishing, it is expected that a visual patrol will be completed. It is expected that the visual inspection will identify obvious structural and electrical problems and hazards; as identified in the *Underground Visual Inspection Program*.

Where the patrol notices problems that require more detailed inspection, arrangements will be made to perform the work in a safe manner with the results reported.

10.4 Cost Tracking:

10.4.1 Inspection Labour will be tracked using 50550

10.4.2 Maintenance Labour, Supplies, and Expenses will be tracked using 51500 & 51610

Appendix A1 – Field Inspection: Substation Condition Report

Orangeville Hydro, MS3

Created	2016-09-09 13:21:22 UTC by Lines Staff
Updated	2016-09-09 13:29:40 UTC by Lines Staff
Status	Condition is Acceptable

General Station Information

Station Ownership and ID	Orangeville Hydro, MS3

General Area and Fence Condition

Area outside of fence is clear of potential access or touch potential voltage hazards	Yes
No vegetation is present within fence area	Yes
Fence prevents unauthorized access	Yes
Barbed wire is in good condition	Yes
Fence grounding and bonding connections are in good condition	Yes
Required warning signage is visible on all sides of the fence	Yes

Equipment Condition

Transformer is in acceptable condition	Yes
Transformer oil level is acceptable	Yes
Transformer shows no signs of oil leaks	Yes
Switchgear is in acceptable condition	Yes
Lightning arresters are grounded and are in acceptable condition	Yes
Insulators are in acceptable condition	Yes

Urgent Concerns

Does the Inspector have any urgent concerns?	No

Inspector Information

Date of Inspection	2016-09-09
Name of Inspector	Derek Halls

Appendix A2 – Field Inspection: Poles Report

P0969

Created	2016-02-24 20:20:49 UTC by Rob Koekkoek
Updated	2016-04-12 18:27:37 UTC by Essex Energy
Location	43.92202778, -80.08497052
Status	Inspection Completed 2016

Pole Information

Pole Number	P0969
Owner	ORANGEVILLE HYDRO LIMITED
Height	50
Class	4
Manufacturer	Guelph Utility Pole Company
Material	WOOD
Wood Type	WESTERN RED CEDAR
Wood Treatment	BUTT ONLY
Usage	DISTRIBUTION

Pole Condition Record

Hollow pole sound when struck with hammer	No
Bent, cracked, damaged, or broken pole	No
Leaning pole in unstable soil	No
Woodpecker, bird nests, or insect damage	No
Pole number is missing	No
Resistorgraph Test Results	PASS

Guying and Hardware Condition Record

Loose or unattached guy wire or studs	No
Slack, broken, or damaged guys	No
Guy positioned too close to primary conductors or equipment	No
Guy strain insulators pulled apart or broken	No
Guy guards out of position or missing	No
Loose, cracked, or broken crossarms and brackets	No
Other problems requiring follow-up	No

Inspector Information

Inspector Comments	NO ISSUES
Inspection Date	2016-04-12
Inspector Name	Essex Energy Corporation

Appendix B1 – Tree Trimming Zones

Figure 1 - Town of Orangeville Tree Trimming Zones

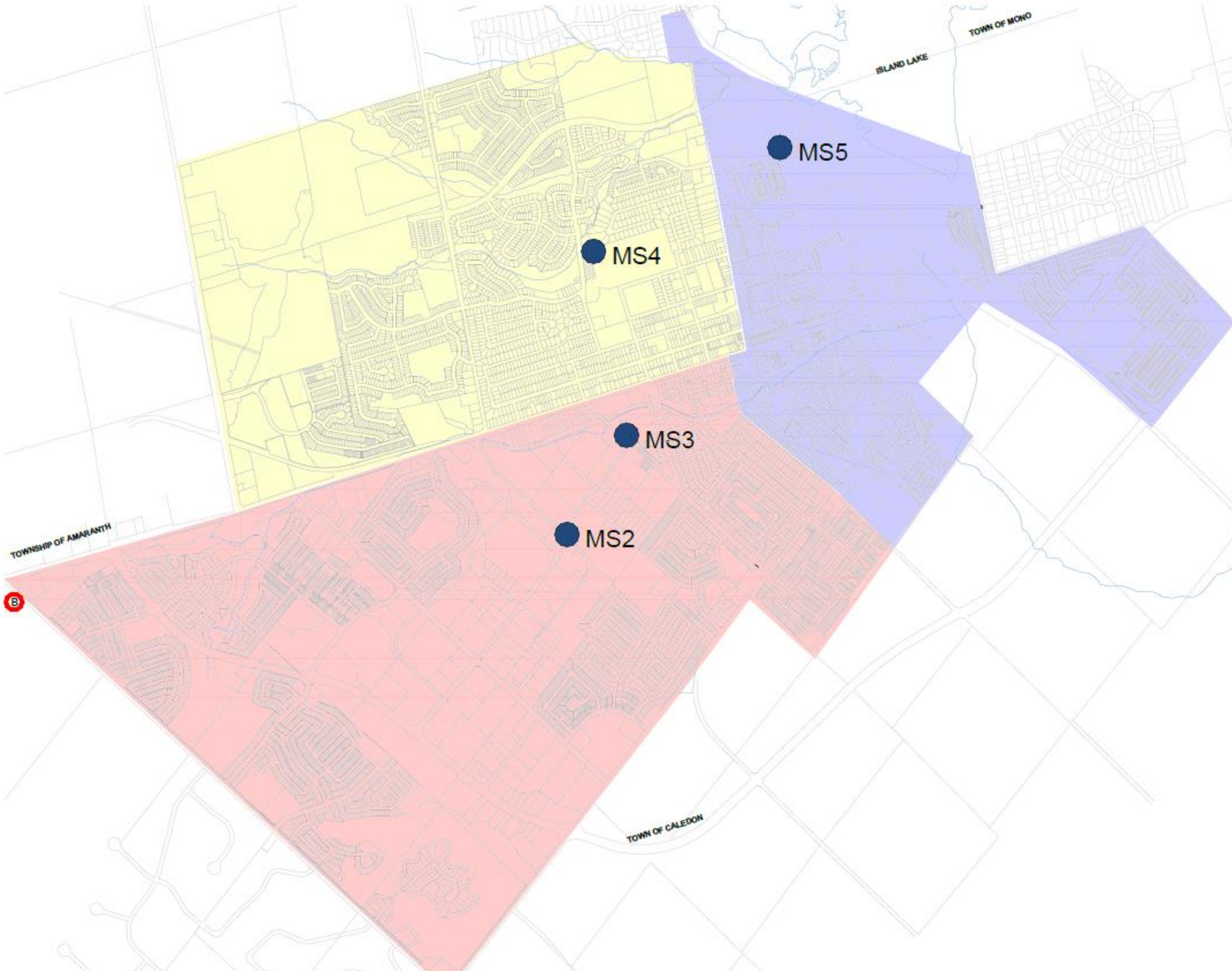
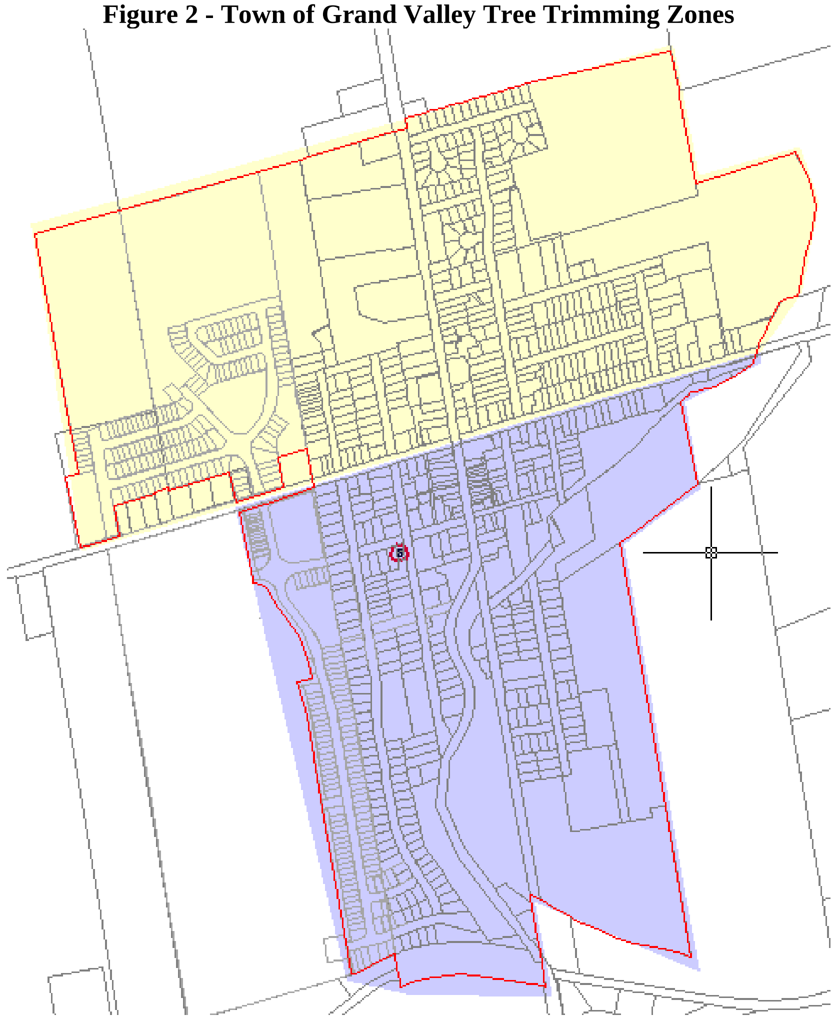


Figure 2 - Town of Grand Valley Tree Trimming Zones



Appendix B2 – Rear Lot Trimming Zones

Figure 3 - Town of Orangeville Rear Lot Zones

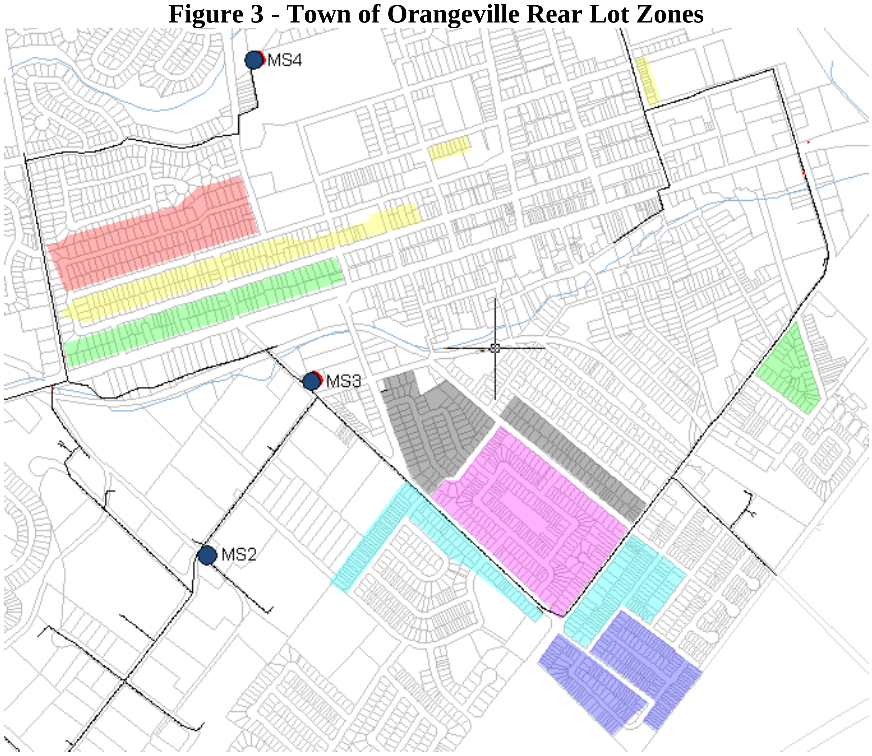
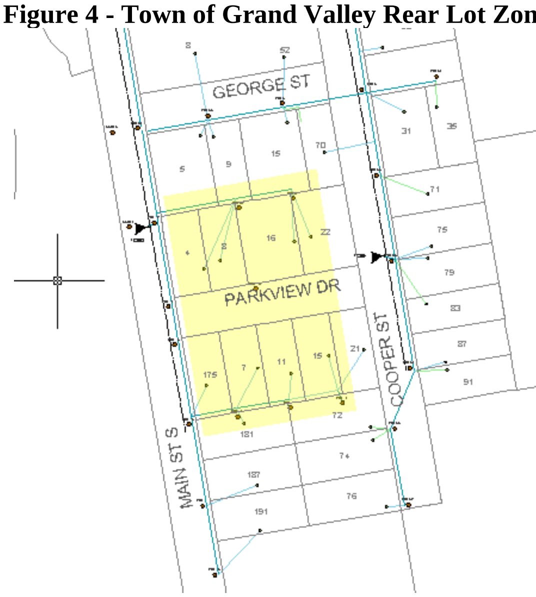


Figure 4 - Town of Grand Valley Rear Lot Zone



Appendix D – 2023 Orangeville Hydro Customer Satisfaction Report

ADVANIS for Orangeville Hydro

2023 Customer Satisfaction Survey

March 2023

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Deliverables

Advanis is pleased to provide **this report with results of the 2023 Customer Satisfaction study**.

- We include comparisons to previous years of the study, where applicable.

In addition to this report, you have access to **Advanis' Online Reporting Environment** (ORE) which allows you to:

- create charts and tables like those contained in this report
  - you will be able to do much more analysis than we had space for in this overall report (e.g., look at results comparing segments of the annual consumption index or the regions within your LDC, if applicable)
- review the verbatim responses to:
  - the open-ended question "Is there anything you would like your LDC to do to improve its services to you?"; and
  - questions where respondents could "specify" a response to one of your custom questions (if applicable).
  - Note that you can export the verbatim responses to Excel at the click of a button; and
  - search for key words or filter the results by different segments (e.g., customer type, region) or other questions in the survey.

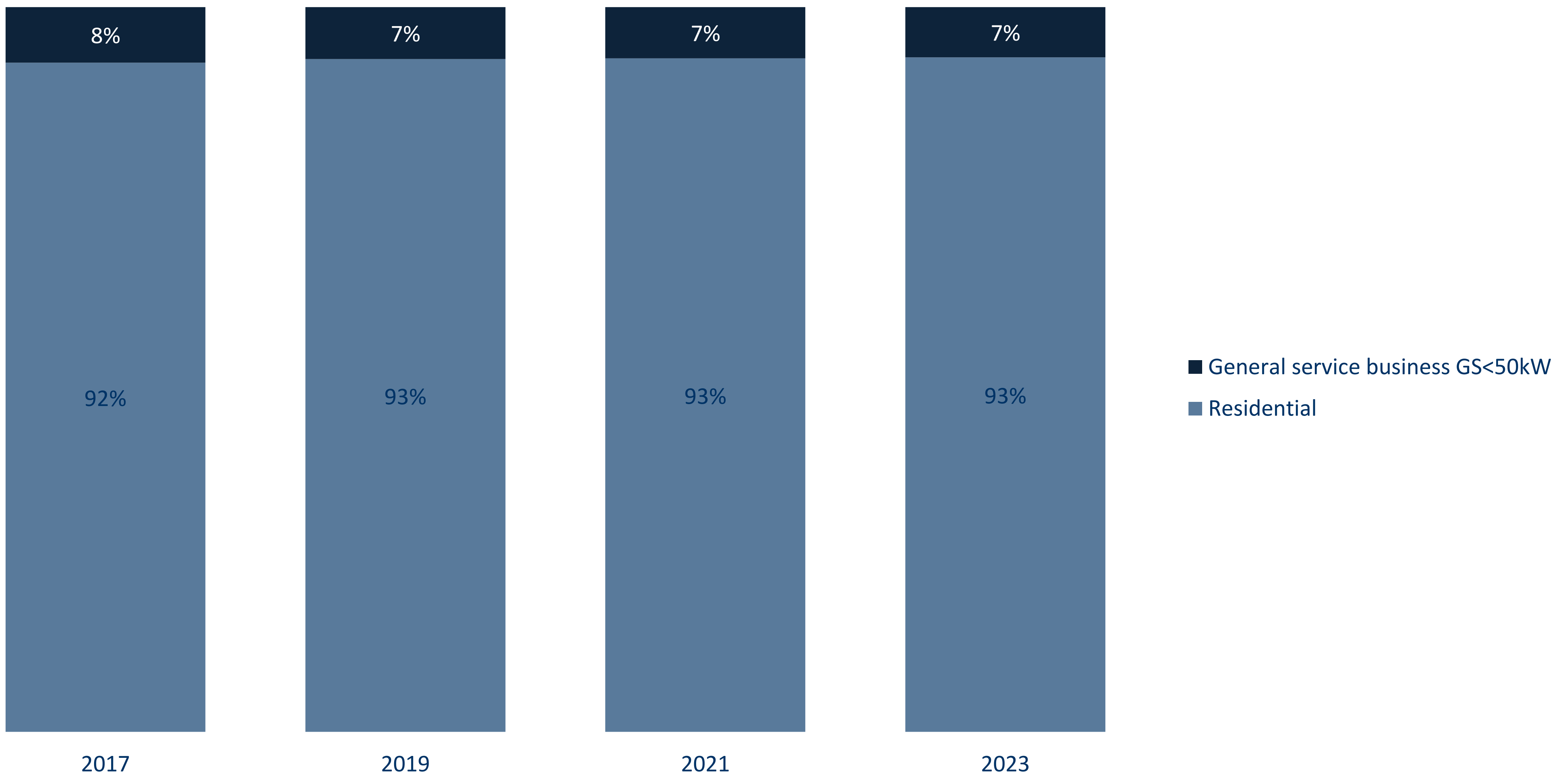
To access the ORE, visit this link: portal.advanis.net and enter your username in the format firstname_lastname. If you've forgotten your password, there is a link to reset it on the login page. If you have any questions, please contact Gary.Offenberger@advanis.net.

Contents

Lead Consultant: Gary.Offenberger@advanis.net // 780.229.1140

Customer (i.e., Survey Respondent) Profile

Customer Type - information provided by Orangeville Hydro



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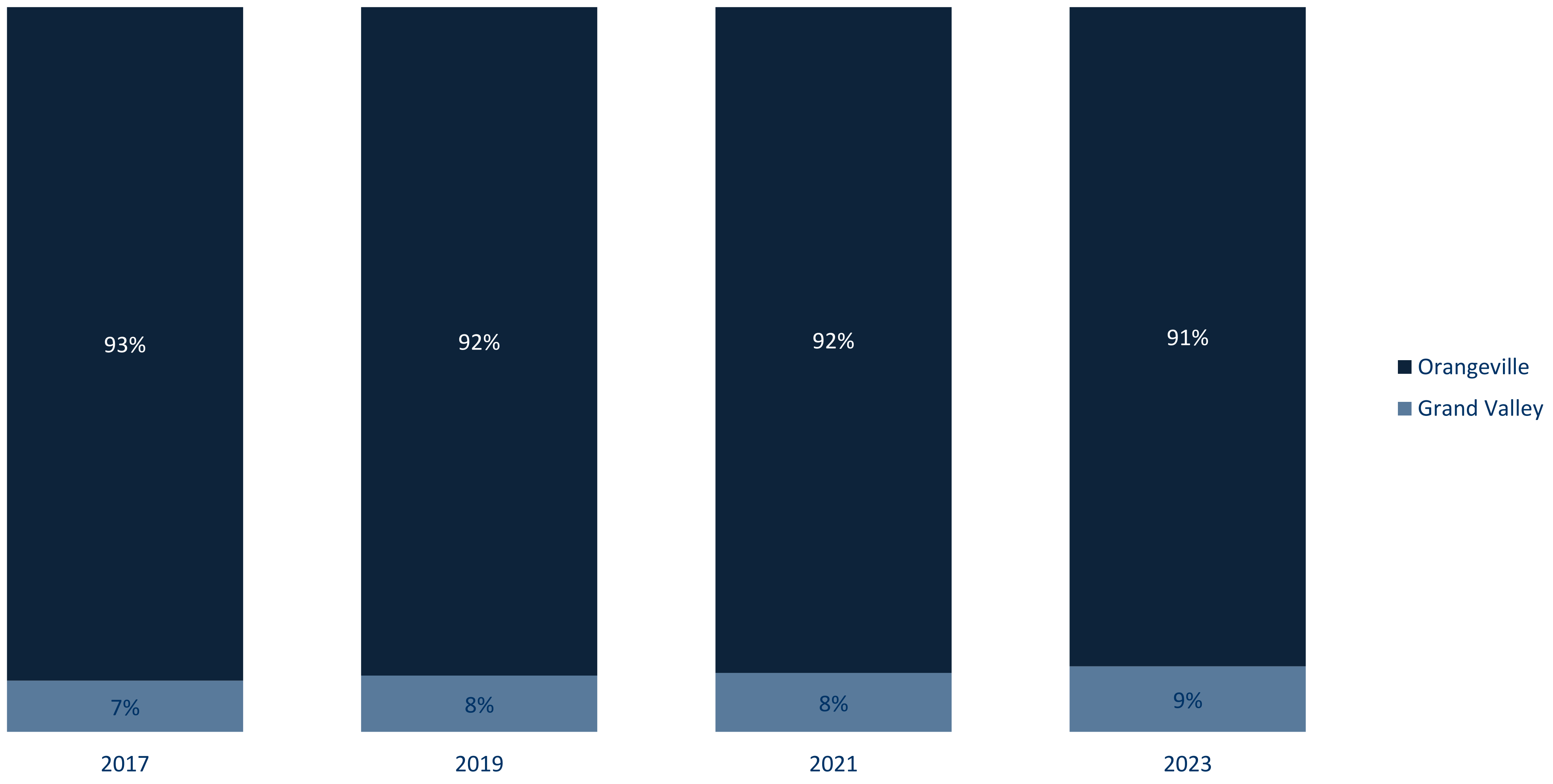
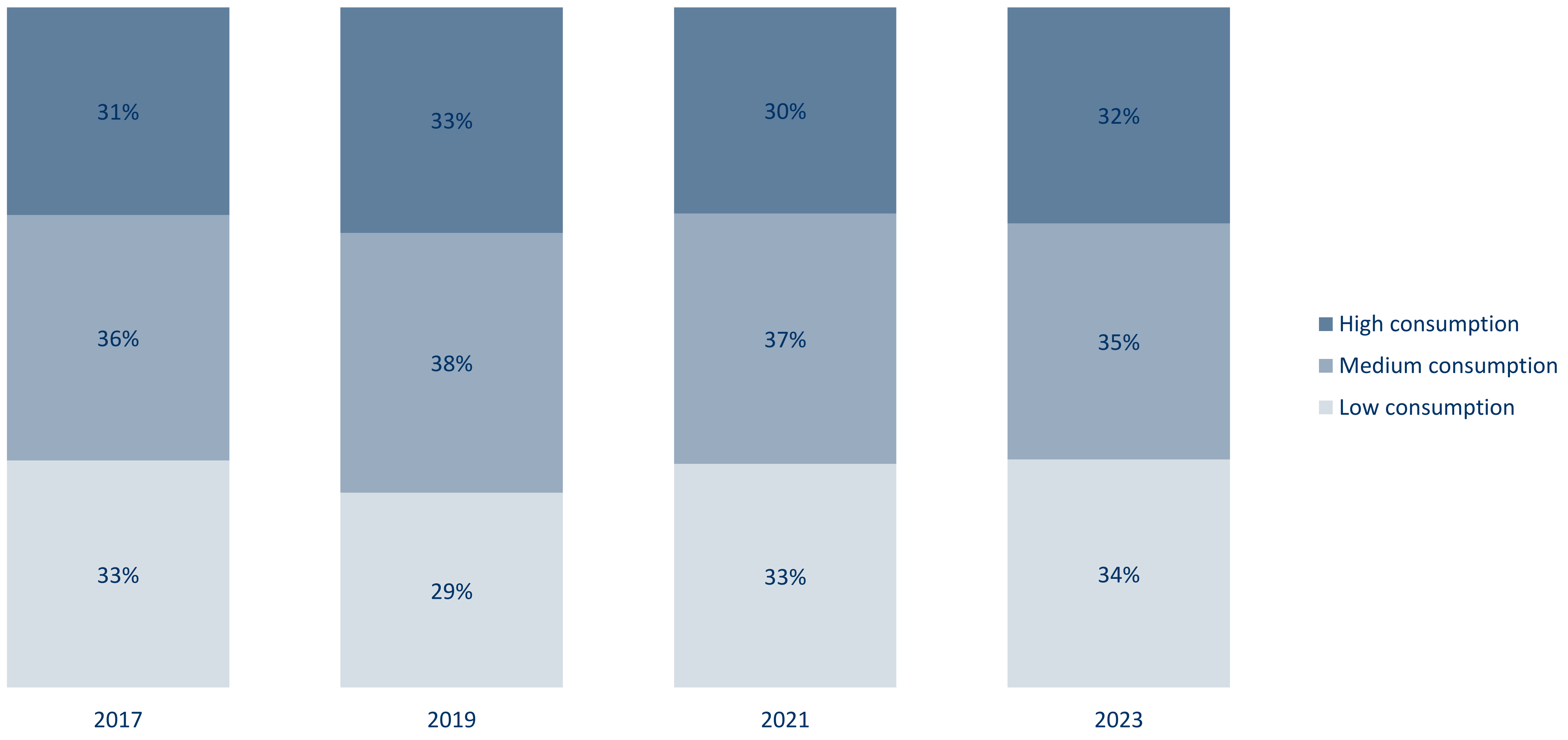
Filters: LDC: Orangeville Hydro

Region - information provided by Orangeville Hydro



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

Indexed score of annual consumption (Only have GS data for 2023 onwards) - information provided by Orangeville Hydro



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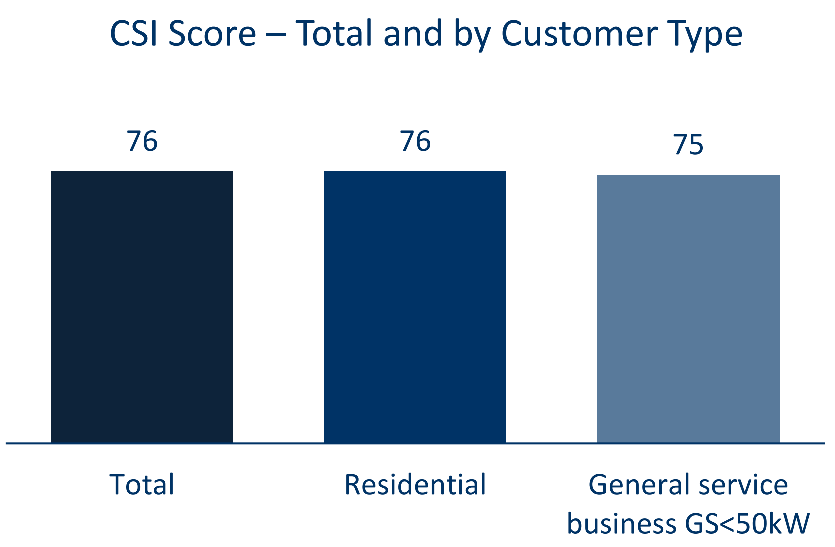
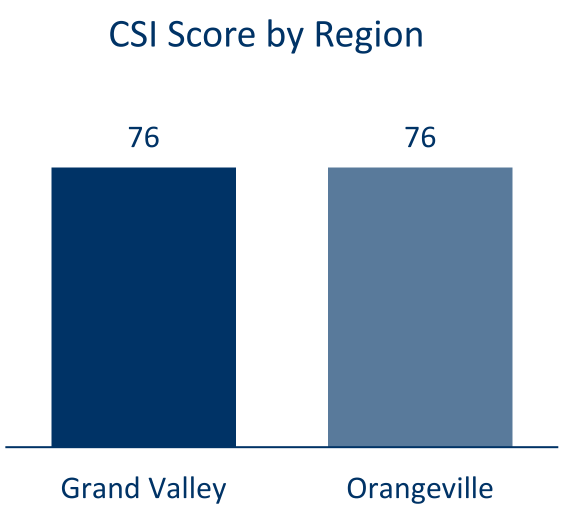
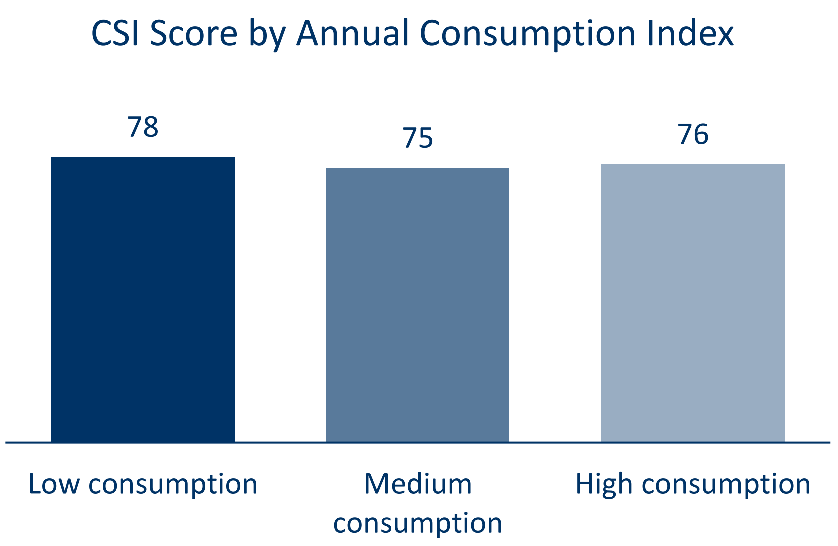
Filters: LDC: Orangeville Hydro

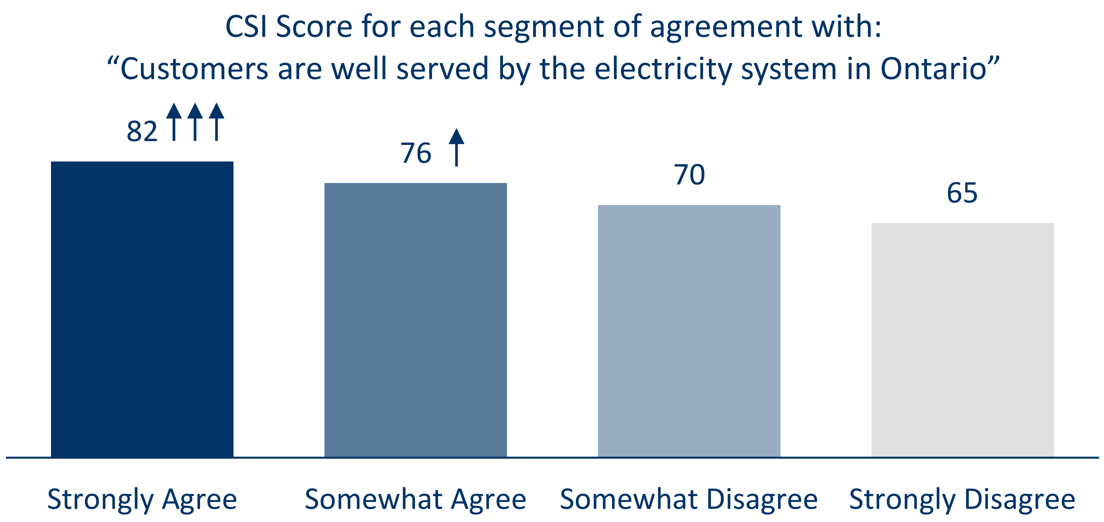
Customer Satisfaction Index Score – 2023 Results & Trend

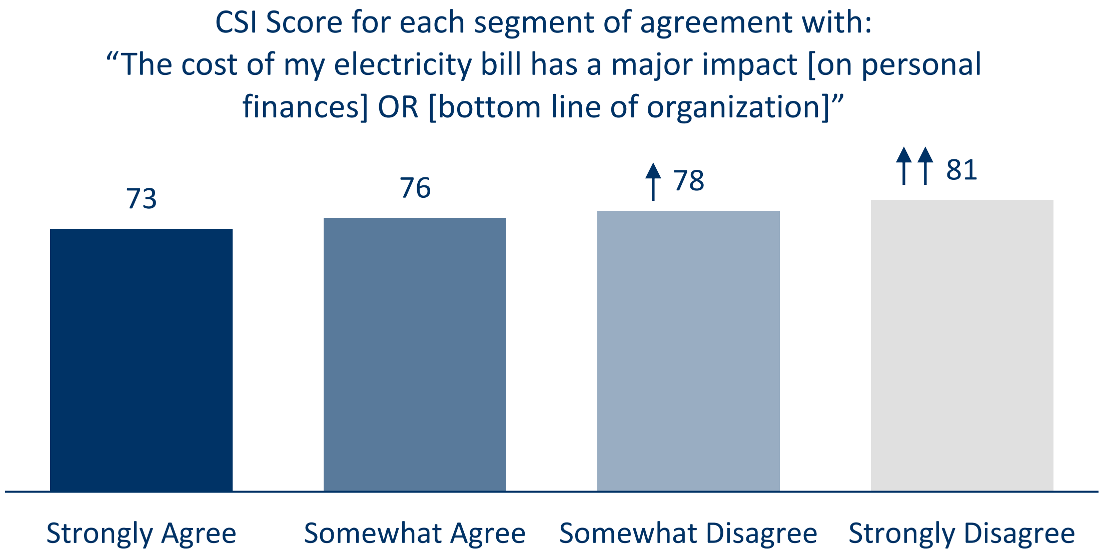
Customer Satisfaction Index: Orangeville Hydro for 2023











Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro
Note: Arrows denote statistically higher than other segment(s) at 95% confidence level; sometimes an apparent difference is not statistically significant because of low base size in a segment

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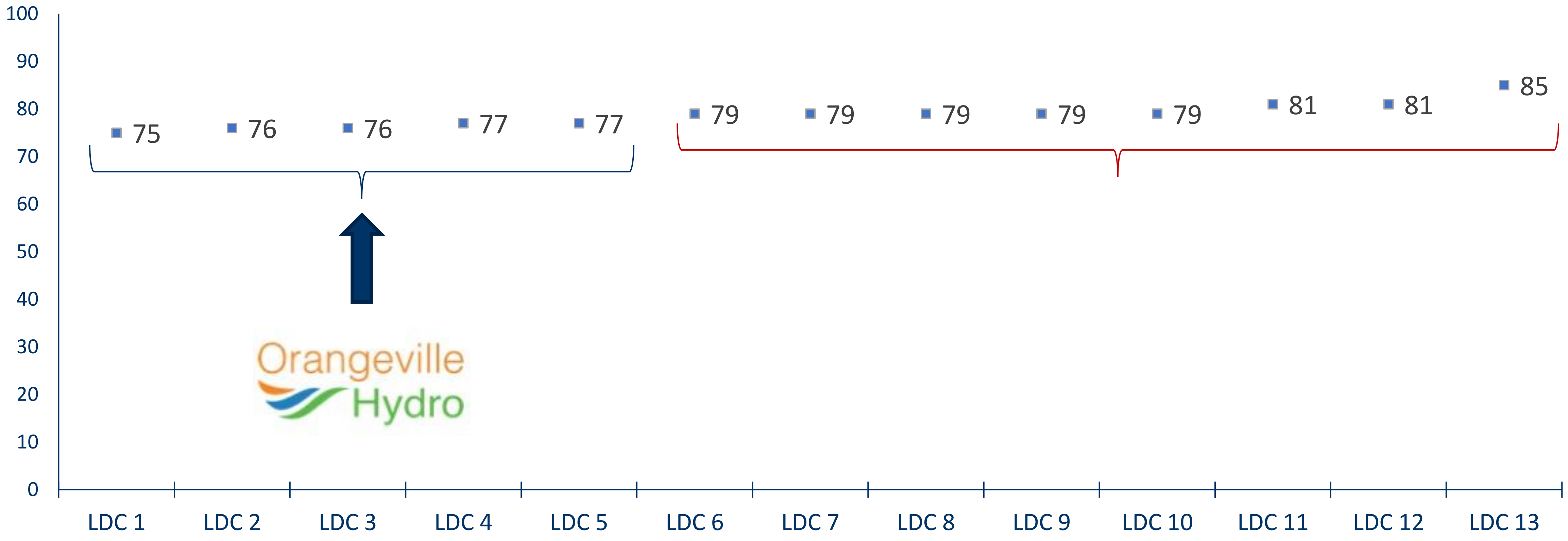
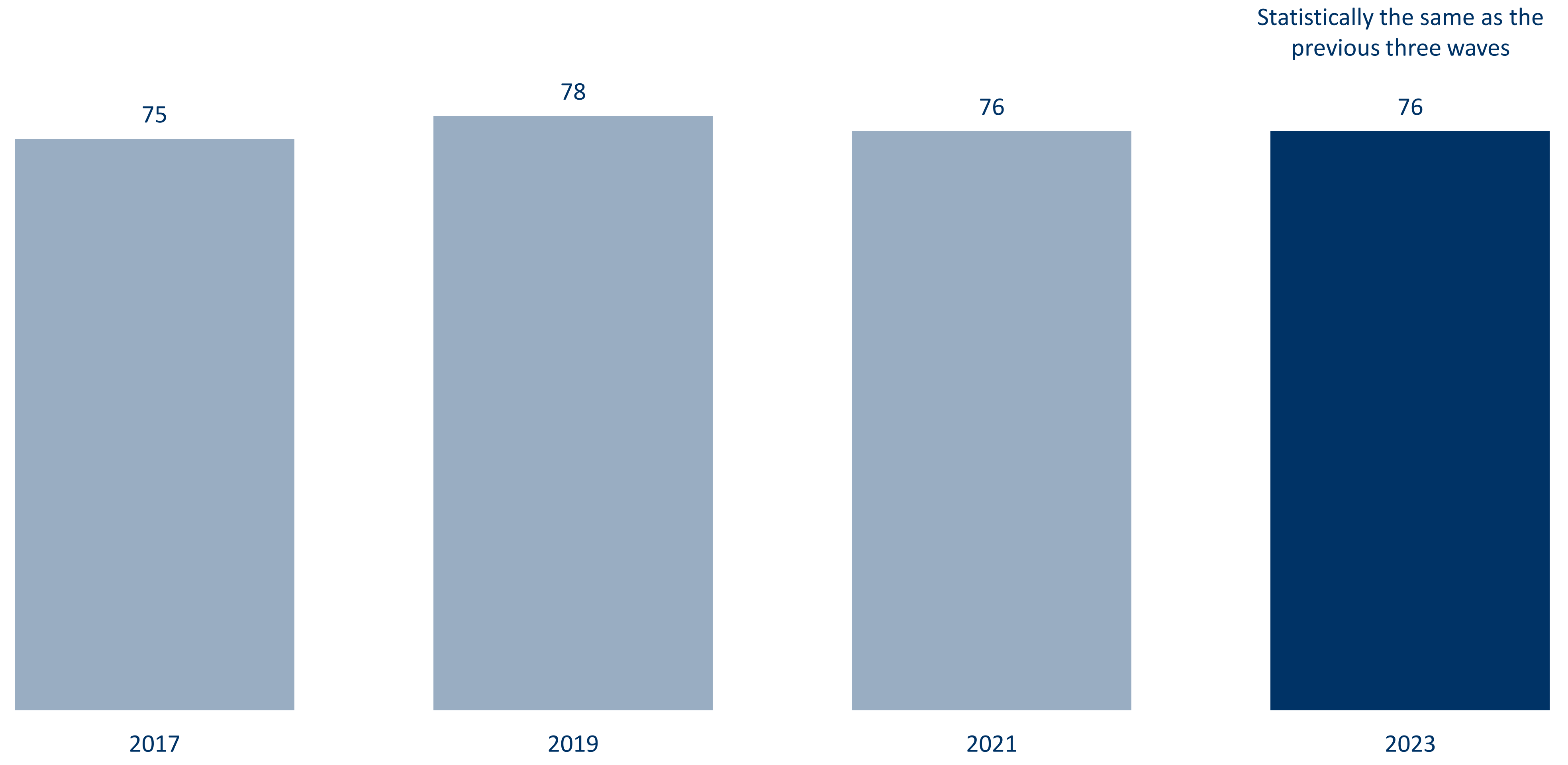
Customer Satisfaction Index: Compared to Other CHEC Members

- In 2023, Orangeville Hydro's score of 76 is *statistically* the same as that of 4 other LDCs.
- Orangeville Hydro's score is *statistically* lower than that of 8 other LDCs.



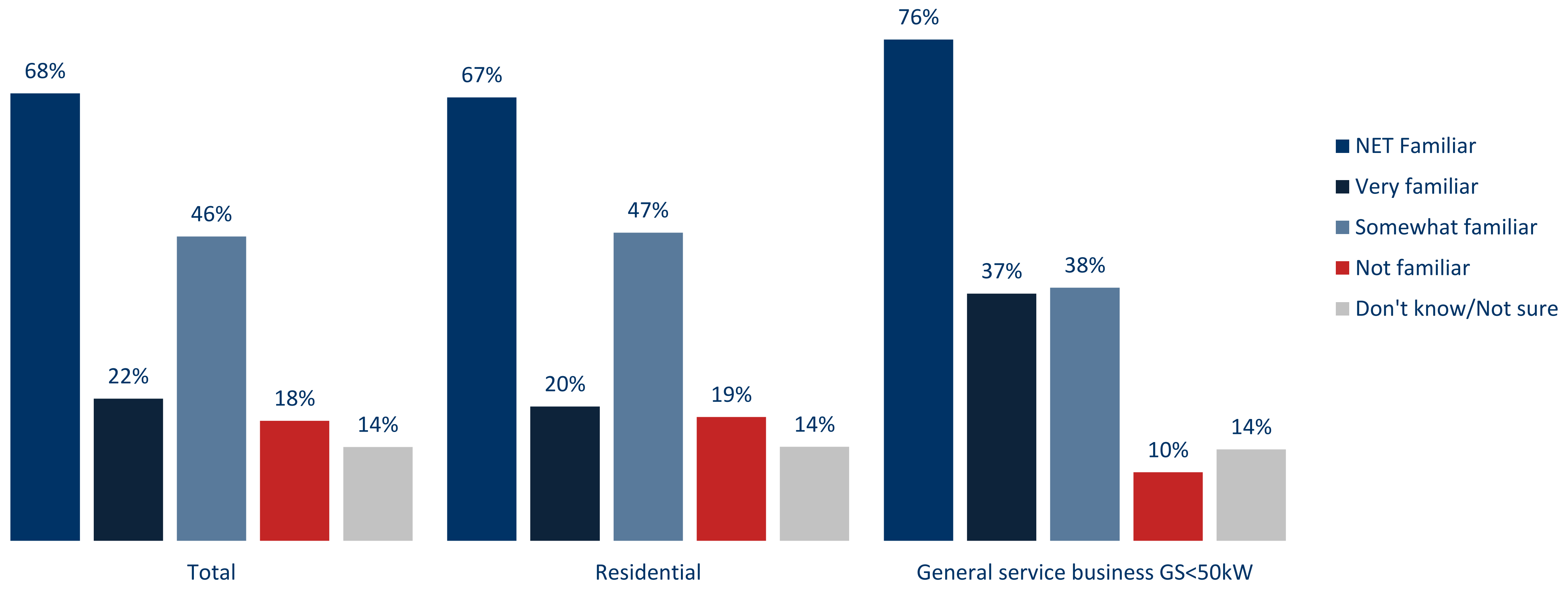
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023
Note: Statistical differences at 95% confidence level; sometimes an apparent difference is not statistically significant because of low base size in a segment

Orangeville Hydro's Customer Satisfaction Index by Year



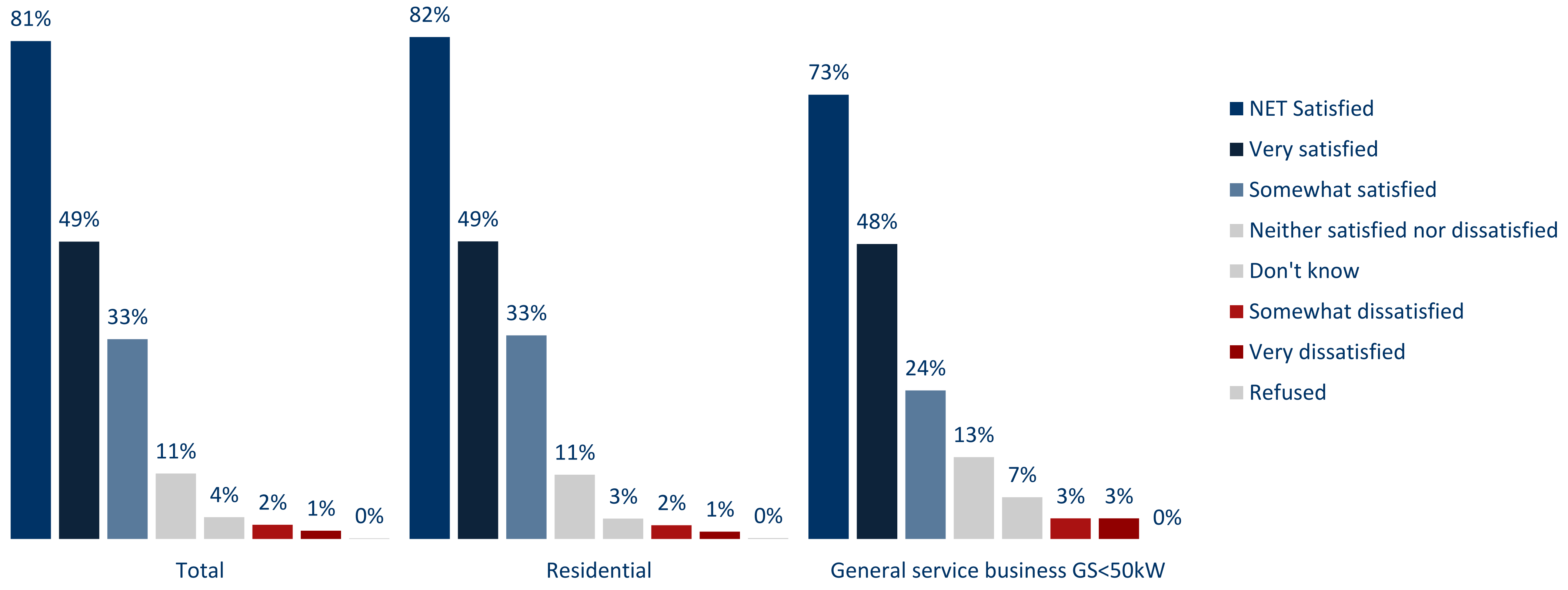
Core (OEB) Survey Questions – 2023 Results

How familiar are you with Orangeville Hydro, which operates the electricity distribution system in your community?



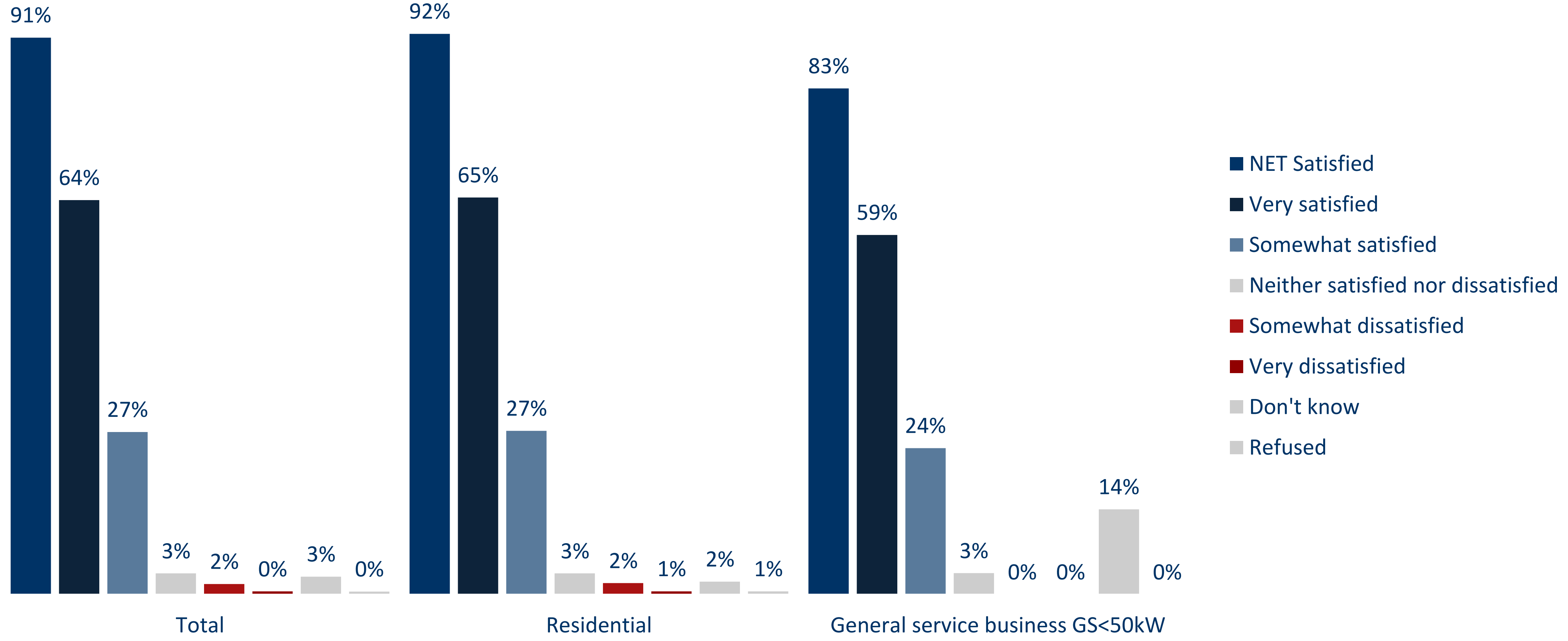
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

Thinking specifically about the services provided to you and your community by Orangeville Hydro, OVERALL, how satisfied are you with the services that you receive?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

How satisfied are you with the electrical service that you receive from Orangeville Hydro - based on the RELIABILITY of your electrical service as judged by the number of outages you experience?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

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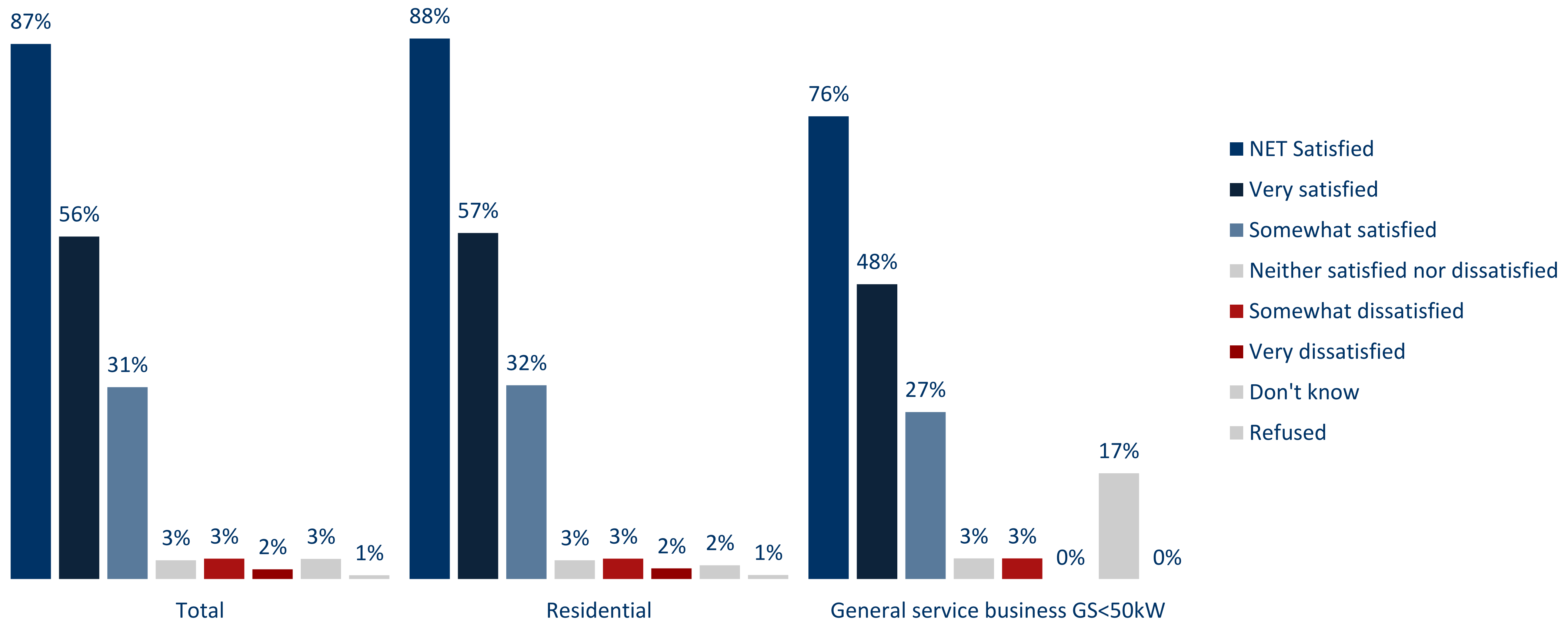
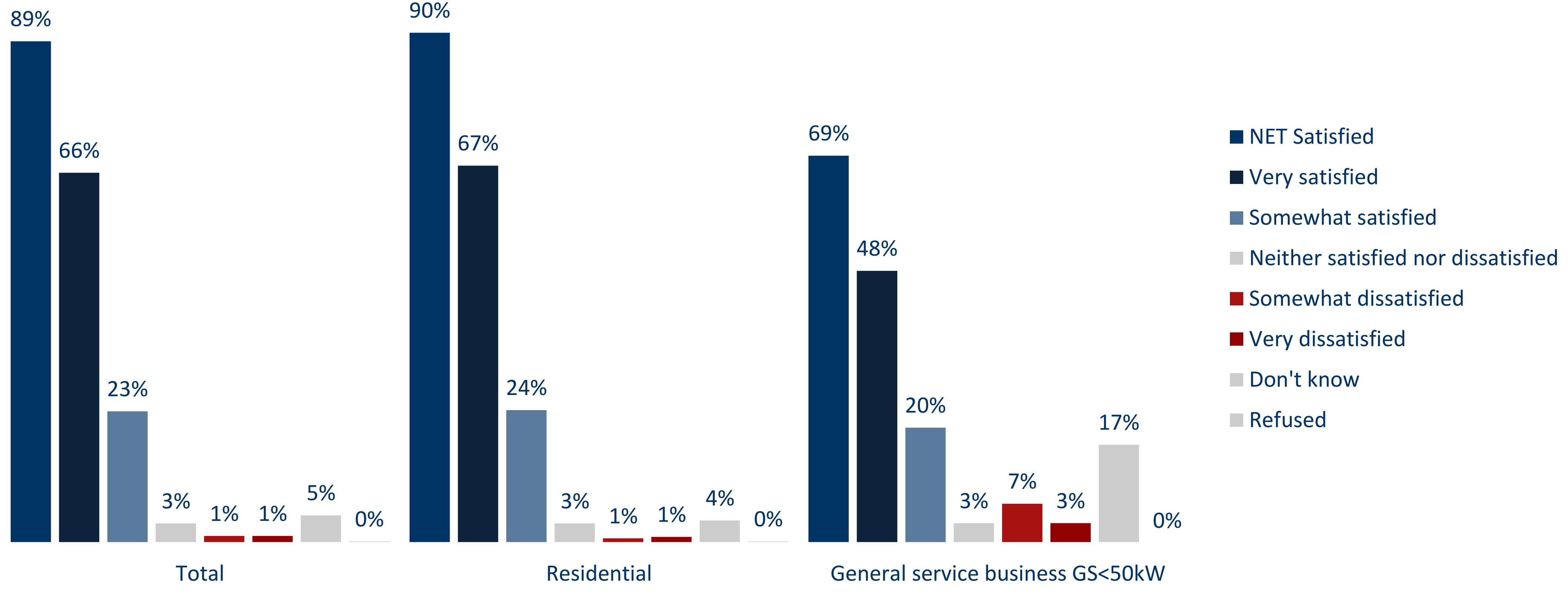
How satisfied are you with the electrical service that you receive from Orangeville Hydro - based on the amount of TIME IT TAKES TO RESTORE POWER when outages occur?



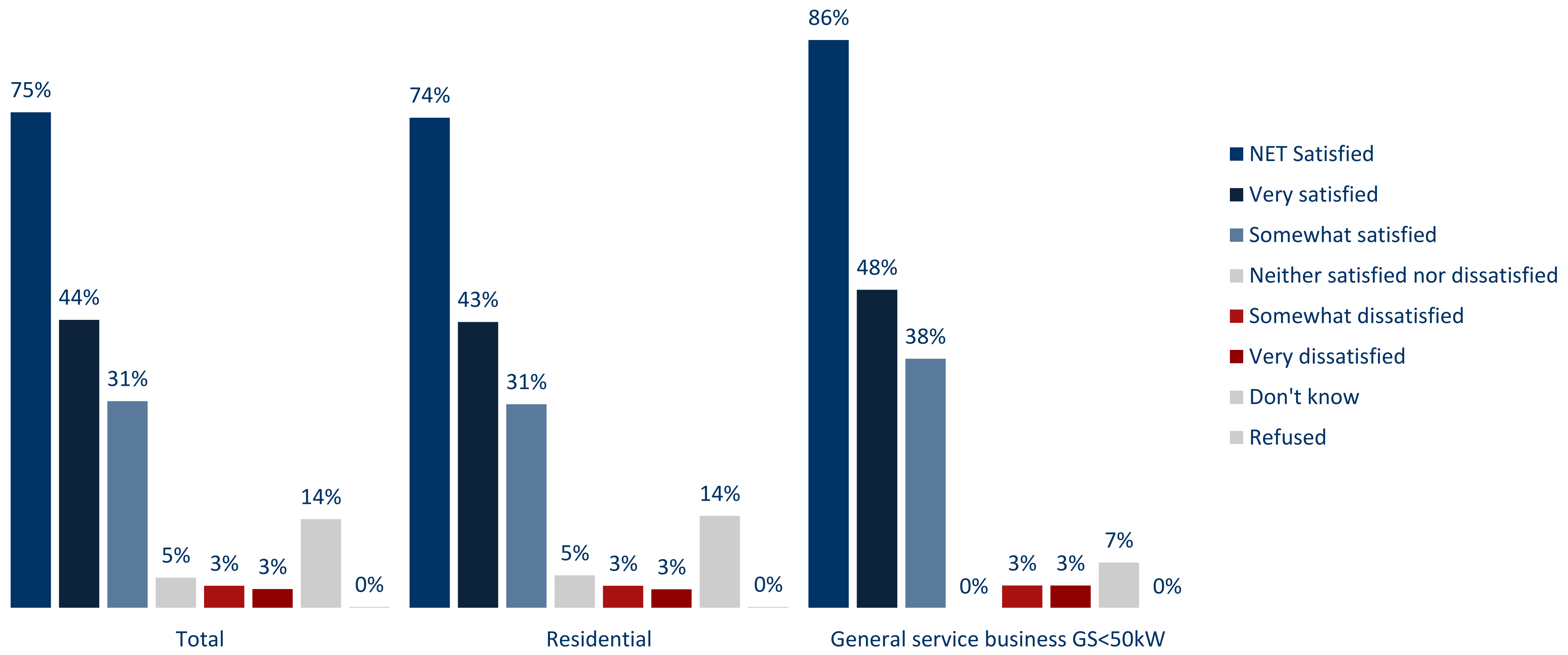
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

How satisfied are you with the electrical service that you receive from Orangeville Hydro - based on the QUALITY OF THE POWER delivered to you as judged by the absence of voltage fluctuations that can result in flickering/dimming of lights / an affect on



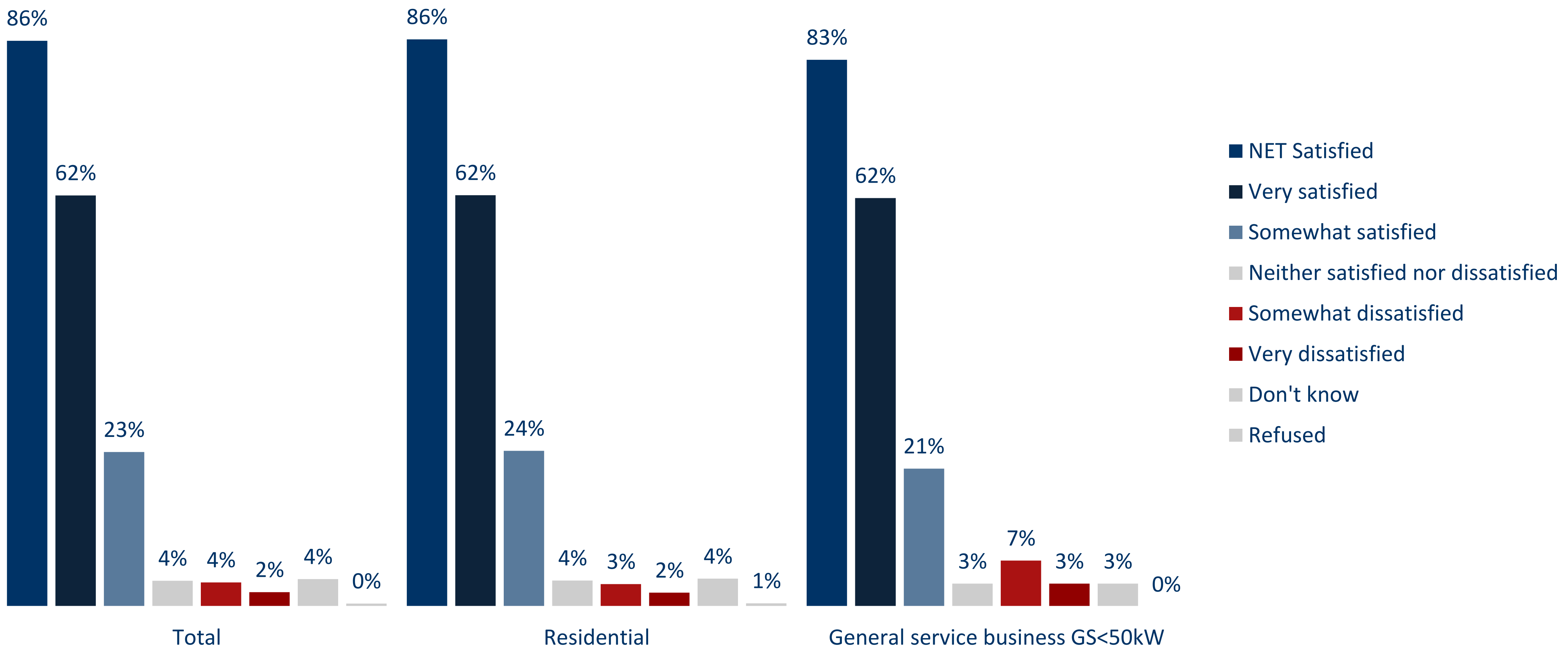
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

How satisfied are you with the bills that you receive from Orangeville Hydro - based on them providing ACCURATE BILLS?



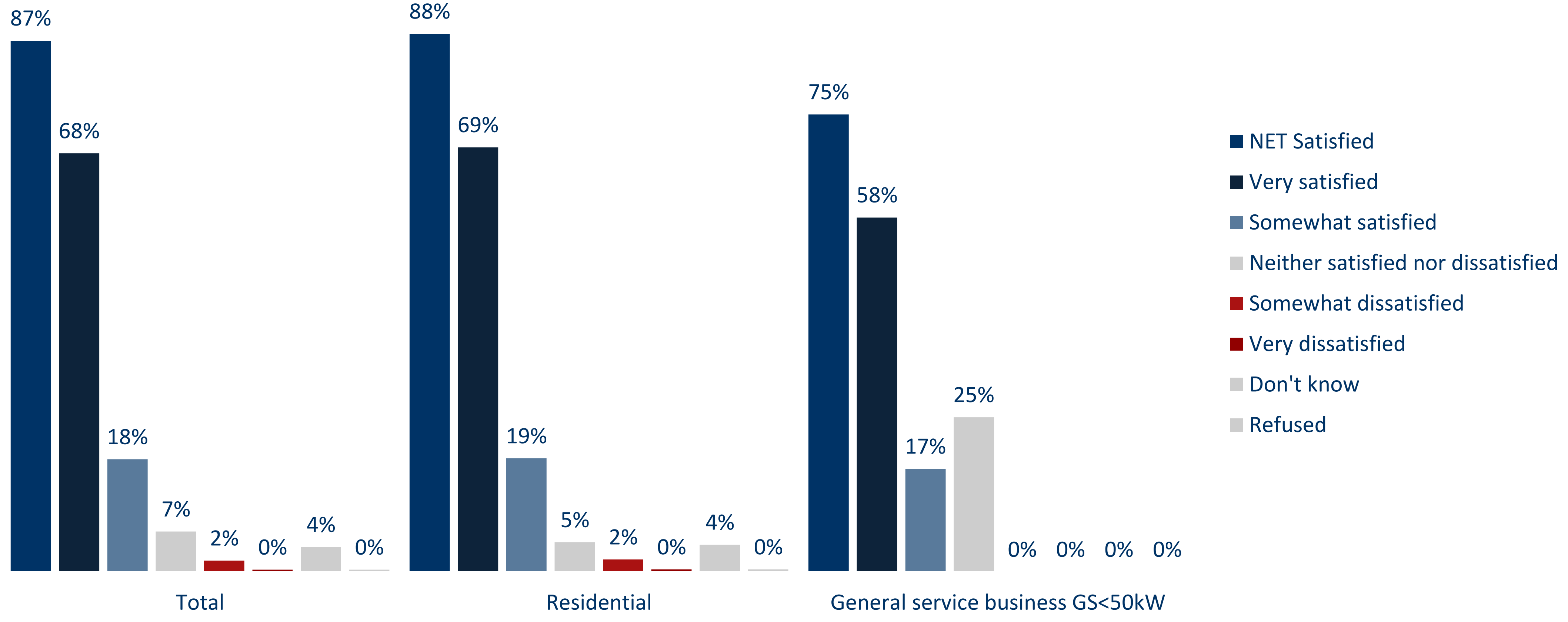
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

How satisfied are you with the bills that you receive from Orangeville Hydro - based on them providing CONVENIENT OPTIONS TO RECEIVE AND PAY BILLS?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

How satisfied are you with the CUSTOMER SERVICE you have received when dealing with employees of Orangeville Hydro, whether on the telephone, via email, in person or through online conversations including social media?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro
Note: Base excludes those who indicated that they had not contacted customer service, thus could not provide an assessment

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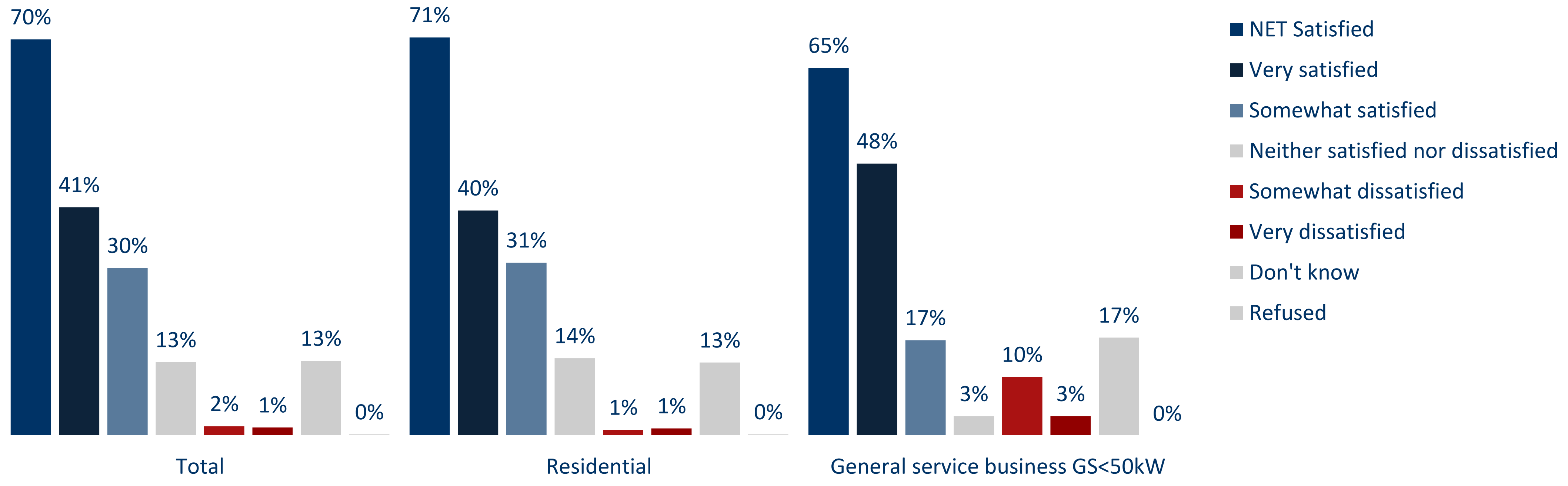
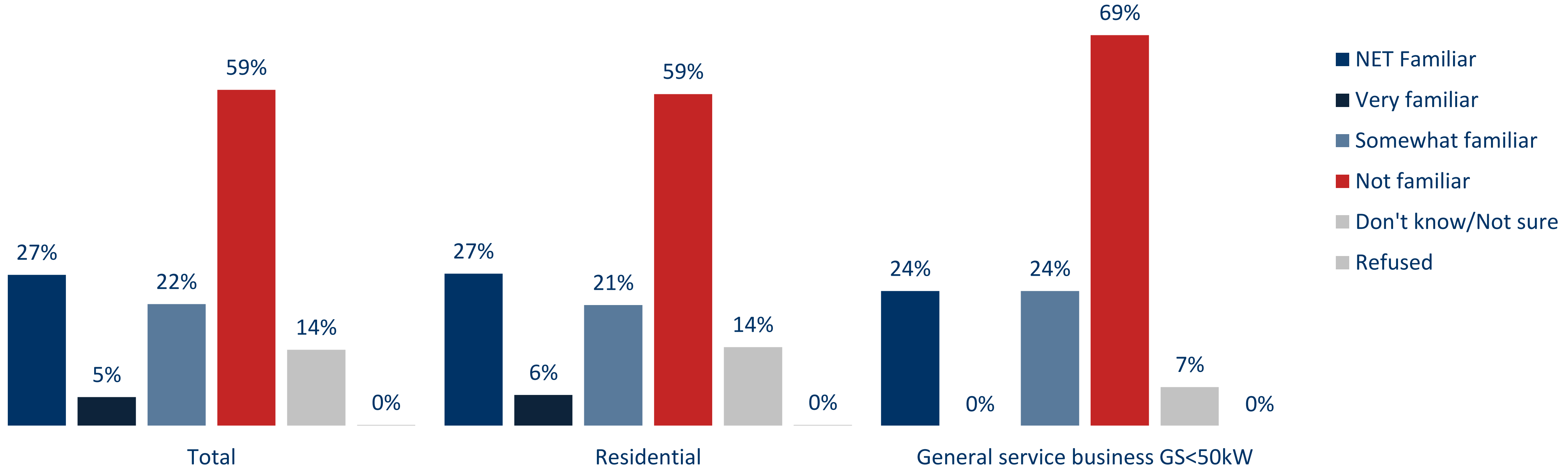
How satisfied are you with the COMMUNICATIONS that you may receive from Orangeville Hydro without talking directly to an employee, including information found on their website, bill inserts, advertising, notices, emails, or social media sites?



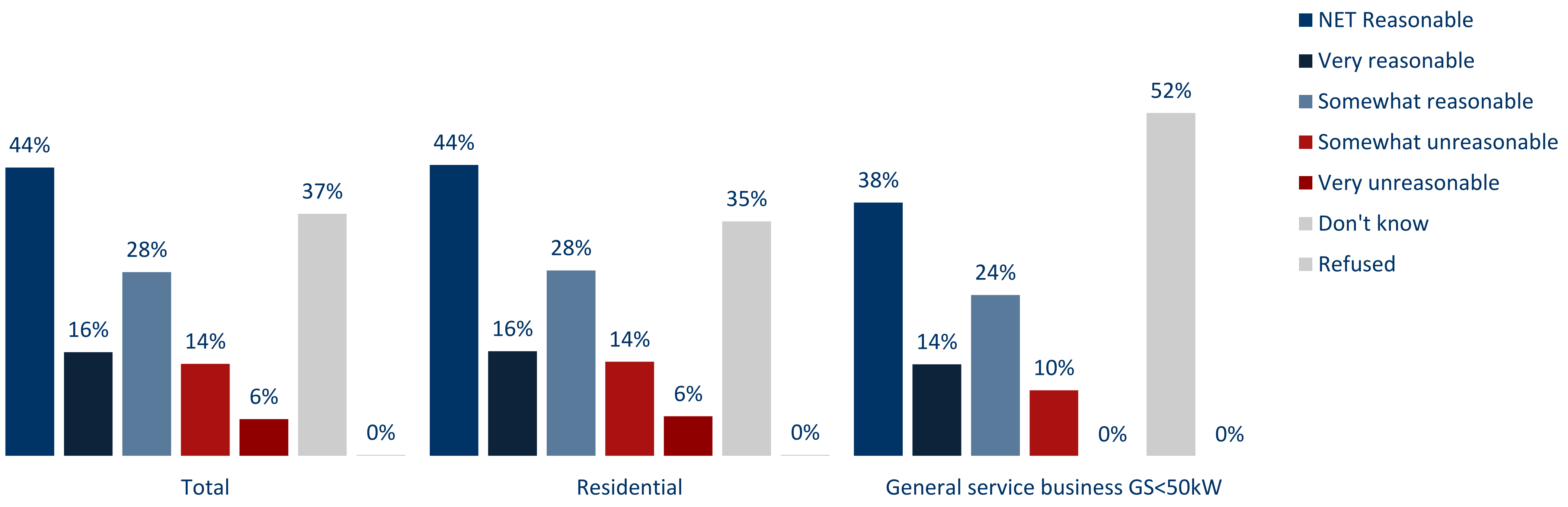
Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

How familiar are you with the percentage of your electricity bill that went to Orangeville Hydro? So, NOT the portions allocated to power generation companies, transmission companies, the provincial government and regulatory agencies.



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

Do you feel that the percentage of your total electricity bill that you pay to Orangeville Hydro for the services they provide is...?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

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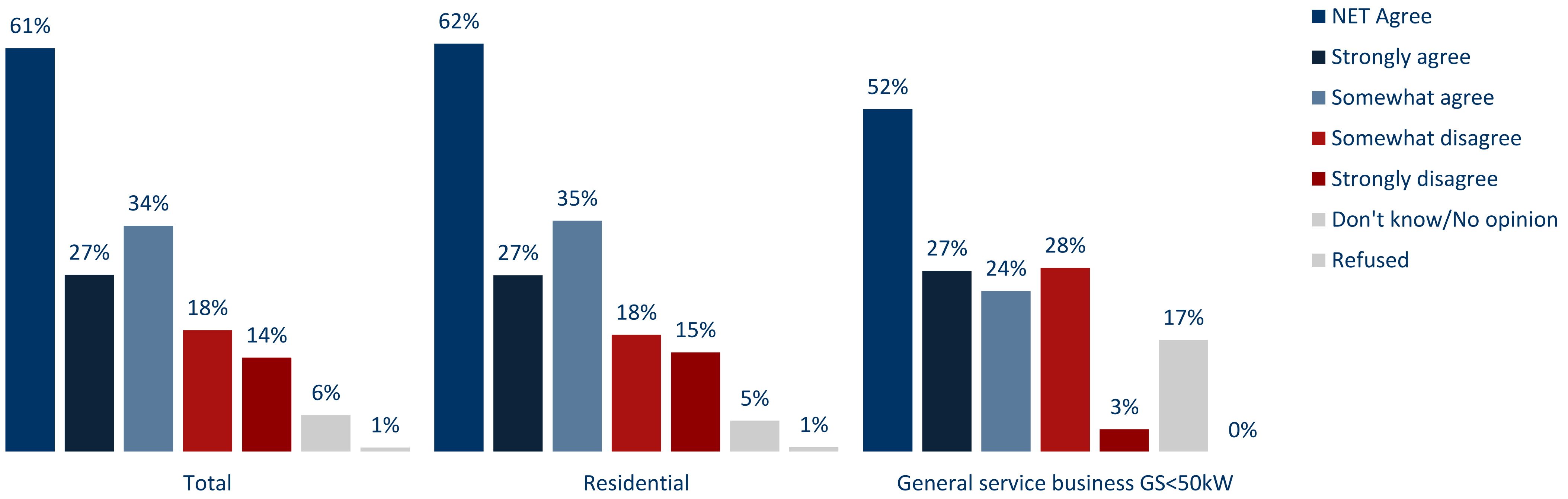
To what extent do you agree with "The cost of my electricity bill has a major impact [on personal finances OR bottom line of organization]"?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

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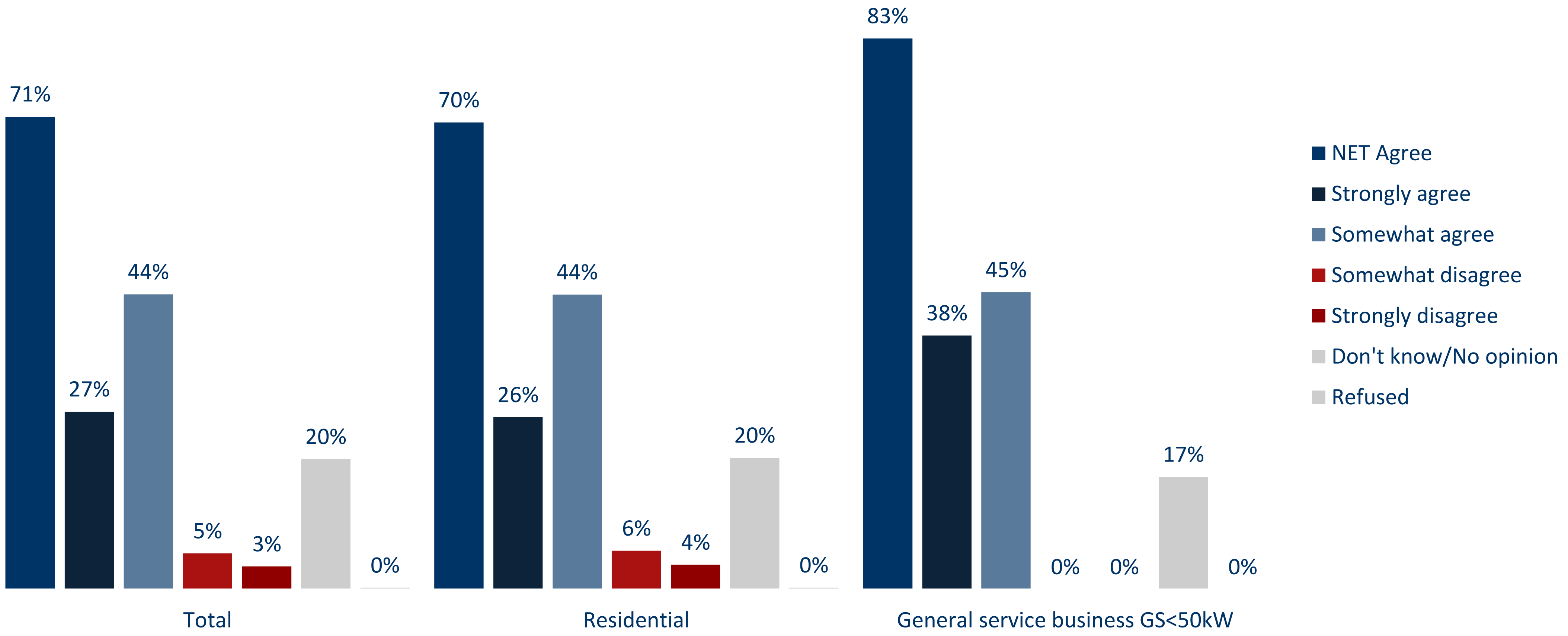
To what extent do you agree with "Customers are well served by the electricity system in Ontario"?



Weight: Aggregate weight for LDC based on customer_type
Filters: Year of Data Collection: 2023, LDC: Orangeville Hydro

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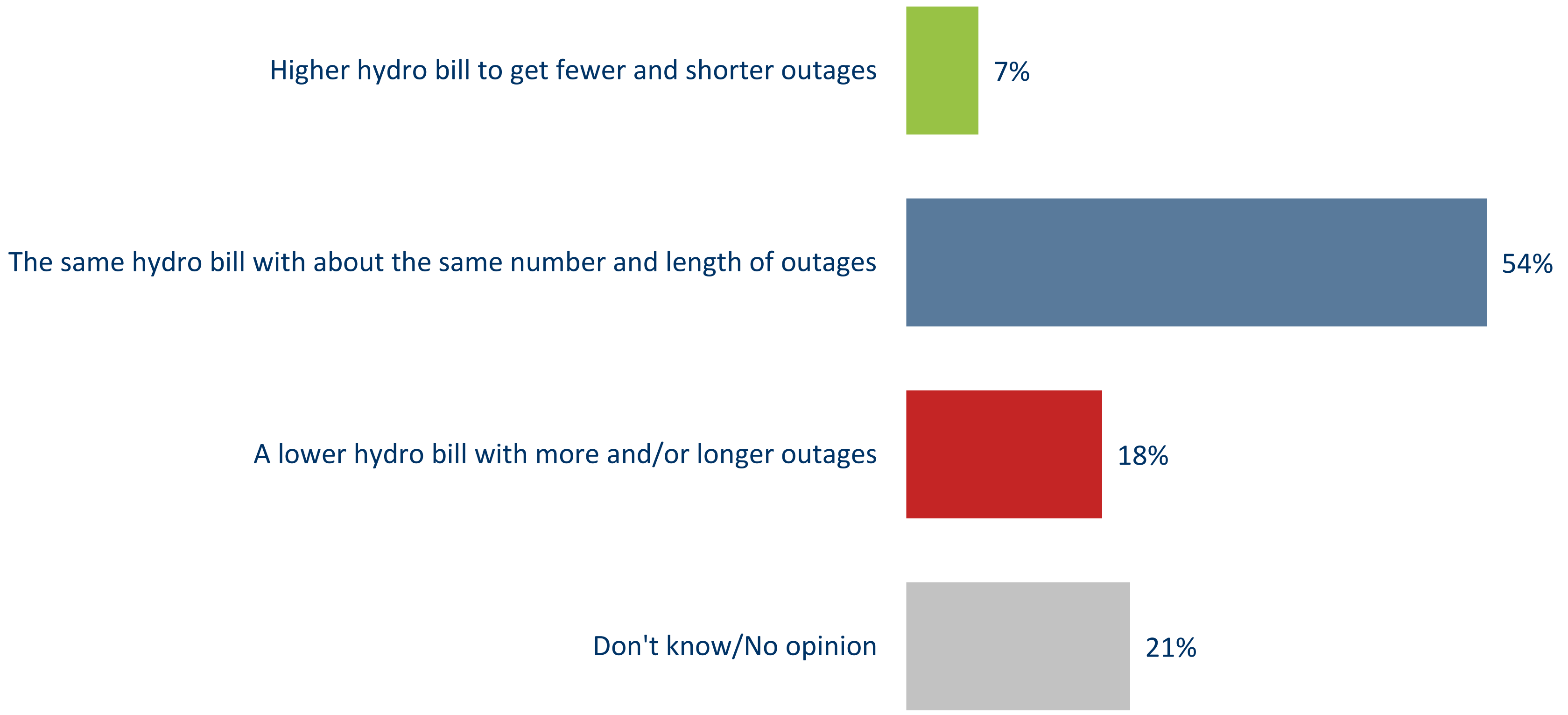
Orangeville Hydro’s Custom Survey Questions – 2023 Results

Orangeville Hydro has significant amounts of infrastructure such as poles, wires and transformers which are used to deliver power and maintain system reliability. How supportive are you of future infrastructure investments, recognizing it may mean an incr



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Filters: LDC: Orangeville Hydro, Year of Data Collection: 2023
Base Size: 383

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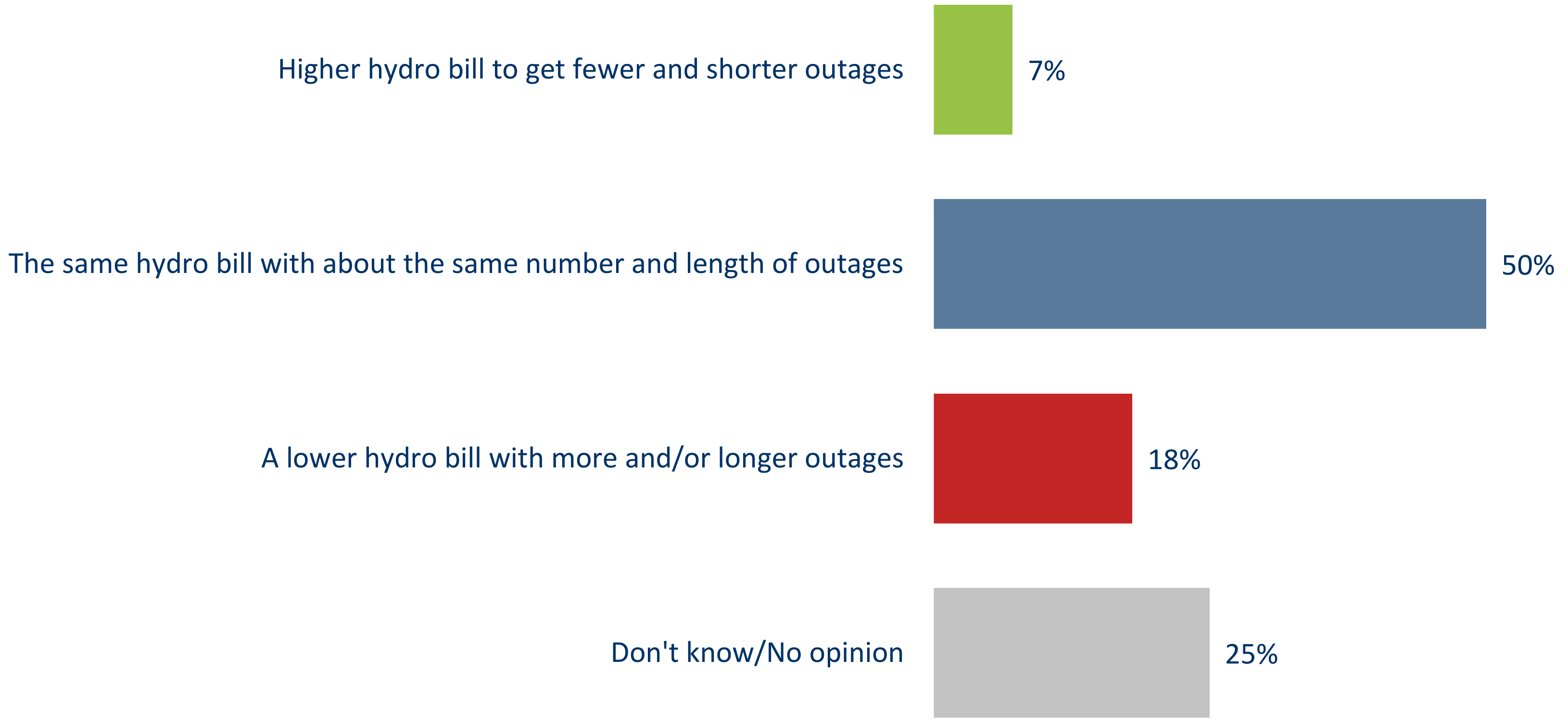
Orangeville Hydro uses vehicles, equipment, computer and IT systems to service the distribution system and manage customer information. How supportive are you of future equipment investments, recognizing it may mean an increase to your monthly bill?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro, Year of Data Collection: 2023
Base Size: 389

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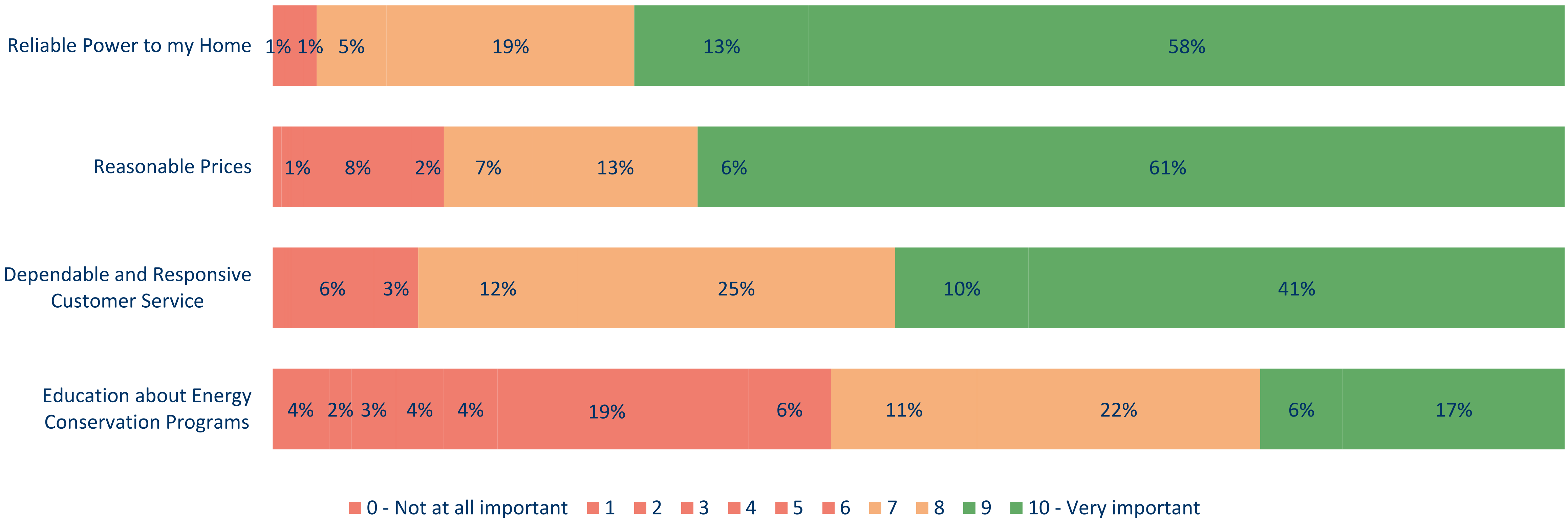
Please rate the importance of the following priorities from 0 (not important at all) to 10 (meaning very important).



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro, Year of Data Collection: 2023
Base Size: 407

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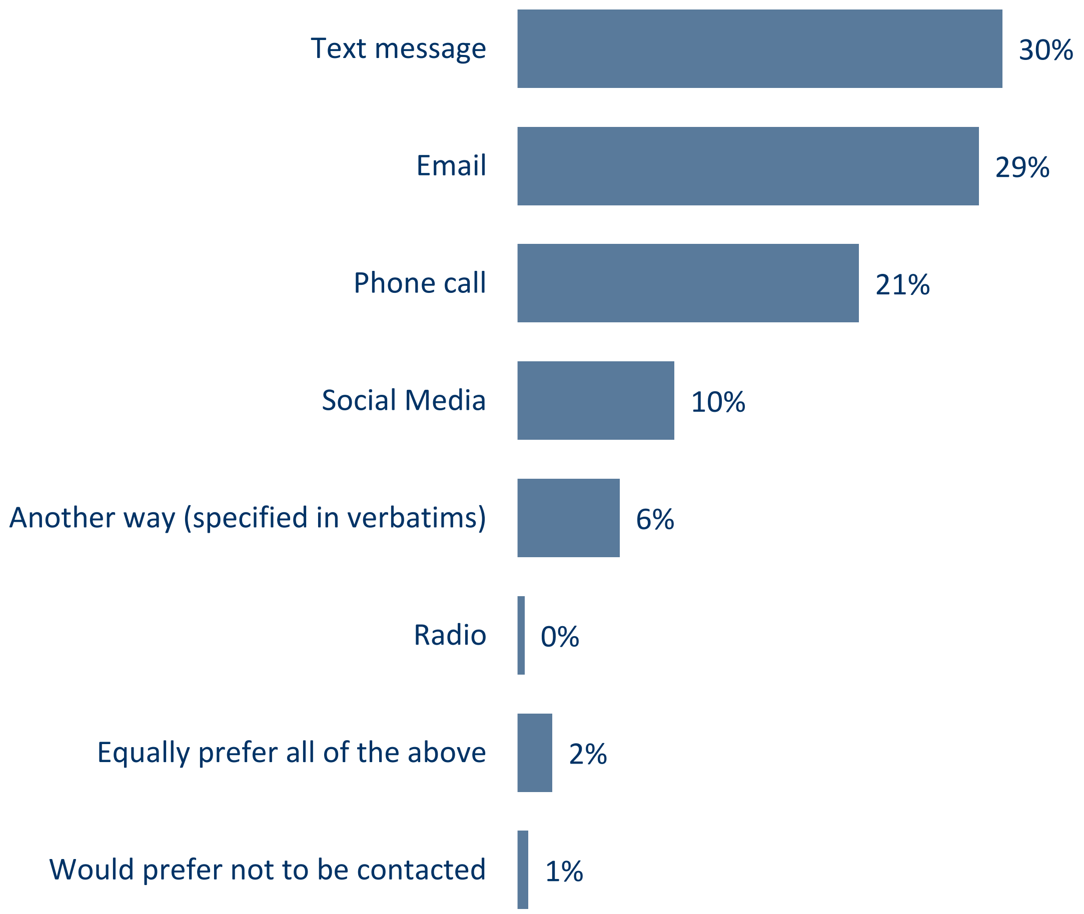
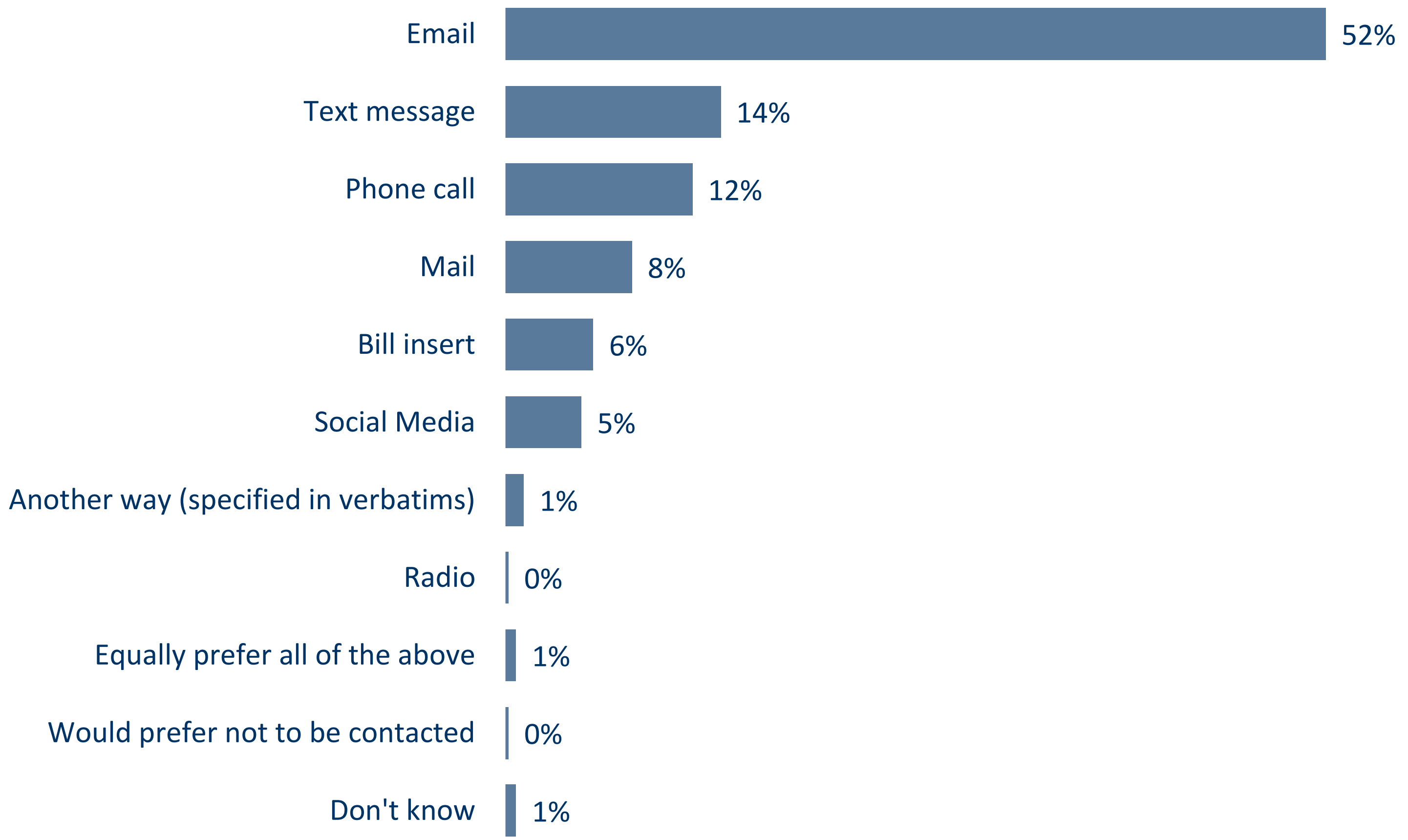
How would you most prefer to be alerted by Orangeville Hydro for URGENT INFORMATION items, such as unplanned service interruptions?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro, Year of Data Collection: 2023
Base Size: 407

How would you most prefer to be alerted by Orangeville Hydro for REGULAR CUSTOMER INFORMATION items, such as planned outages, system upgrades, etc.?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro, Year of Data Collection: 2023
Base Size: 407

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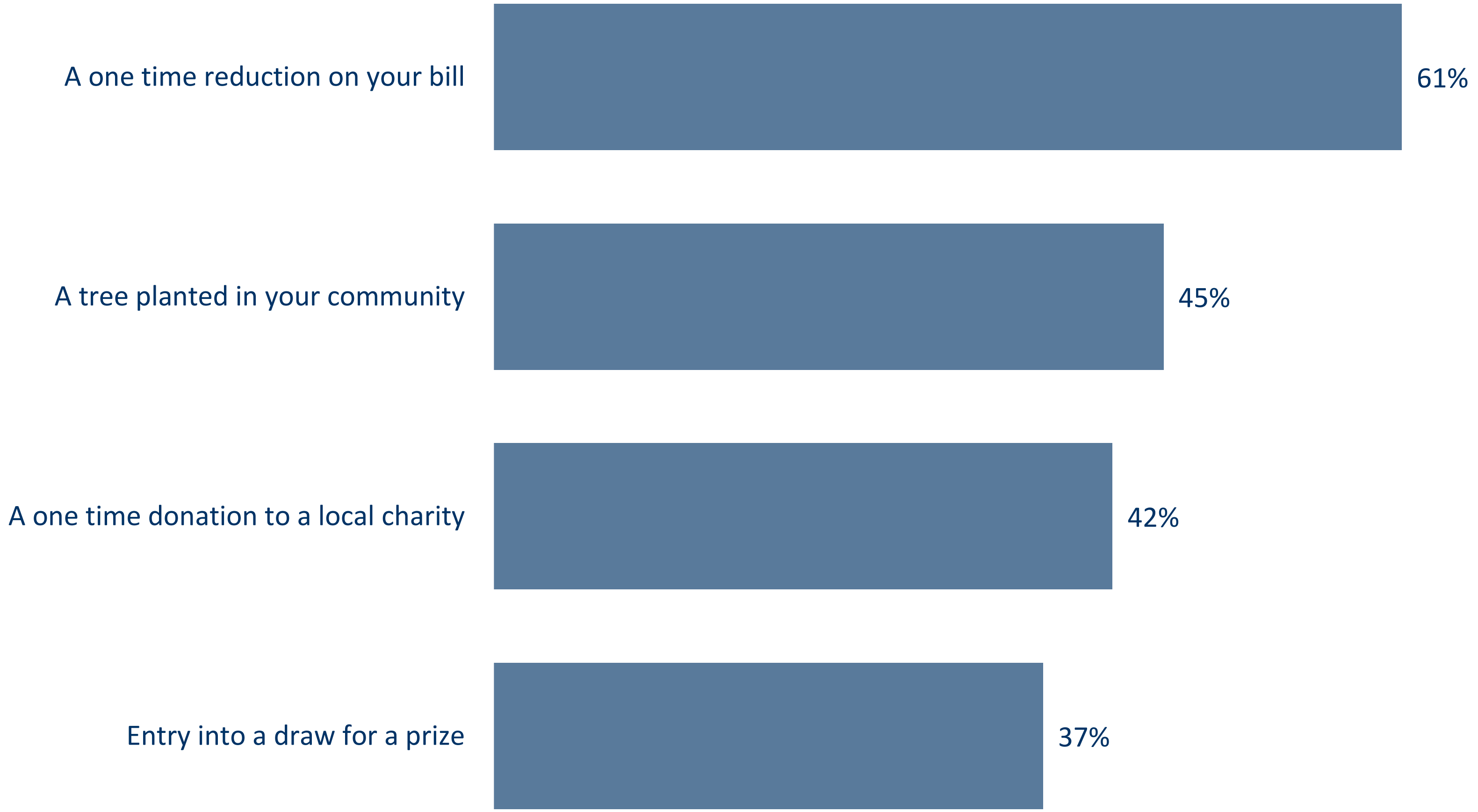
% Selected 'Yes': For each of the following offers, would they encourage you to SWITCH your monthly electric bill from regular TO EMAIL (electronic mail)?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro, Year of Data Collection: 2023
Base Size: 407

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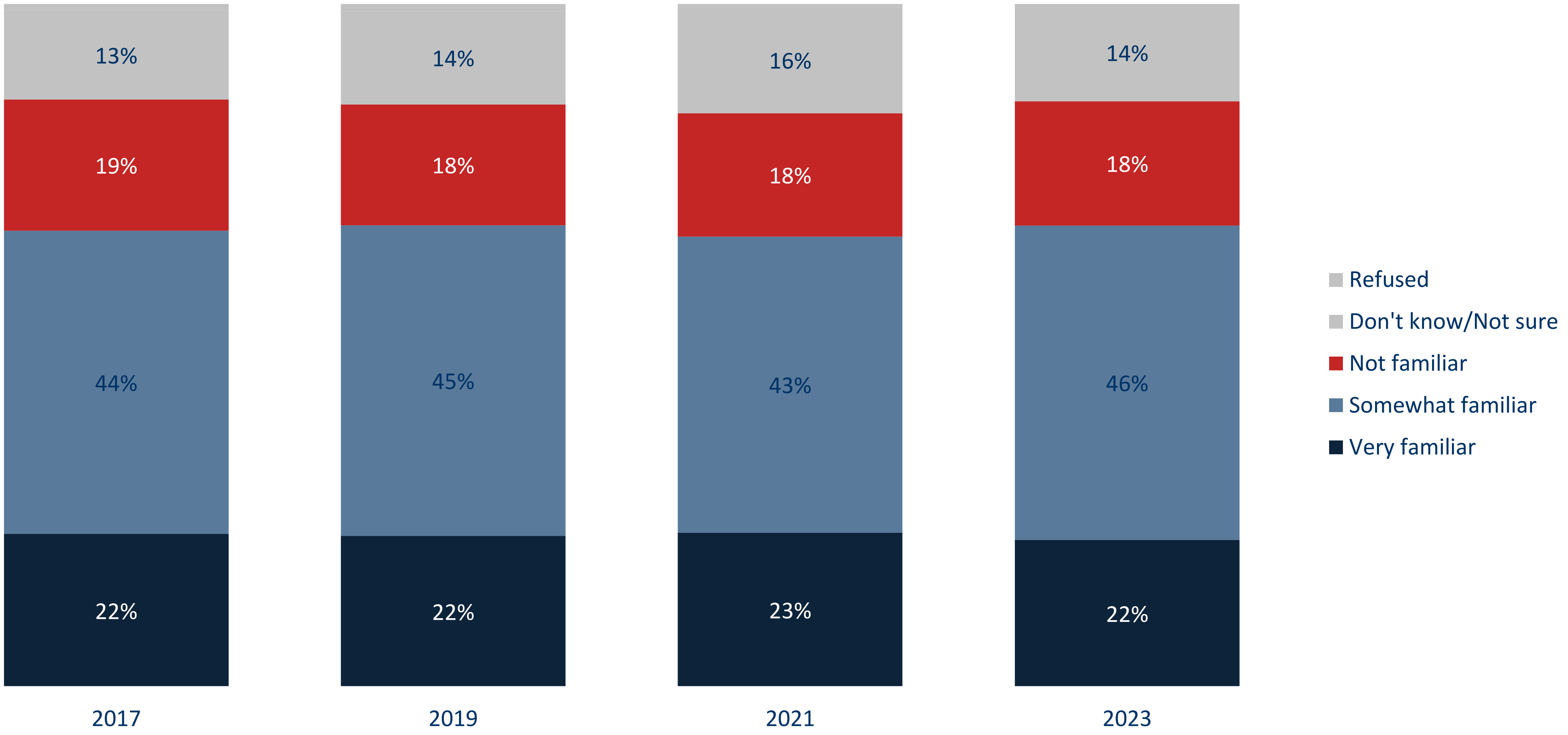
Core (OEB) Survey Questions – Trend over Time

How familiar are you with Orangeville Hydro, which operates the electricity distribution system in your community?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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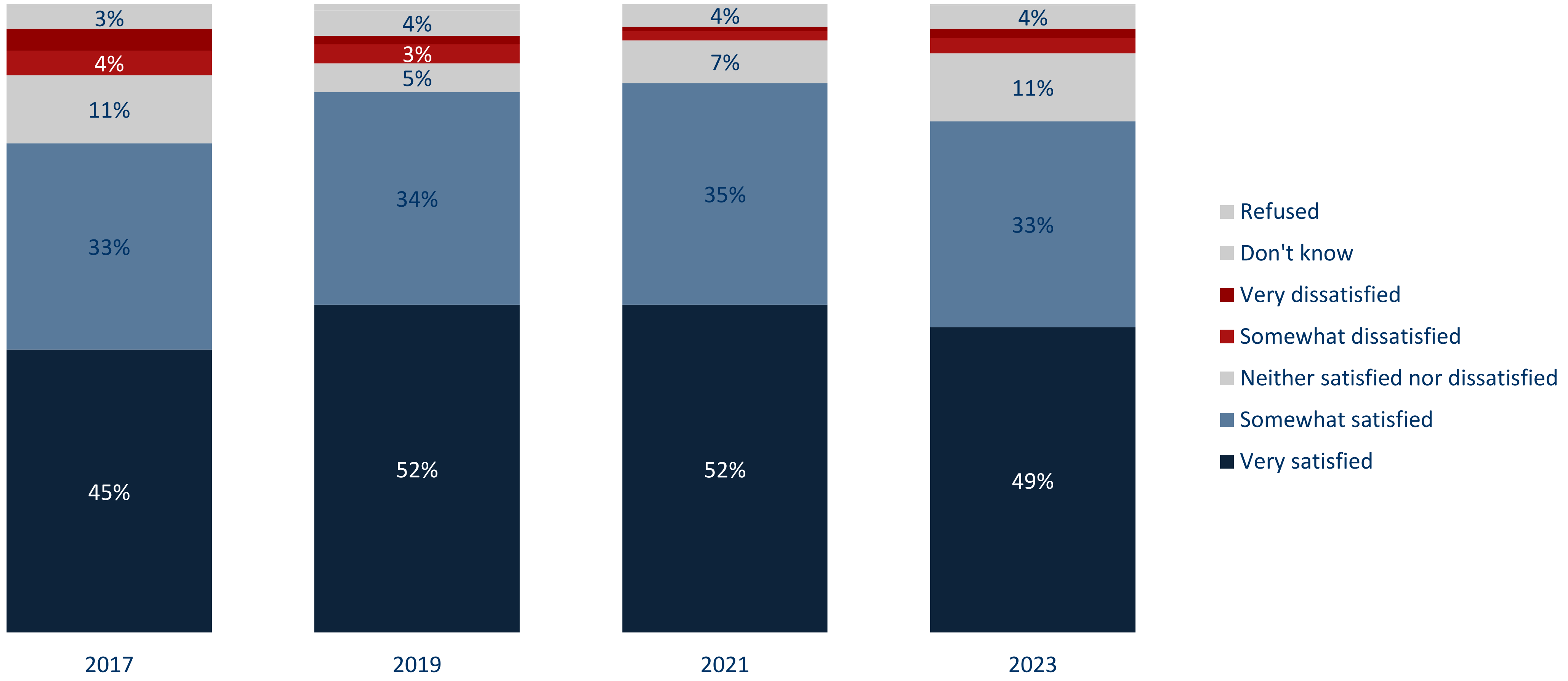
Thinking specifically about the services provided to you and your community by Orangeville Hydro, OVERALL, how satisfied are you with the services that you receive?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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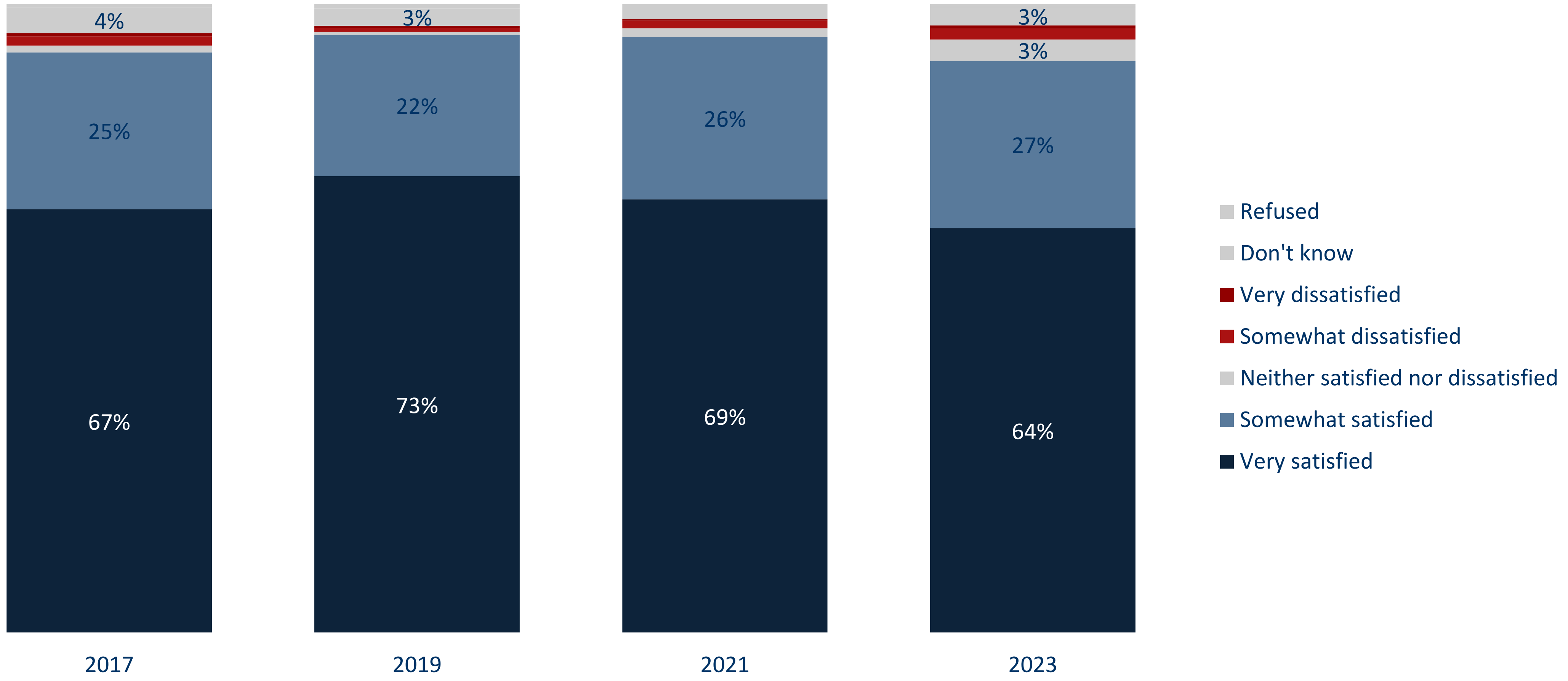
How satisfied are you with the electrical service that you receive from Orangeville Hydro - based on the RELIABILITY of your electrical service as judged by the number of outages you experience?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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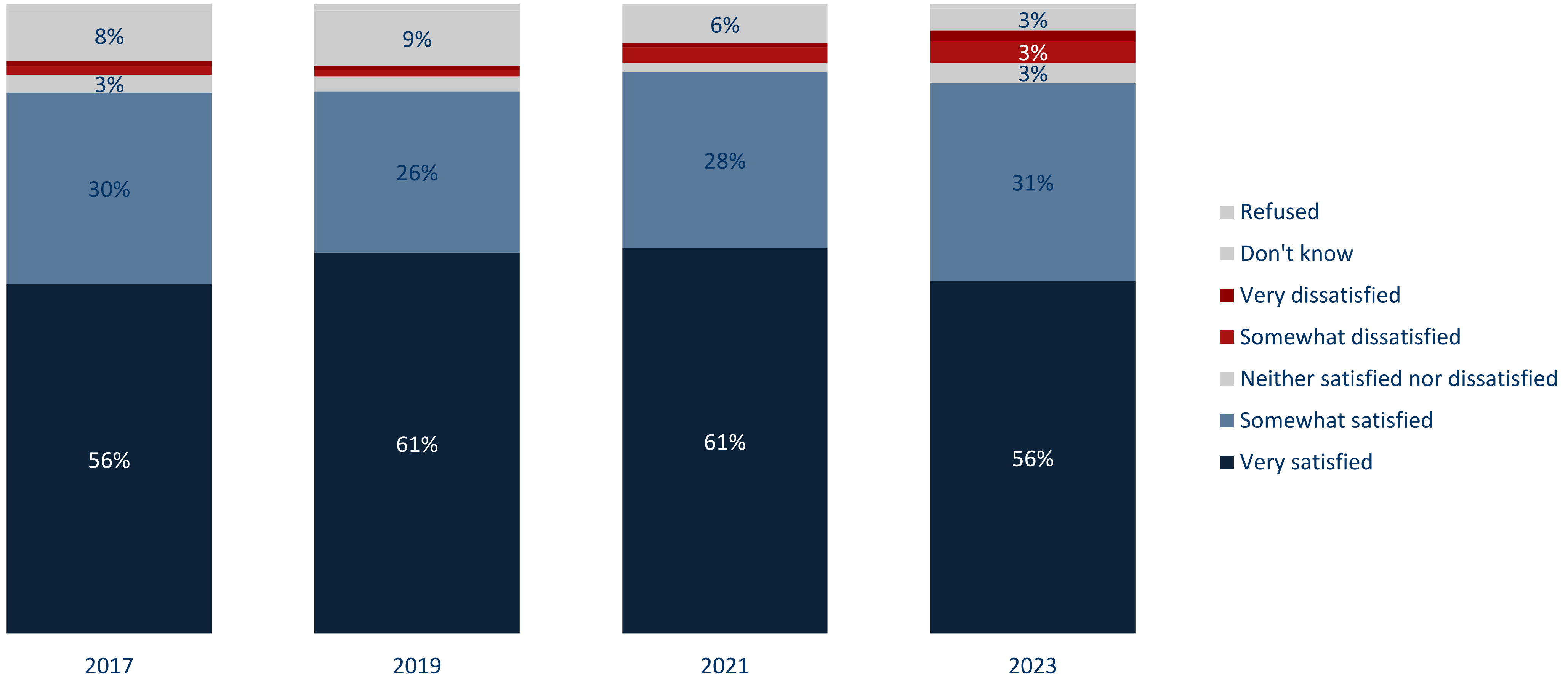
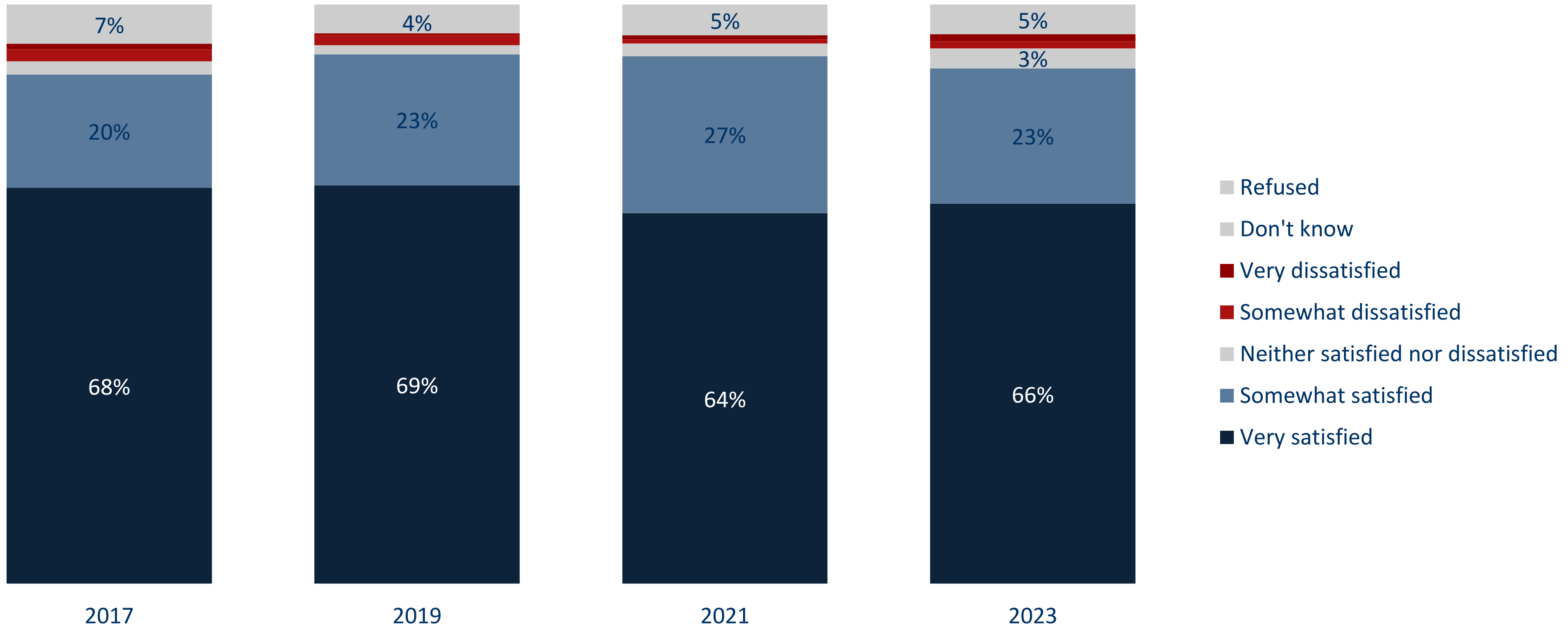
How satisfied are you with the electrical service that you receive from Orangeville Hydro - based on the amount of TIME IT TAKES TO RESTORE POWER when outages occur?



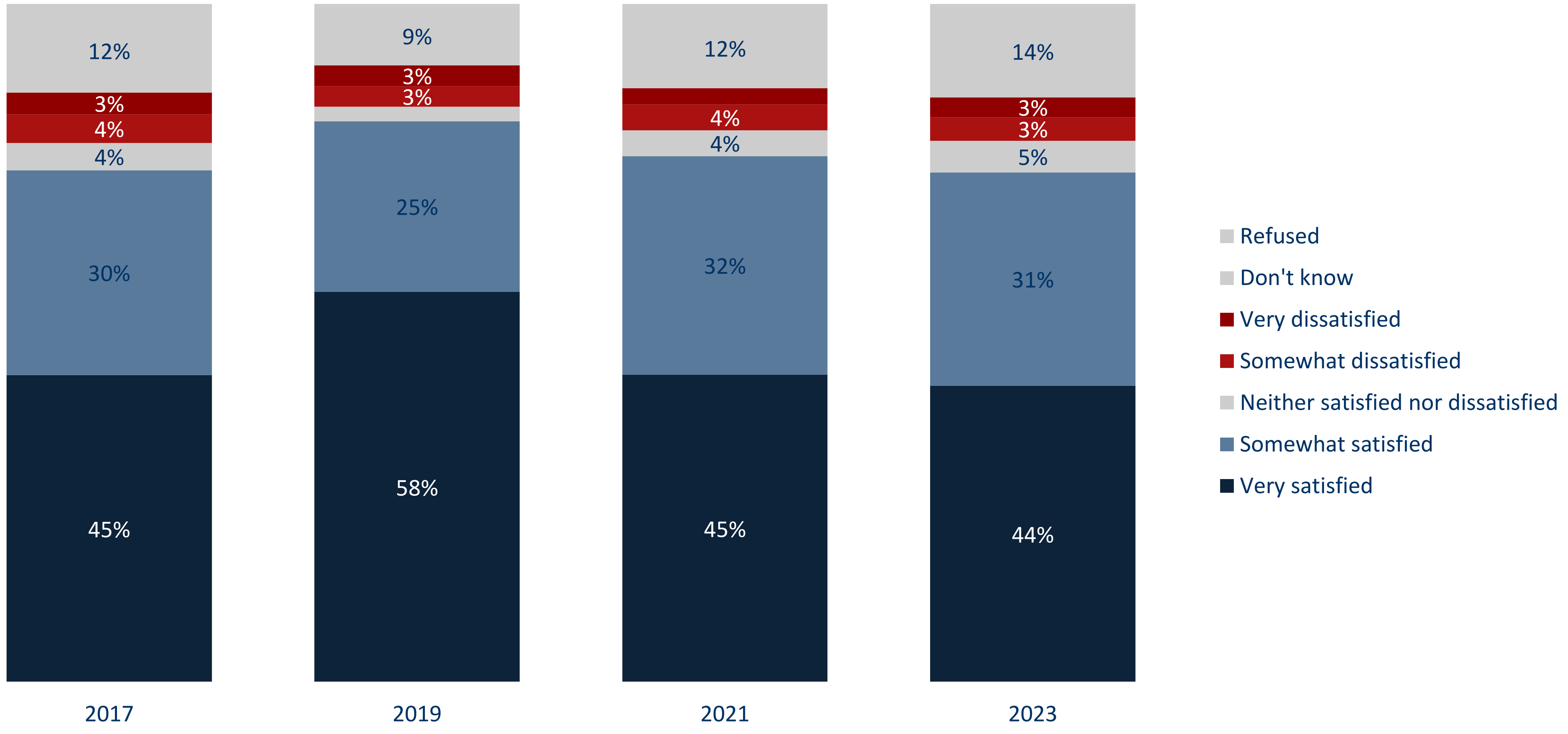
Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

How satisfied are you with the electrical service that you receive from Orangeville Hydro - based on the QUALITY OF THE POWER delivered to you as judged by the absence of voltage fluctuations that can result in flickering/dimming of lights / an affect on



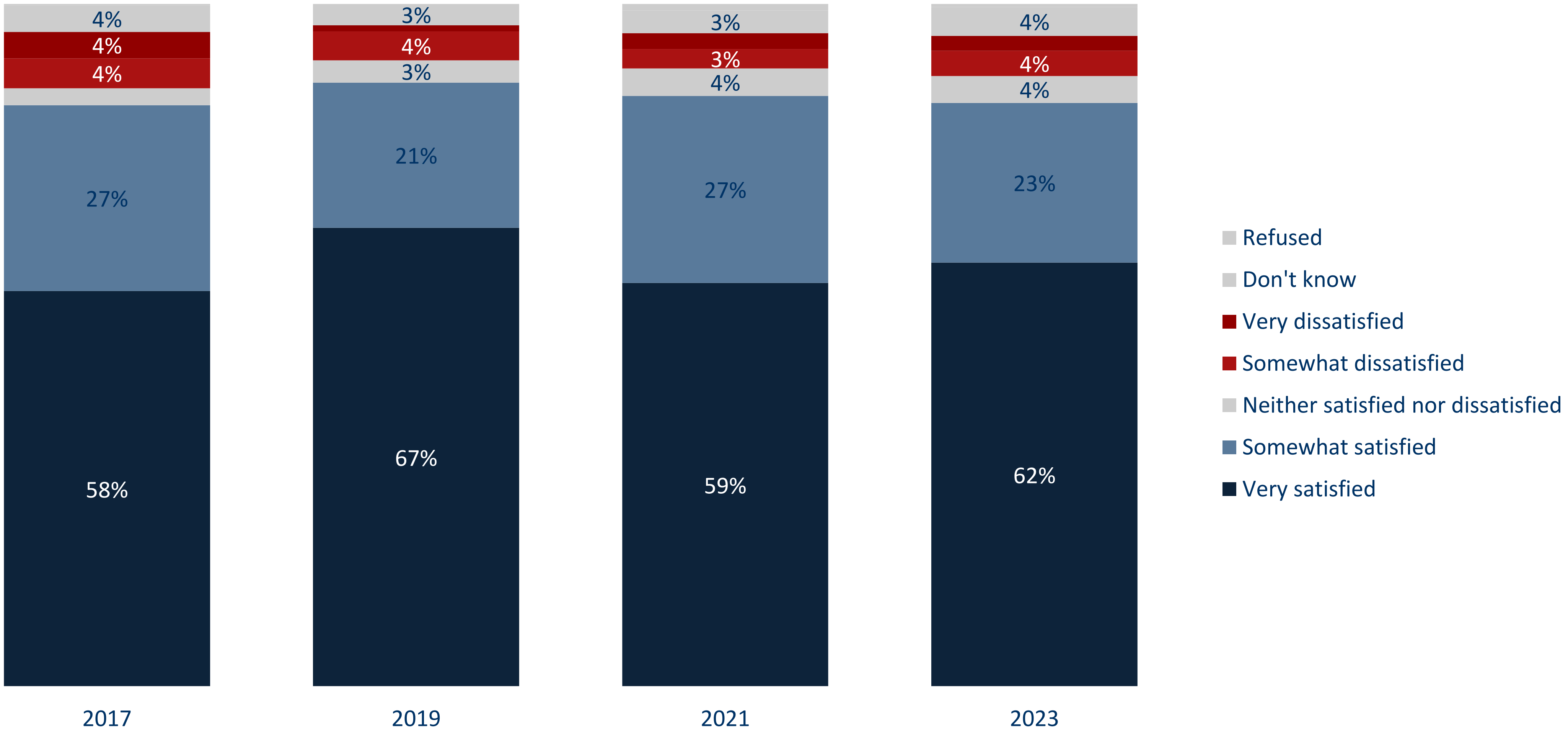
Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

How satisfied are you with the bills that you receive from Orangeville Hydro - based on them providing ACCURATE BILLS?



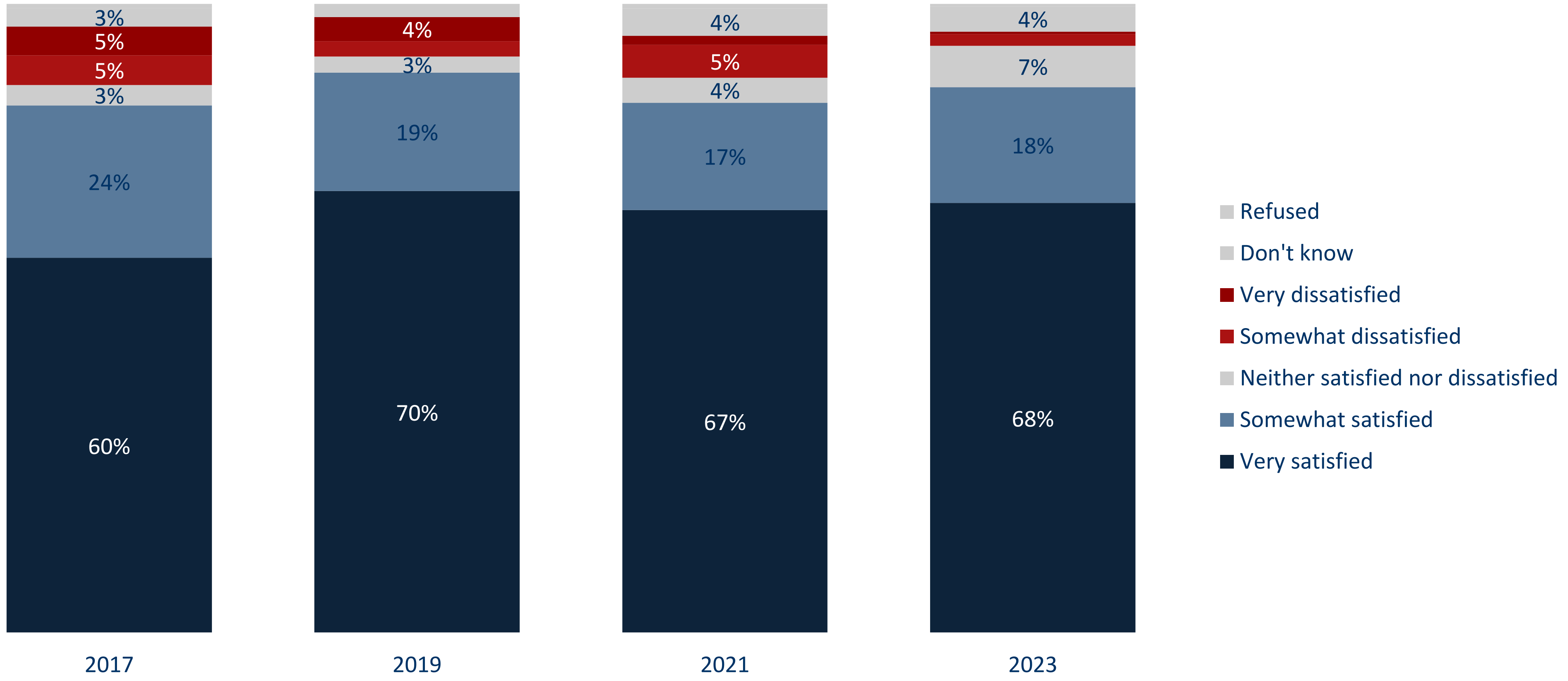
Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

How satisfied are you with the bills that you receive from Orangeville Hydro - based on them providing CONVENIENT OPTIONS TO RECEIVE AND PAY BILLS?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

How satisfied are you with the CUSTOMER SERVICE you have received when dealing with employees of Orangeville Hydro, whether on the telephone, via email, in person or through online conversations including social media?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro
Note: Base excludes those who indicated that they had not contacted customer service, thus could not provide an assessment

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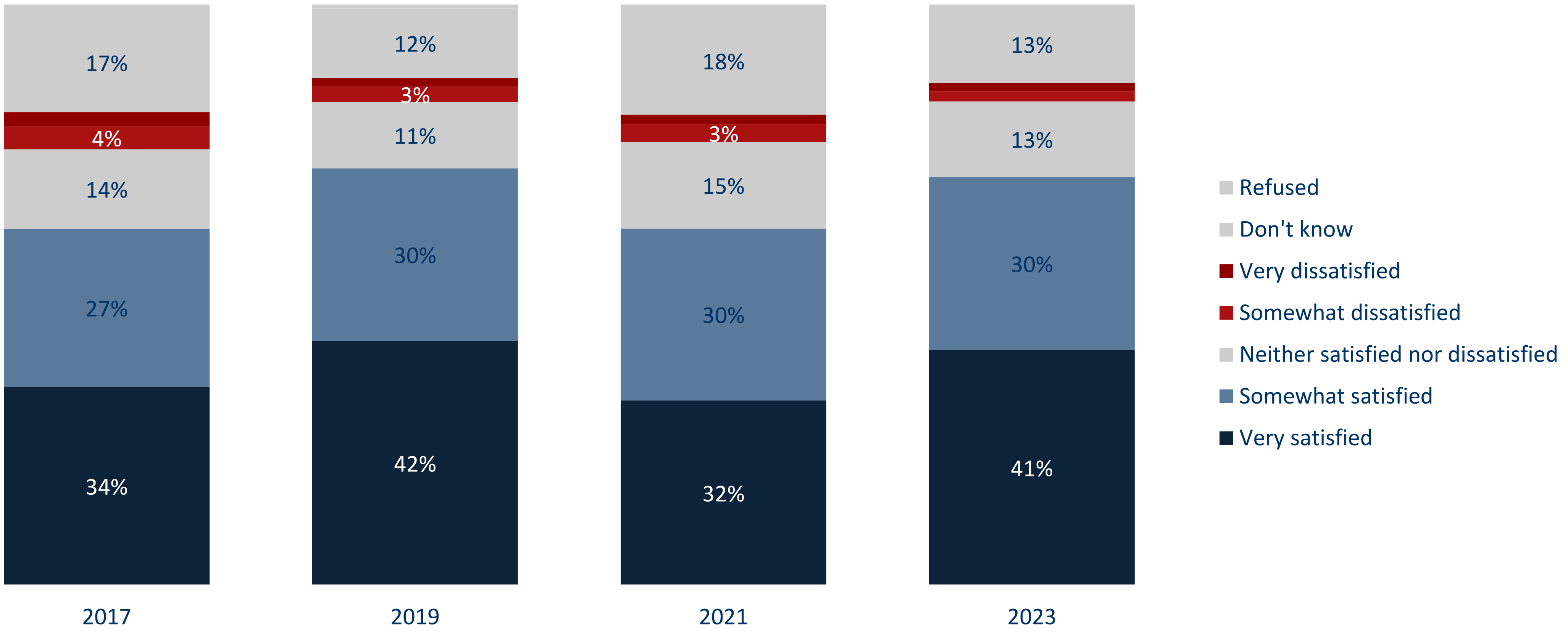
How satisfied are you with the COMMUNICATIONS that you may receive from Orangeville Hydro without talking directly to an employee, including information found on their website, bill inserts, advertising, notices, emails, or social media sites?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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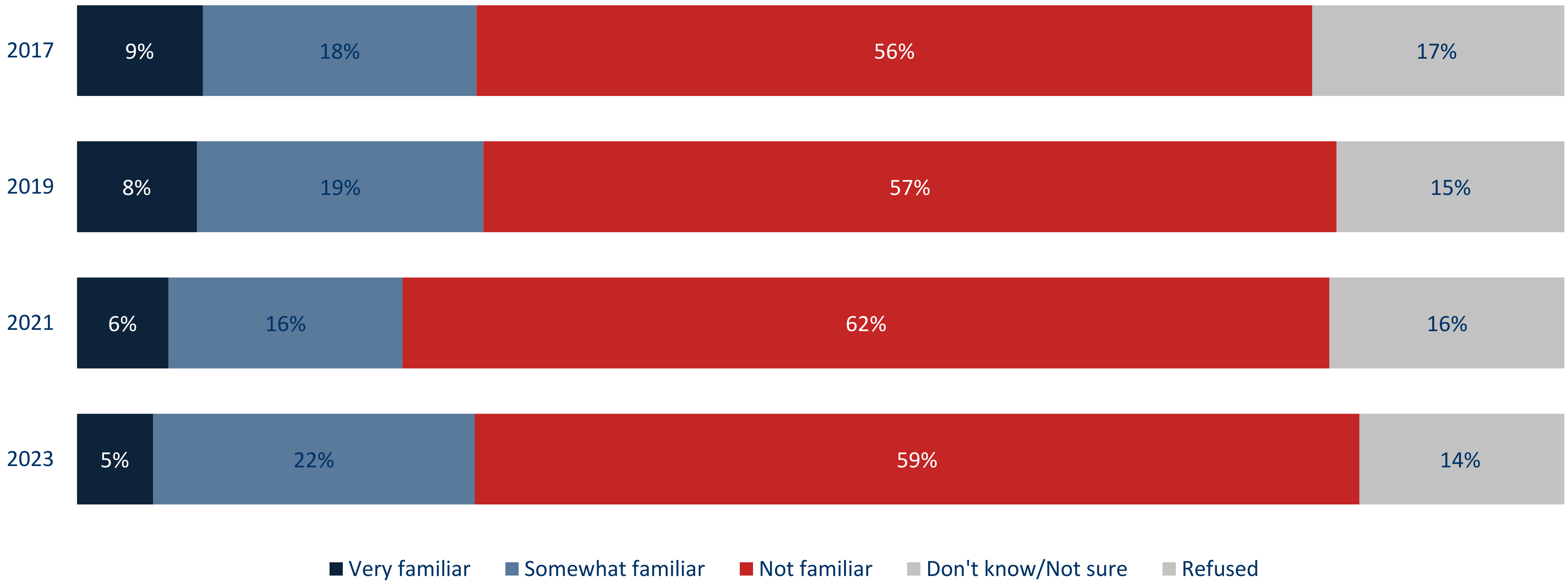
How familiar are you with the percentage of your electricity bill that went to Orangeville Hydro? So, NOT the portions allocated to power generation companies, transmission companies, the provincial government and regulatory agencies.



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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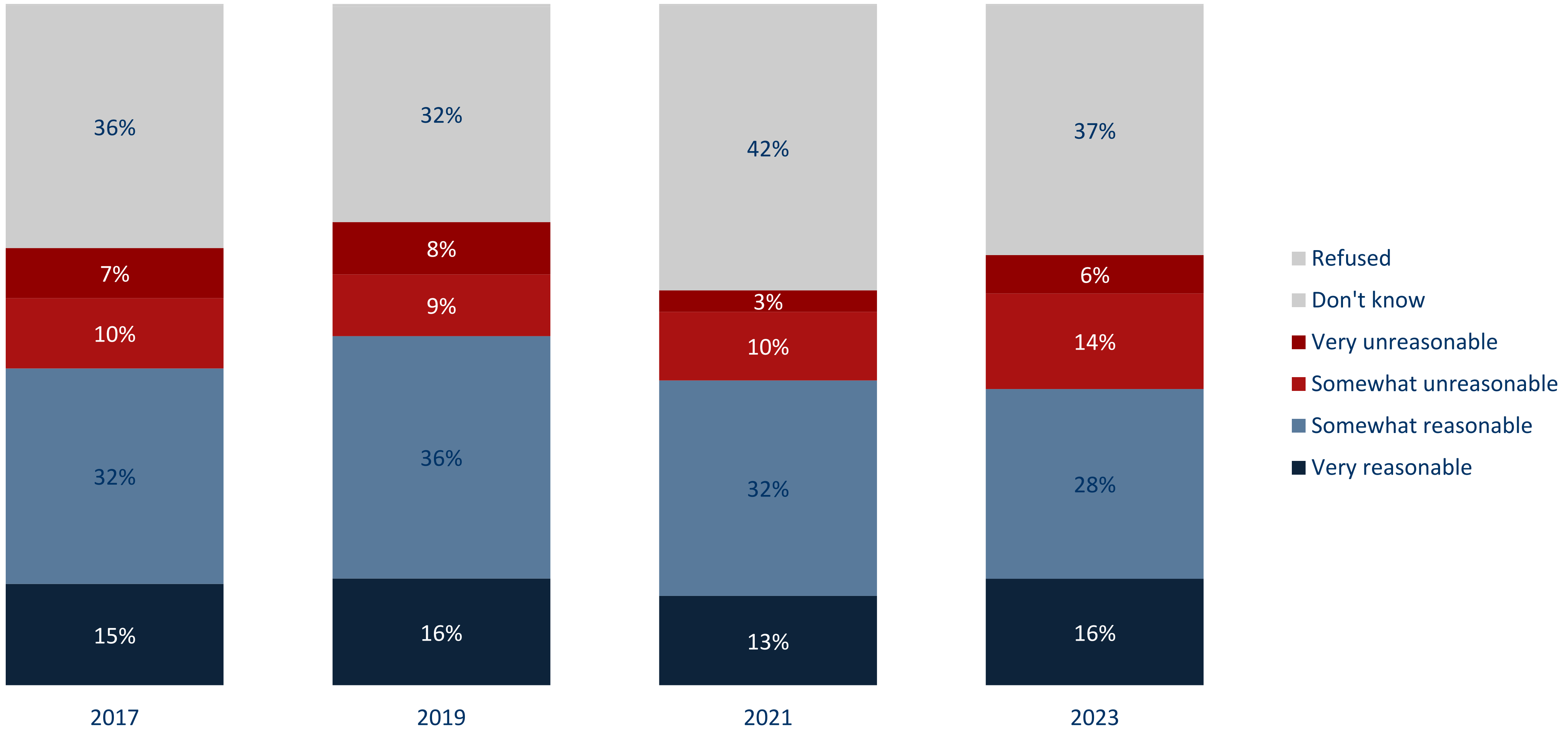
Do you feel that the percentage of your total electricity bill that you pay to Orangeville Hydro for the services they provide is...?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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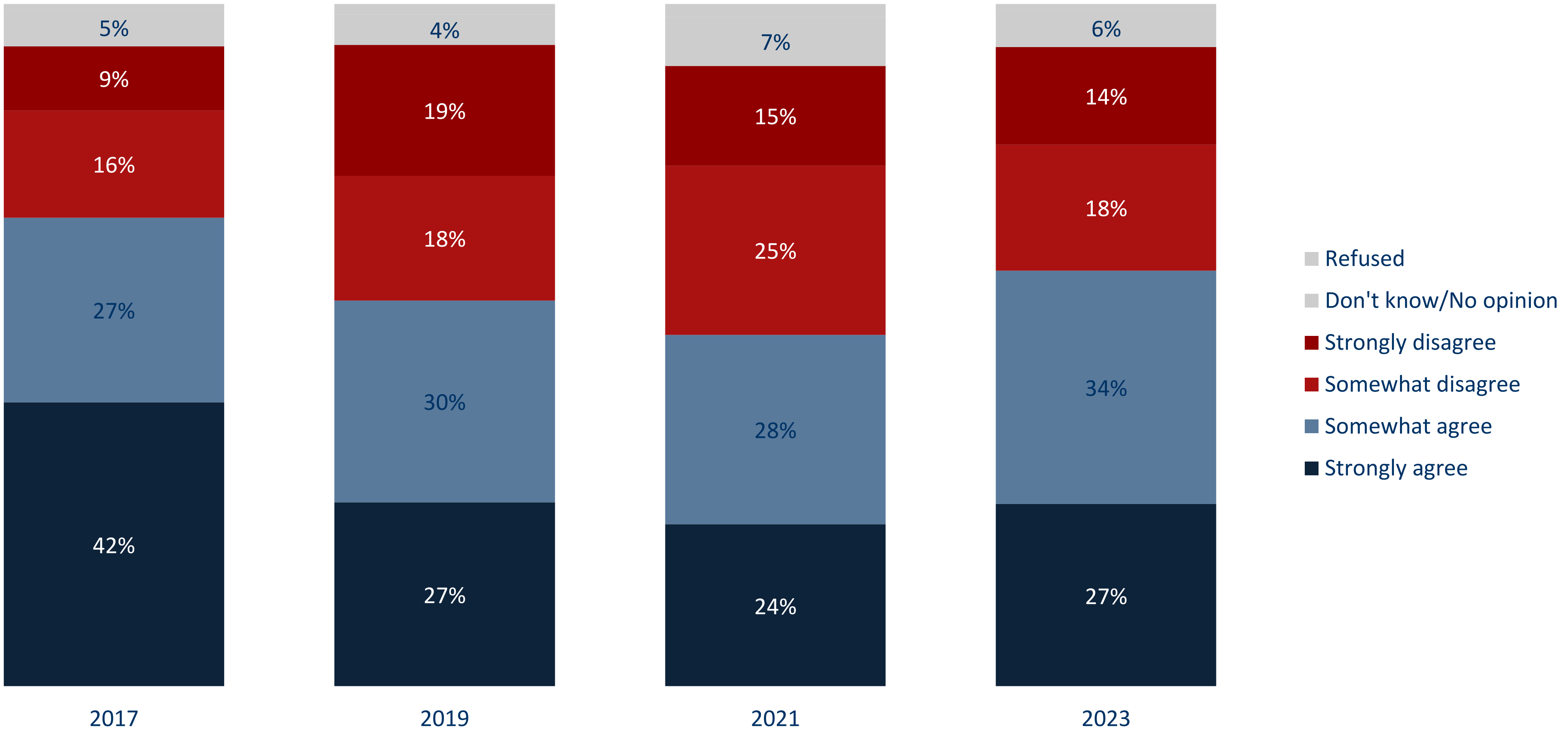
To what extent do you agree with "The cost of my electricity bill has a major impact [on personal finances OR bottom line of organization]"?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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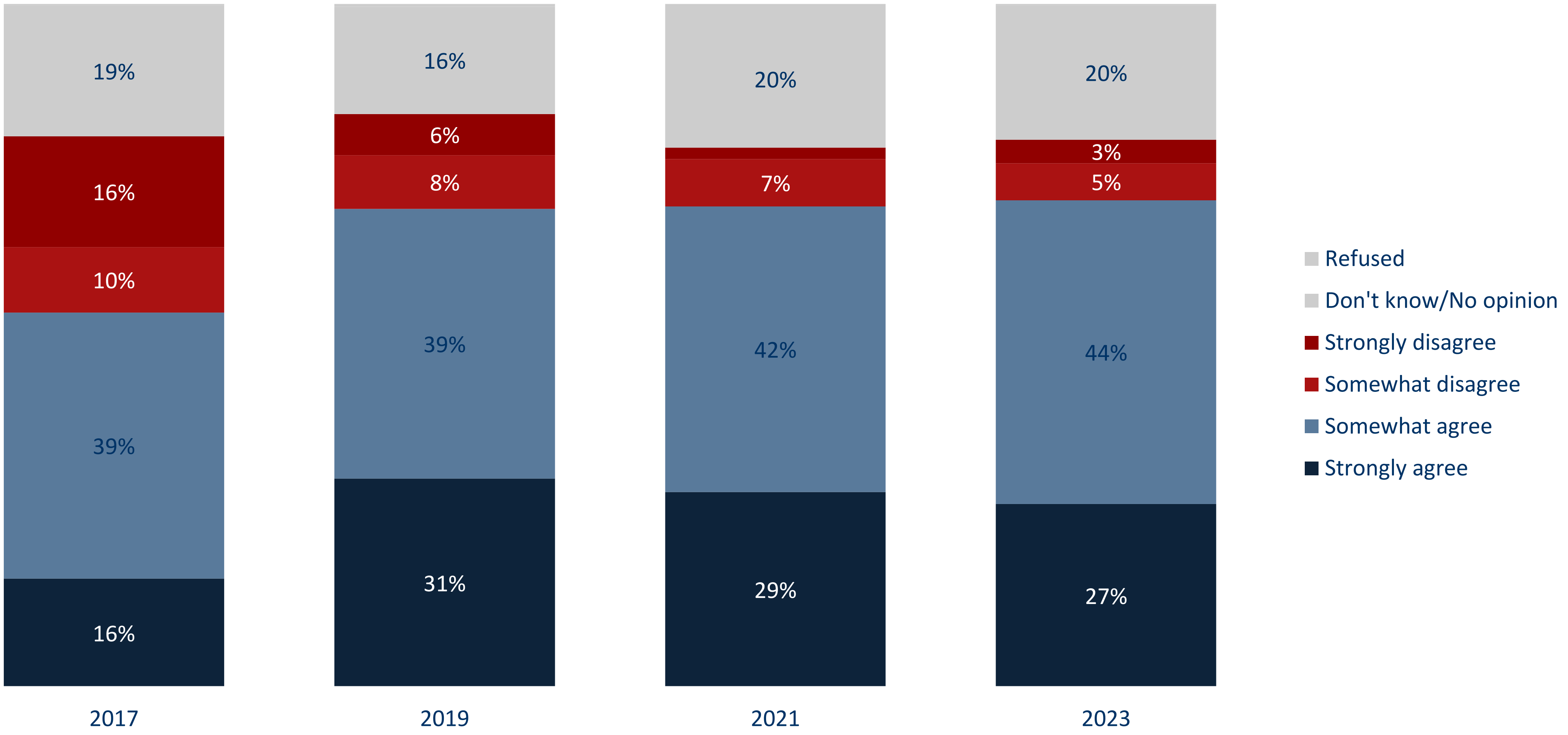
To what extent do you agree with "Customers are well served by the electricity system in Ontario"?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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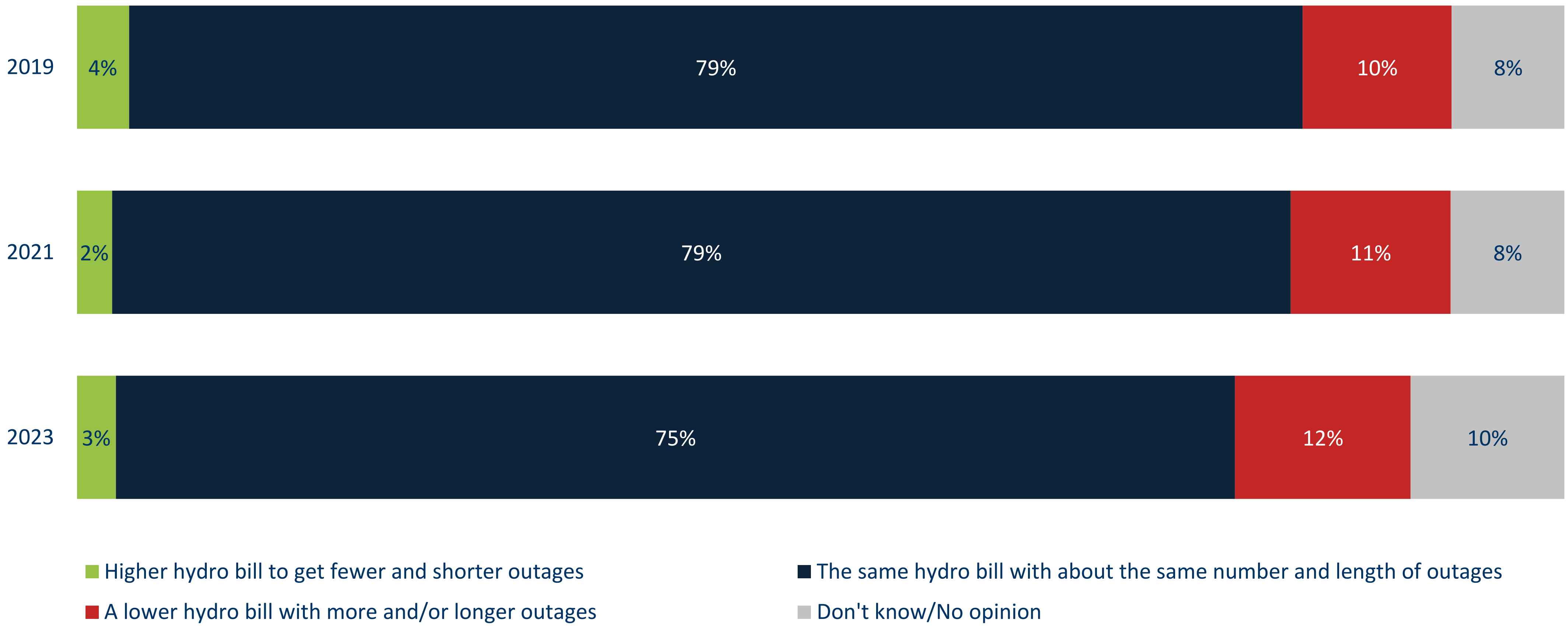
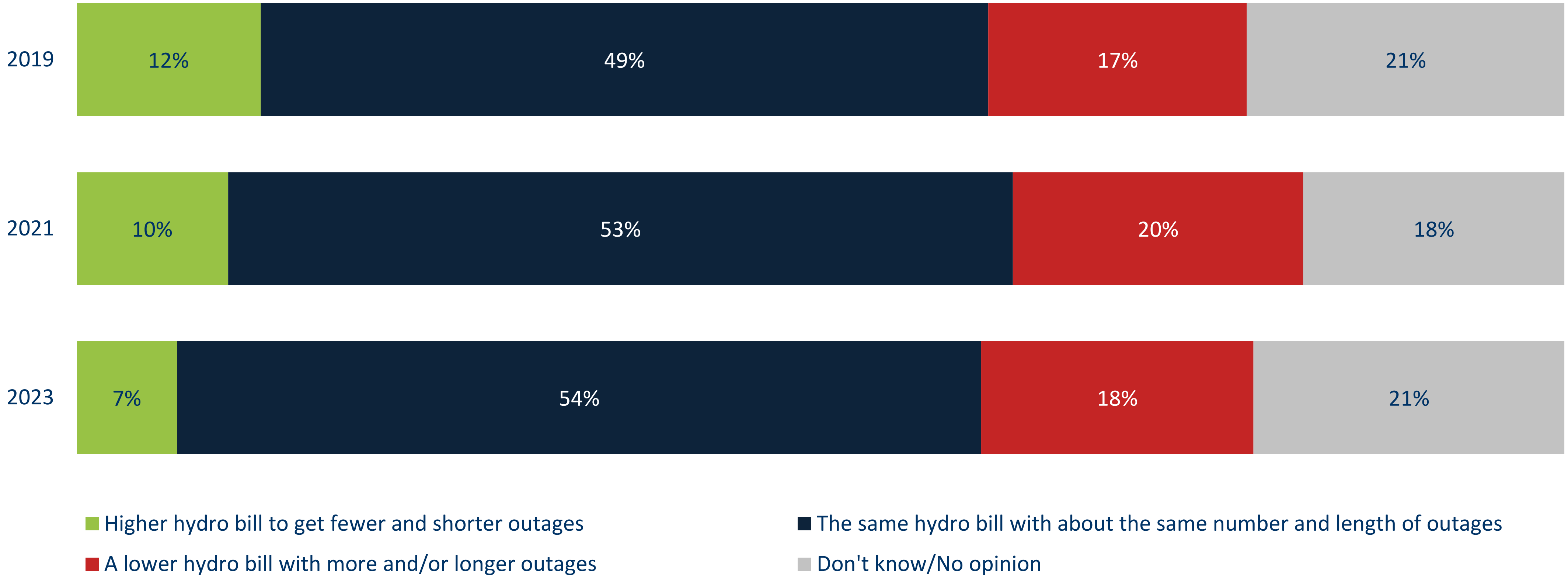
Orangeville Hydro’s Custom Survey Questions– Trend over Time

Orangeville Hydro occasionally has unexpected power outages. To have fewer and shorter outages, it requires more investment by OHL. Which of the following three options do you prefer?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

Orangeville Hydro has significant amounts of infrastructure such as poles, wires and transformers which are used to deliver power and maintain system reliability. How supportive are you of future infrastructure investments, recognizing it may mean an incr



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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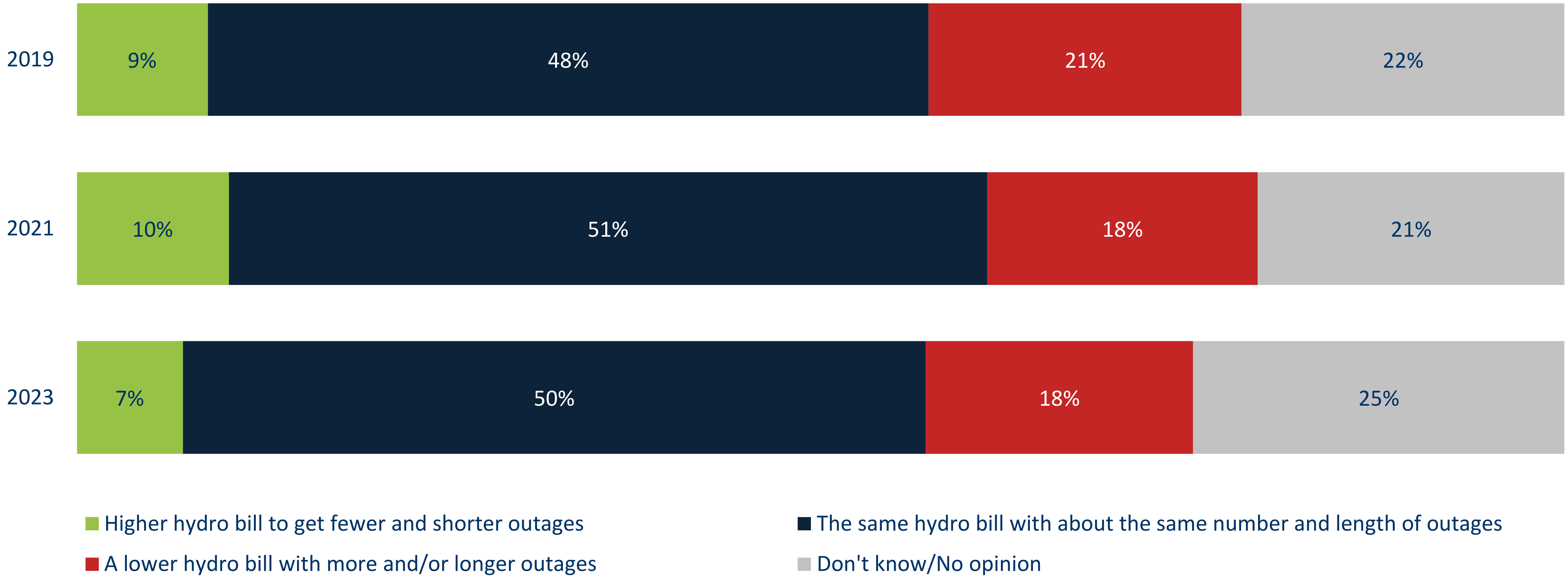
Orangeville Hydro uses vehicles, equipment, computer and IT systems to service the distribution system and manage customer information. How supportive are you of future equipment investments, recognizing it may mean an increase to your monthly bill?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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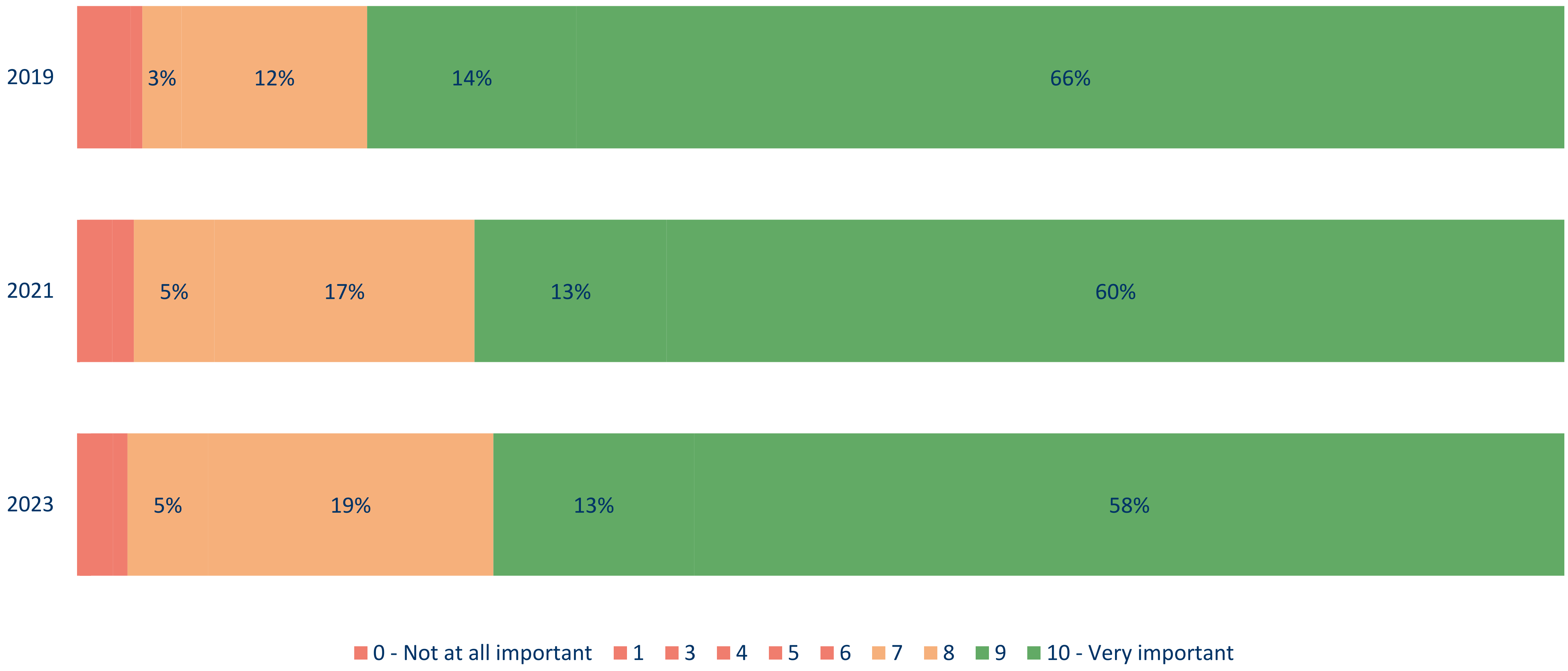
RELIABLE POWER TO MY HOME: Please rate the importance of the following priorities from 0 (not important at all) to 10 (meaning very important).



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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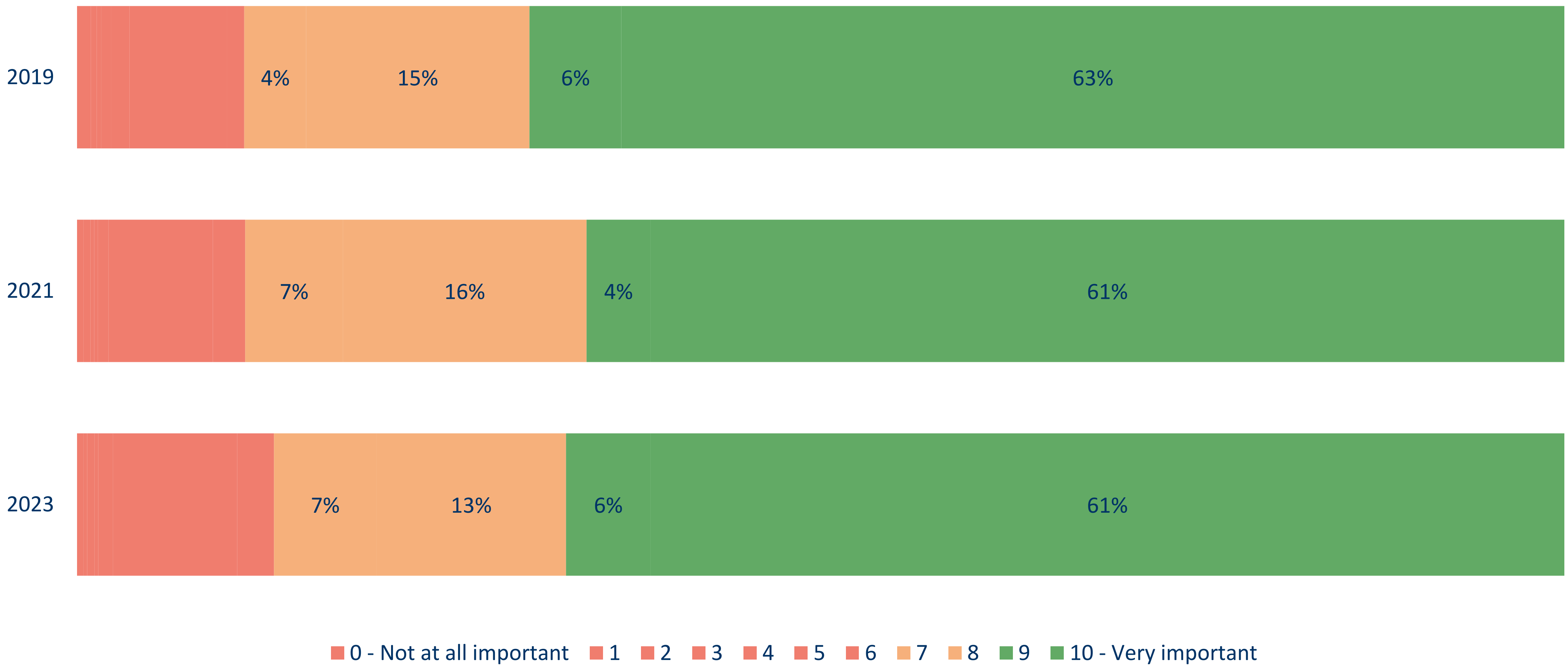
REASONABLE PRICES: Please rate the importance of the following priorities from 0 (not important at all) to 10 (meaning very important).



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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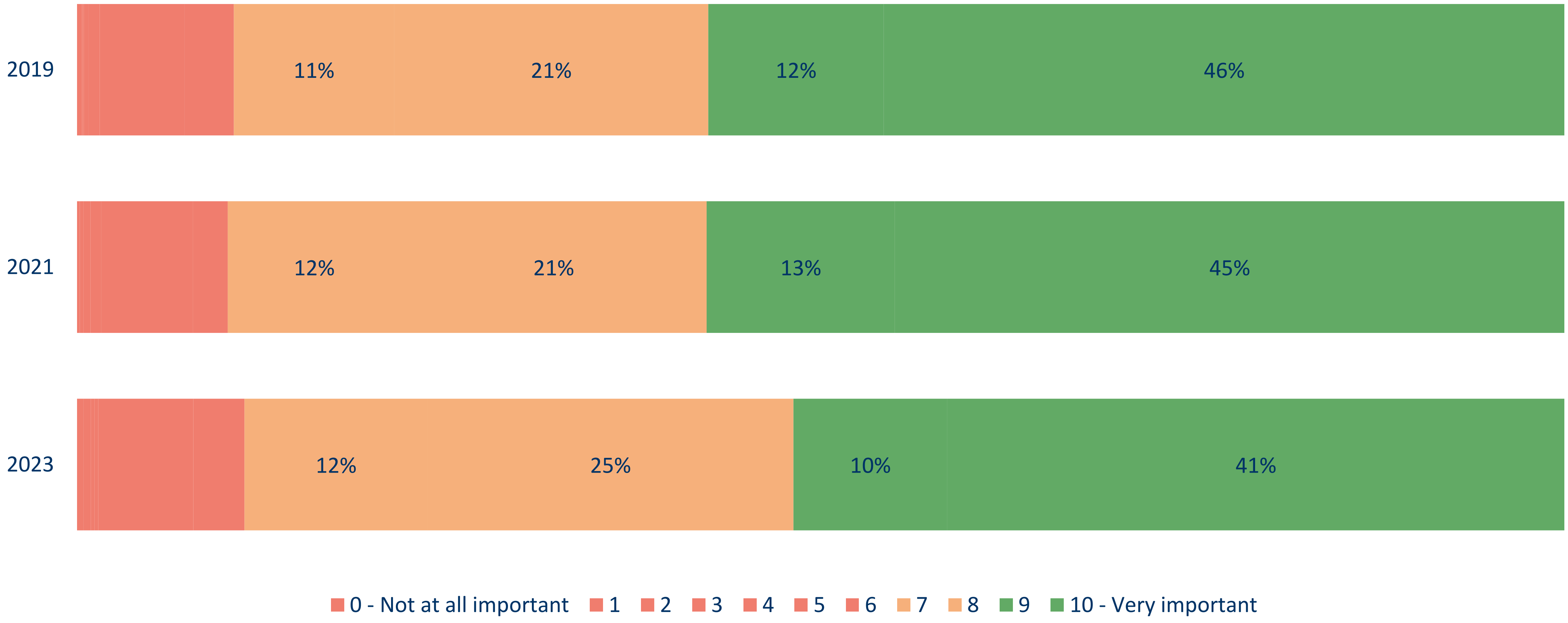
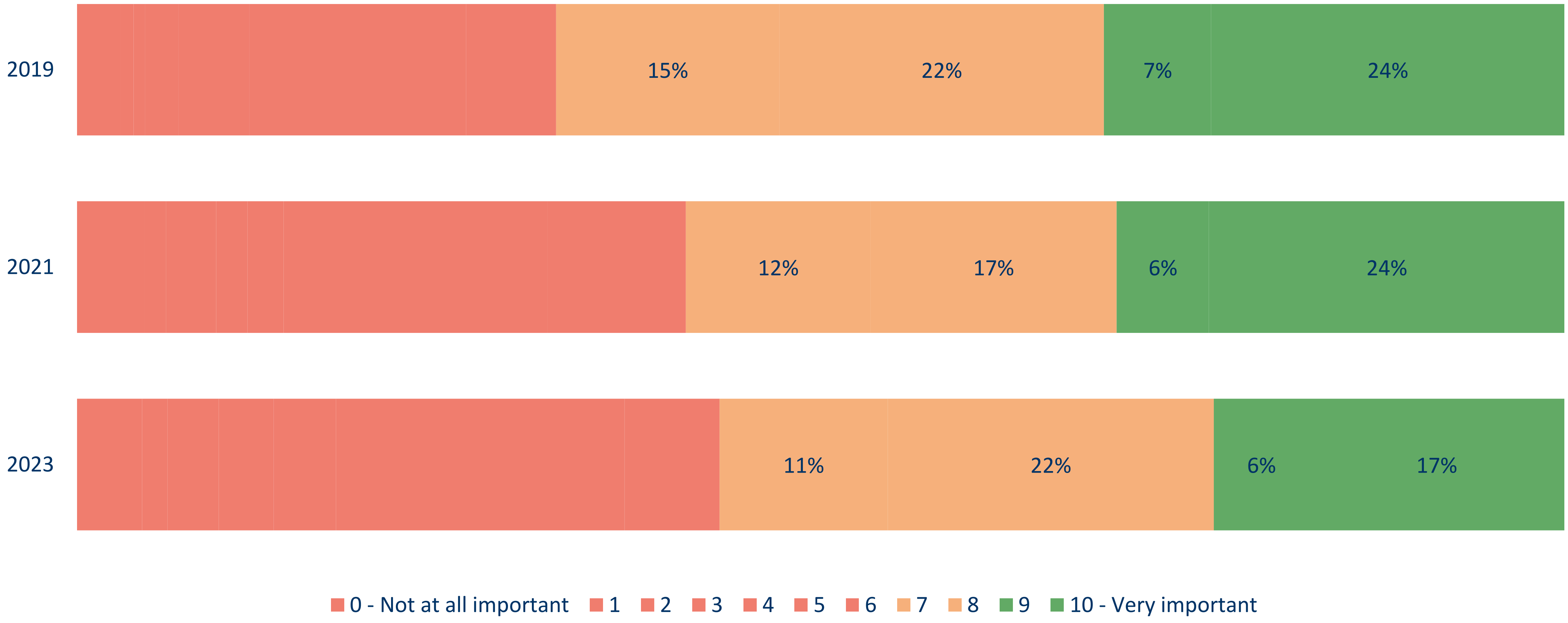
DEPENDABLE AND RESPONSIVE CUSTOMER SERVICE: Please rate the importance of the following priorities from 0 (not important at all) to 10 (meaning very important).



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

EDUCATION ABOUT ENERGY CONSERVATION PROGRAMS: Please rate the importance of the following priorities from 0 (not important at all) to 10 (meaning very important).



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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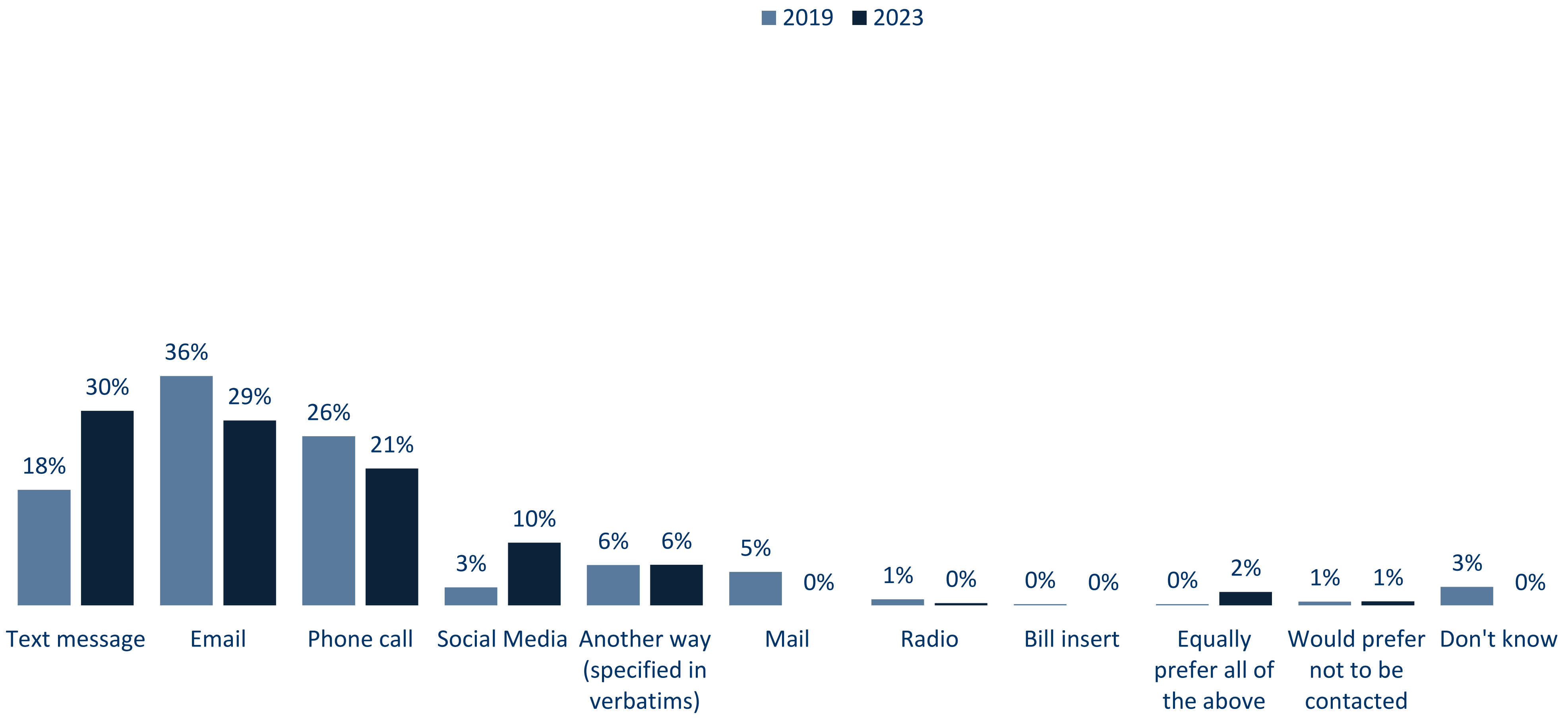
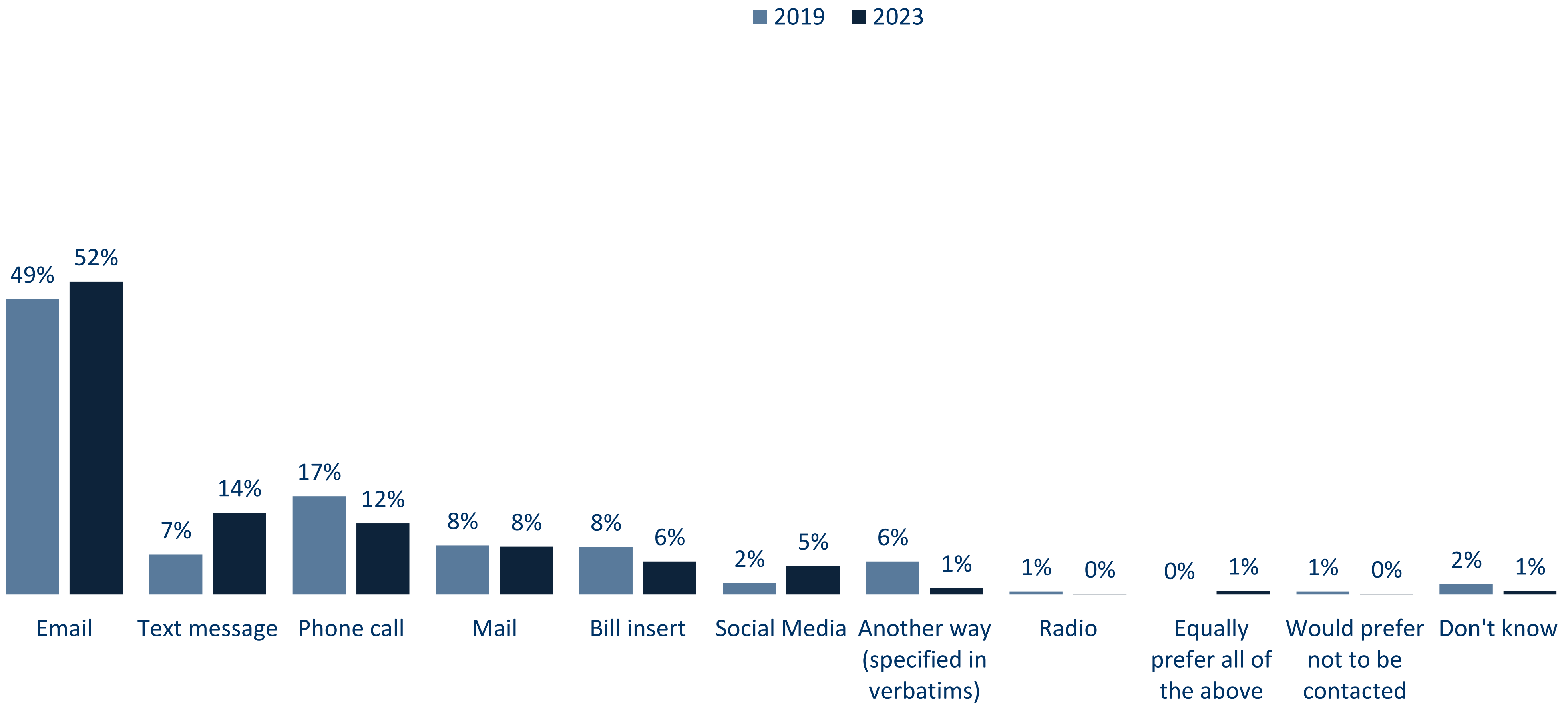
How would you most prefer to be alerted by Orangeville Hydro for URGENT INFORMATION items, such as unplanned service interruptions?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

How would you most prefer to be alerted by Orangeville Hydro for REGULAR CUSTOMER INFORMATION items, such as planned outages, system upgrades, etc.?



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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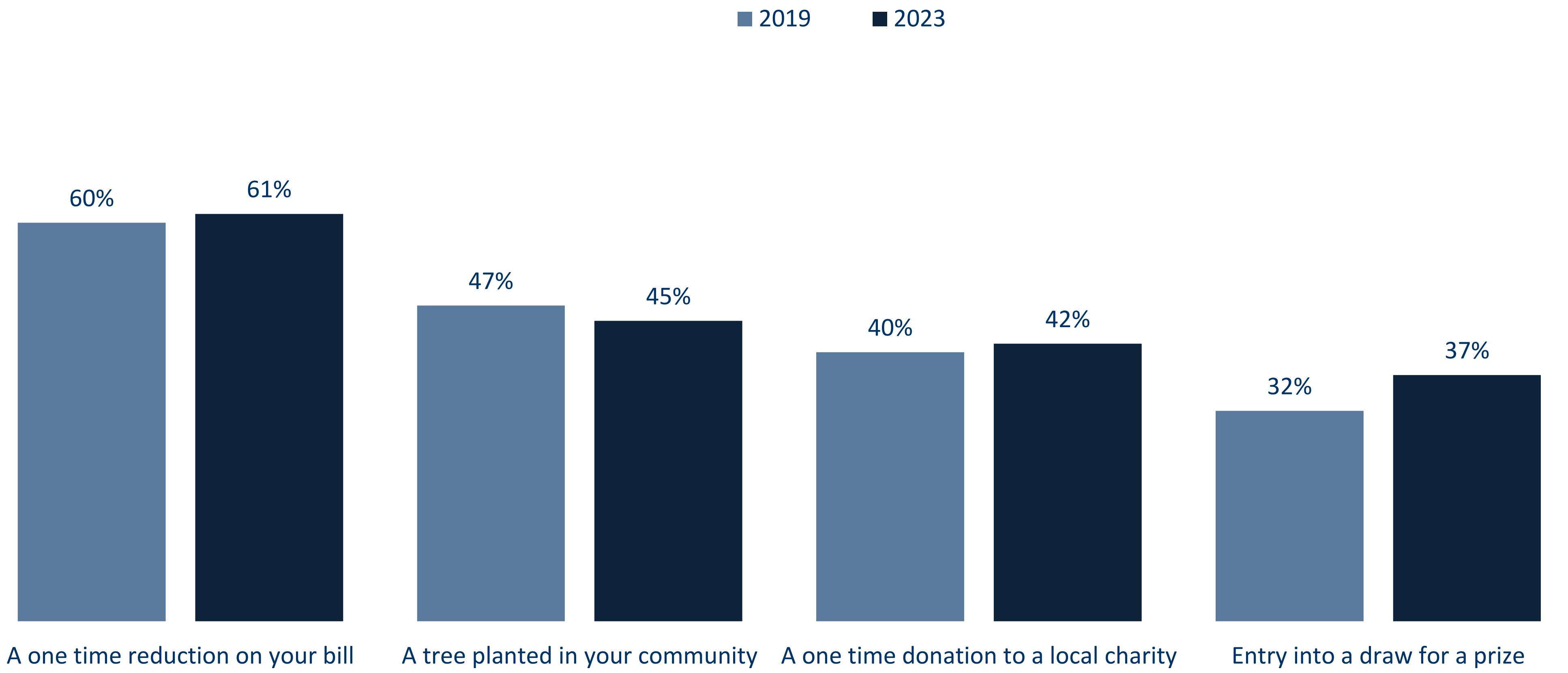
For each of the following offers, would they encourage you to SWITCH your monthly electric bill from regular TO EMAIL (electronic mail)?
% Selected 'Yes'



Weight: Aggregate weight for LDC based on customer_type
Filters: LDC: Orangeville Hydro

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Methodology

Methodology Summary

Commissioned by	Orangeville Hydro
Sample size	407 randomly selected customers
Margin of error	±4.8 percentage points, 19 times out of 20
Survey mode	Random telephone survey of customer base, CATI data collection
Survey sample	Residential and GS <50kWh customer lists provided by Orangeville Hydro
Time of calling	4PM-9PM Weekdays, 10AM-5PM Saturdays, scheduled callbacks
In-field dates	January 9-February 22, 2023
Language	English only
Survey author	Innovative Research/Electricity Distributors Association
Question Order	Core (OEB) questions then LDC-specific questions
Question Wording	Questions shown in report largely as asked; exact questionnaire available upon request
Survey Company	Advanis Gary.Offenberger@advanis.net

Methodology Details (1/4)

Target Respondents

The respondents of the survey were Ontario residents who are the primary bill payer or share the responsibility if residential or the person in-charge of managing the electricity bill at the organization if general service, and who resided within one of LDC's service territory(ies). Service territories were determined based on customer lists provided by the LDC.

Sample Size and Statistical Reliability

The final total completed surveys by LDC, and the associated margin of error for each, are shown below.

All margins of error are shown at a 95% confidence level.

- E.g., the margin of error associated with a sample size of 400 for a large (infinite) population is ±4.9 percentage points, 19 times out of 20.

Since each LDC has a finite population, we used the specific population sizes (i.e., the number of sample records received from each LDC) in the calculation of margin of error. Doing so is more accurate, and results in a narrower margin of error than if we simply assumed large (infinite) population for each.

Sample sizes were set according to the *LDC Customer Satisfaction Survey: Methodology & Survey Implementation Guide*, prepared for the Electrical Distributors Association (April 19, 2016 revision):

Where possible, sample size of n=400.
Distributors with 3000 to 4999 customers (residential + GS<50), n=300
Distributors with <3000 customers (residential + GS<50), n=200

Methodology Details (2/4)

Sampling Methodology

Advanis was provided sample lists from each LDC. Customer lists included all basic information required such as name, telephone number, region (where applicable), customer type (residential or GS<50), LDC fee, Annual or Monthly consumption values. Redhead then calculated which quartile group each resident belonged to by evenly dividing them into four groups within each region and customer type. These quartiles were calculated based on annual consumption value.

To minimize low response:

- Sample was loaded in batches to ensure the sample was fully utilized before moving onto fresh sample records;
- Calls were made between the hours of 4pm and 9pm ET; and
- Call backs were scheduled and honored between the hours of 9am and 9pm ET.

Sample Cleaning

Redhead cleaned the customer lists individually once received from each LDC to ensure the customer list counts reflected actual individual records that could be called. The following steps were taken during sample cleaning.

- All records with no phone numbers were removed.
- All phone numbers were checked to see if they were valid numbers (i.e., 10 digits, all numerical, etc.) and any bad cases were removed.
- When duplicates were detected based on phone number, the average of the consumption value was calculated and kept for one consolidated record. All others were removed.
- Residential and GS<50KW were separated into their own lists to be loaded and managed separately in the calling system.

Regions within each customer list were given a numerical value to be used for calling quotas.

Methodology Details (3/4)

Questionnaire

The survey instrument was provided by the Electricity Distributors Association (EDA) developed in conjunction with Innovative Research. The survey consisted of an introduction, overall satisfaction, power quality and reliability, billing and payment, customer service experience, communications, price, optional deeper dive questions, and final personal finance / sector mood measures. Additional questions were provided individually by some LDCs. These questions are not required as part of the survey and, as outlined in the methodology guideline, were asked after all the standard and required questions.

Data Collection

Computer aided telephone interviews (CATI) were conducted from **January 9-February 22, 2023.**

Quality Control

- Advanis trained its interviewers to understand the study's objectives;
- Detailed call records are kept by the automated CATI system, and are supplemented by output files to SPSS for productivity analysis (i.e., not subject to human error);
- The survey was soft launched in LDCs that had the most available sample, and the data was then checked before calling began in full for each;
- 100% of all surveys are digitally recorded for potential review (see next bullet);
- Advanis' Quality Assurance team listened to the actual recordings of five-ten percent of completed surveys and compared the responses to those entered by the interviewer to ensure that responses from respondents are properly recorded;
- Team Supervisors conduct regular more formal evaluations with each interviewer, in addition to nightly monitoring of each interviewer on their team;
- Project Managers closely monitored the progress of data collection, including call record dispositions;
- All SPSS code is reviewed by a more senior researcher;
- All report output is reviewed by a more senior researcher; and
- All values in the report are reviewed by another team member to ensure accuracy.

Methodology Details (4/4)

Analysis of Findings & Data Weighting

Results were weighted to match the proportion of low volume rate class records as provided to Advanis after cleaning of the sample file. Where a region flag was also provided, results were weighted to the low volume rate class within each region and regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

The Customer Satisfaction index scores have been highlighted and were calculated as described below, based on instructions in the Survey Methodology Guidelines. The "response values" referenced in the description below were also determined and provided by the survey authors.

Data analysis and cross-tabulation have been conducted using SPSS and Advanis' proprietary Online Reporting Environment software.

This **index score** is calculated using the following process:

Step 1: Weight data to n=400 with each low volume rate class proportionate to its share of LDC customer base.

Step 2: Rescale the index score variables onto the 0 to 1 scale as indicated by the response values detailed below.

Step 3: The average result of the questions asked for each OEB topic and the overall satisfaction score will be added together[3].

	B5
+	**[C6+C7+C8]** divided by 3
+	**[D9+D10]** divided by 2
+	**E11**
+	**F12**
+	**G14**
=	**Total cumulative scores**

Step 4: The total cumulative score from Step 2 will be divided by 6 to generate the **Customer Satisfaction Index Score** (bound between 0-1).

The chart on the following page illustrates how the **Customer Satisfaction Index Score** will be calculated.

As noted above, LDCs without a region flag were weighted to their low volume rate class proportion based on the cleaned sample file. LDCs with a region flag were weighted to their low volume rate class proportion within each region based on the cleaned sample file, and then regions were weighted proportionately to one another based on the customer base as provided in the cleaned sample file.

Specific values of the number of sample records, estimated population proportions, and final weighted sample counts within LDC are provided on the next slide.
The sum of the regional population proportions within an LDC may not equal 100% due to rounding.

Methodology Tables

Margin of error

LDC	Clean Customer Records from LDC	Completed Surveys	Sample Size as % of Customer list	Margin of Error @ 95% confidence level
Orangeville Hydro	10,691	407	3.81%	+/- 4.8%

* Since each LDC has a finite population, we used the specific population sizes (i.e., the number of sample records received from each LDC) in the calculation of margin of error. Doing so is more accurate, and results in a narrower margin of error than if we simply assumed large (infinite) population for each.

Sample weighting

Orangeville Hydro						
Regions Flagged in Sample	**Low Volume Rate Class**	**Sample Received** (Cleaned, Deduplicated)	**Rate Class Proportion**	**Estimated Customer Proportion**	**Weighted Sample Count**	**Unweighted Sample Count**
Grand Valley	Residential	931	95%	9%	35	35
	General Service < 50 kW	45	5%		2	2
Orangeville	Residential	9,019	93%	91%	343	343
	General Service < 50 kW	696	7%		26	27
TOTAL	**Residential**	**9,950**	**93%**	**100%**	**379**	**378**
	General Service < 50 kW	**741**	**7%**		**28**	**29**
					407	**407**

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780.229.1140

Appendix E – Material Investment Narratives

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This program consists of capital expenditures in response to requests from property developers to supply new housing infrastructure to serve residential subdivisions (single family, semi-detached and townhomes). Program expenditures are customer driven and include the installation of underground residential distribution infrastructure and transformers. The forecasted number of services is based on historical trends and anticipated future developments, through regular engagements with developers. Expenditures in this program are mandatory due to OHL's obligation under the Distribution System Code (DSC) and its Conditions of Service to connect new customers within its service territory.

Year	Number of Subdivisions	Number of New Connections
2024	3	281
2025	2	145
2026	2	117
2027	1	193
2028	2	219

The above table shows the forecasted number of developments and forecasted number of new connections. For 2024, the three developments consist of a larger subdivision in Grand Valley, a larger subdivision in Orangeville, and a small townhouse development in Grand Valley.

2. Timing

i. Start Date: The timing and schedule of the projects in this program are provided by the developers and their consultants. Through communicating with the developers and consultants, OHL remains aware of the forecasted timing of projects for each given budget year.
ii. In-Service Date: 2024-2028

iii. Key factors that may affect timing: The timing of this project is driven by customer demand, which can be unpredictable in changes directly affects estimated project timelines. Additional factors that could impact the schedule include:

Developer schedule: OHL does not start construction until an Offer to Connect is issued and the deposit is paid by the developer. These activities are dependent on the developer and can impact the timing of the project. OHL coordinates its long-term plans with the Town of Orangeville and Grand Valley through the municipal planning process to understand the areas slated for development and make the necessary plans to have infrastructure available.

Coordination with 3rd Parties: OHL coordinates these projects with gas, water and communication companies, especially for the work planned on public rights of way. The timing of these projects can be impacted by the availability of design information from these 3rd parties.

Resource challenges: The timing of these developer driven requests does not occur evenly throughout the year, which can create resource challenges with OHL's internal resources and contractors.

OHL mitigates these potential factors through coordination, where possible, with municipalities, suppliers, third parties, and developers.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	389	251	233	437	17	676	1242	541	571	532	748
Contributions	81	65	120	182	9	380	646	111	305	219	300
Capital (Net)	308	186	113	255	8	296	596	430	266	313	448

4. Economic Evaluation (Expansion Projects)

Economic Evaluations are completed in accordance with the Distribution System Code and Subdivision Agreements for each new subdivision expansion project in OHL's service territory. OHL works with developers to complete these economic evaluations.

5. Comparative Historical Expenditure

OHL's historical costs for this program are provided in the above table. The electrical distribution systems for these developer-driven projects are supplied and installed by the developer's contractor. The developer's electrical consultant, upon completion of the installation by its contractor, is required to provide the actual installation costs to OHL.

The below table shows the subdivision details for the historical years 2018-2022. 2022 was an anomaly year with zero new subdivision costs being capitalized in that year. The 2018 costs were higher than the historical average due to four subdivisions being capitalized in that year. The 2021 costs were higher than the historical average due to a large single detached home subdivision while other years mostly consisted of smaller townhouse developments.

Capitalization Year	Subdivision ID	Number of Customers	Description
2018	S17	45	Townhouse Development
2018	S23	30	Single Detached Homes Development
2018	S24	21	Townhouse Development
2018	S25	15	Townhouse Development
2019	S22	25	Townhouse Development
2019	S27	25	Townhouse Development
2019	S28	26	Townhouse Development
2020	S26	10	Townhouse Development
2020	S30	30	Single Detached Homes Development
2021	S29	98	Single Detached Homes Development

For future subdivision projects with completed economic evaluation, the project specific estimates have been included in the future costs for 2023 and 2024. For future years, the capital costs and capital contribution costs for the various projects have been estimated based on the historical information of similar past projects. While inflationary increases on material and labour costs are expected in future years, the main driver of the increased spending in future years is due to the increased quantity and size of the expected future developments compared to the prior years. In the forecast period, 2024 and 2028 are higher than other years because larger single detached home subdivisions are forecasted to be connected in those years. In 2024, there are three subdivisions expected. This includes two larger subdivisions, one with 153 customers, and one with 116 customers including an expansion to service the development. One of these developments has begun installation of the electrical distribution infrastructure while the other is at an earlier stage of development.

6. Investment Priority

The priority of this investment is high since it is a mandatory program driven by the need to provide customers with timely service connection in accordance with OHL's mandated service obligation under the DSC and OHL's Conditions of Service.

7. Alternatives Analysis

Subdivisions are typically designed by developers' electrical consultants with review and input by OHL. The schedule of each project under this program is determined entirely by the land developers. Construction is performed by the developers' contractors. The funding/ownership is as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreements.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	All new installations are designed and constructed as per OHL's latest standards and specifications to serve customers in the most efficient and cost-effective manner.
Customer Value	Customers benefit from having their new connection and the delivery of safe and reliable electricity.
Reliability	Since the probability of equipment failure is lower with new equipment, these projects are not expected to have a significant impact on reliability.
Safety	All new services are installed in accordance with OHL's standards, the Canadian Standards Association (CSA), Utility Standard Forum (USF) standards and Ontario Regulation 22/04.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* Customer Service Request – new subdivision request for connection.
ii. Secondary Drivers*:* Mandated Service Obligations.
iii. Information Used to Justify the Investment*:* Since these projects are for developer-initiated connections, this program in non-discretionary. Costs are recovered as per the Economic Evaluation in accordance with the Distribution System Code and Subdivision Agreement.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: New subdivision developments are designed based on the latest OHL Standards and these standards are updated reflect any changes in the Utility Standards Forum, Canadian Standard Association (CSA) standards, Regulation 22/04, or new materials (e.g. transformers, switchgear, etc.). OHL's standards and specifications are also in line with industry best practices.
ii. Cost-Benefit Analysis: All new installations are designed and constructed as per OHL's latest standards, specifications, and system requirements to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions. OHL reviews potential installation options with developers and their consultants and provides the corresponding costs of each option for the developers' consideration. OHL collects contributed capital through the Economic Evaluation as per the Distribution System Code and the Conditions of Service.
iii. Historical Investments & Outcomes Observed: OHL routinely connected new subdivision projects. These investments have driven OHL's customer and asset growth as well as ensured additional customers obtain access to the distribution system in the manner they require.
iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

This General Service Capital Contribution program involves non-residential customers who request service upgrades and connection of new services, and it is non-discretionary work. OHL has an obligation to connect these customers in accordance with the Distribution System Code (DSC) and OHL's Conditions of Service. It is difficult to predict connections as it is dependant on customer requests. However, customers will pay a capital contribution which reduces OHL's expenses for projects. From 2018 to 2022, the average cost was $96,000 with an average capital contribution of $75,000.

OHL budgets for approximately five new and upgraded general service customer demand projects consisting of a mix of overhead and underground servicing. The costs used for this are $80,000 Gross with a Capital Contribution of $40,000. This historical average over the 2018-2022 period had an average of $96,000 Gross with a Capital Contribution of $74,000. OHL has adjusted the forecast from historical based on a reduced quantity of large new connections based on the information available from the municipal planning portals.

2. Timing

i. Start Date: The timing and schedule of the projects in this program are provided by customers.
ii. In-Service Date: 2024-2028
iii. Key factors that may affect timing: The timing of this project is driven by customer demand, which can be unpredictable, and any change directly affects estimated project timelines.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	85	41	103	200	51	122	80	80	80	80	80
Contributions	79	41	83	132	37	49	40	40	40	40	40
Capital (Net)	6	0	20	68	14	73	40	40	40	40	40

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

OHL's historical costs for this program are provided in the above table. As shown through the year-to-year fluctuations, expenditures vary with customer/developer demand, economic activity, and the type of services requested. While inflationary increases are likely to occur in the future, these increases will be overpowered by the unknown variables such as the quantity of requests, the size of the required connection assets, and the location of the connection assets (ie. Overhead vs. Underground)

6. Investment Priority

The priority of this investment is high since it is a mandatory program driven by the need to provide customers with timely service connection in accordance with OHL's mandated service obligation under the DSC and OHL's Conditions of Service.

7. Alternatives Analysis

These projects are driven by the specific requirements of the customer. Design alternatives are limited as servicing options are standardized through OHL policies and practices, in line with its Conditions of Service. OHL reviews potential installation options with customers and provides the corresponding costs of each option for the customers consideration.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	All new installations are designed and constructed as per OHL's latest standards and specifications to serve customers in the most efficient and cost-effective manner.
Customer Value	Customers benefit from having their new connection and the delivery of safe and reliable electricity.
Reliability	Since the probability of equipment failure is lower with new equipment, these projects are not expected to have a significant impact on reliability.
Safety	All new services are installed in accordance with OHL's standards, the Canadian Standards Association (CSA), Utility Standard Forum (USF) standards and Ontario Regulation 22/04.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: Customer Service Request - Existing or new customers request a new or upgraded connection.
ii. Secondary Drivers: Mandated Service Obligations.
iii. Information Used to Justify the Investment: Since these projects are for customer-initiated connections and upgrades, this program is non-discretionary.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: New customer requests are designed based on the latest OHL Standards and these standards are updated reflect any changes in the Utility Standards Forum, Canadian Standard Association (CSA) standards, Regulation 22/04, or new materials (e.g. transformers, switchgear, etc.). OHL's standards and specifications are also in line with industry best practices.

ii. Cost-Benefit Analysis: All new installations are designed and constructed as per OHL's latest standards, specifications, and system requirements to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions. OHL reviews potential installation options with customers and provides the corresponding costs of each option for the customers consideration.

iii. Historical Investments & Outcomes Observed: OHL collects contributed capital for a portion of the costs in this program. Capital contributions toward the cost of all customer demand projects are collected by OHL in accordance with the DSC and the provisions of its Conditions of Service. All assets installed under this project are fully owned by OHL. OHL has historically responded to customers and provided the relevant service within the timeline outlined in the DSC.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

This Residential Capital Contribution program involves residential customers who request service upgrades and connection of new services (other than subdivisions) and it is considered non-discretionary work. OHL has an obligation to connect these customers in accordance with the Distribution System Code (DSC) and OHL's Conditions of Service. While it is difficult to predict the quantity of connection and upgrades as it is dependent on customer OHL is forecasting an average of 27 residential customer requests over the 5-year horizon. However, customers will pay a capital contribution, for work beyond the Basic Connection Credit, which reduces OHL's expenses for projects.

2. Timing

i. Start Date: The timing and schedule of the projects in this program are provided by customers.
ii. In-Service Date: 2024-2028
iii. Key factors that may affect timing: The timing of this project is driven by customer requests, which can be unpredictable, and any change directly affects estimated project timelines.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	20	11	37	16	23	22	30	30	30	30	30
Contributions	20	9	37	14	16	22	25	25	25	25	25
Capital (Net)	0	2	0	2	7	0	5	5	5	5	5

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

OHL's historical costs for this program are provided in the above table. As shown through the year-to-year fluctuations, expenditures vary with customer/builder demand, economic activity, and the type of services requested. While inflationary increases are likely to occur in the future, these increases will be overpowered by the unknown variables such as the quantity of requests, the size of the required connection assets, and the location of the connection assets (i.e., Overhead vs. Underground). The past 5-years have an average Gross Capital cost of approximately $21k. Looking forward, OHL is forecasting upward pressure on the average quantity of service upgrades because of electric vehicle chargers and heat pumps.

6. Investment Priority

The priority of this investment is high since it is a mandatory program driven by the need to provide customers with timely service connection in accordance with OHL's mandated service obligation under the DSC and OHL's Conditions of Service.

7. Alternatives Analysis

These projects are driven by the specific requirements of the customer. Design alternatives are limited as servicing options are standardized through OHL policies and practices, in line with its Conditions of Service. OHL reviews potential installation options with customers and provides the corresponding costs of each option for the customers consideration.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	All new installations are designed and constructed as per OHL's latest standards and specifications to serve customers in the most efficient and cost-effective manner.
Customer Value	Customers benefit from having their new connection and the delivery of safe and reliable electricity.
Reliability	Since the probability of equipment failure is lower with new equipment, these projects are not expected to have a significant impact on reliability.
Safety	All new services are installed in accordance with OHL's standards, the Canadian Standards Association (CSA), Utility Standard Forum (USF) standards and Ontario Regulation 22/04.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* Customer Service Request - Existing or new customers request a new or upgraded connection.
ii. Secondary Drivers*:* Mandated Service Obligations
iii. Information Used to Justify the Investment*:* Since these projects are for customer-initiated connections and upgrades, this program is non-discretionary.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: New customer requests are designed based on the latest OHL Standards and these standards are updated reflect any changes in the Utility Standards Forum, Canadian Standard Association (CSA) standards, Regulation 22/04, or new materials (e.g. transformers, switchgear, etc.). OH's standards and specifications are also in line with industry best practices.

ii. Cost-Benefit Analysis: All new installations are designed and constructed as per OHL's latest standards, specifications, and system requirements to serve customers in the most efficient and cost-effective manner while providing system flexibility under normal and emergency conditions. OHL reviews potential installation options with customers and provides the corresponding costs of each option for the customers consideration.

iii. Historical Investments & Outcomes Observed: OHL collects contributed capital for a portion of the costs in this program. Capital contributions toward the cost of all customer demand projects are collected by OHL in accordance with the DSC and the provisions of its Conditions of Service. All assets installed under this project are fully owned by OHL. OHL has historically responded to customers and provided the relevant service within the timeline outlined in the DSC.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This system renewal program is a combination of three subprograms:

PME Switchgear Replacements

PME switchgears are used to provide switching and fusing functionality to the underground distribution system as well as connect smaller cables to main trunk lines. OHL's population of PME switchgear has experienced failures leading to large feeder-wide outages. In addition to this, the existing mild steel units are experiencing excessive corrosion from road, sidewalk, and parking lot salt due to winter maintenance activities. The excessive corrosion poses a risk to both reliability and public safety. OHL has begun a formal annual replacement program. OHL forecasts to replace one PME switchgear each year under this renewal program. The replacements will be like-for-like except that new units will have a stainless-steel enclosure to prevent premature corrosion issues. This program is for planned PME replacements based on asset condition assessments and field inspections. Unplanned replacements due to units completely failing in the field are placed under a separate program code (H00).

Distribution Transformer Replacements

Transformers are used to change the voltage from a distribution level to a customer service voltage level. Transformers are identified for replacement when they become damaged, become inoperable, leak oil, pose a safe risk, become corroded beyond refurbishment, or become overloaded. This program includes both the proactive and reactive replacement of transformers. OHL forecasts to replace nine transformers per year under this program. Since this program includes reactive replacements, the quantity and costs will fluctuate from year to year.

Padmount Enclosure Refurbishments

LDC assets like pad-mounted transformers and switching units are expected to have a useful life of 30 to 50 years. Corrosion can severely limit the actual life expectancy. In many cases, LDC's are forced to replace an otherwise "good" unit due to safety concerns from enclosure corrosion, even though the asset was expected to remain in service for decades. OHL plans to utilize a third party to complete a proactive treatment using dual flow low pressure cold spray corrosion treatment to existing corroded pad-mount transformers and switchgear. OHL forecasts the treatment to be applied to 20 units each year. This program will avoid the replacement of the unit and extend the life of the asset in the field. This program is an in-field program where the unit's enclosure is refinished while the unit remains active in the field. No replacements are included within costs of this program.

Distribution Transformer & PME Switchgear Purchases & Net Movements

Also included in the costs B00 program costs are non-field related net movement of transformers and PME switchgears. When new transformers and PME are purchased, the purchase costs are capitalized as stand-by equipment per OHL's Capitalization Policy and IAS 16 - IFRS through the B00 job cost program. Also, movements of transformers and PME switchgear from stock to the field under other capital projects is tracked through the B00 job cost program as negative value. This has a significant impact on the overall B00 program costs in the historical years.

Figure 1 - PME switchgear that was removed from service due to excessive corrosion

Figure 2 - Transformer requiring replacement due to oil leak

Figure 3 - Transformer with corrosion and a candidate for in-situ refurbishment

2. Timing

i. Start Date: 2024
ii. In-Service Date: 2024 to 2028
iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
   a. Availability of labour and financial resources to accommodate higher priority or non-discretionary projects
   b. Inclement weather conditions
   c. Supply chain issues such as lack of availability or delayed shipments from vendors

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028

Capital (Gross)	-14	101	270	95	123	171	161	161	161	161	161
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	-14	101	270	95	123	171	161	161	161	161	161

The historical expenditures are significantly impacted by the net movement and purchases of transformers and PME switchgear.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

The historical expenditures are significantly impacted by the net movement and purchases of transformers and PME switchgear.

Forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. Per unit costs for tasks such as a transformer replacement are subject to significant variability from project to project due to factors such as:

- Planned Replacement vs Emergency Unplanned Replacement
- Polemounted vs Padmounted
- Front-lot vs Rear Lot
- Single Phase vs Three-Phase
- Transformer Sizing
- Transformer Design
- Concrete foundation replacement vs not replacing concrete foundation
- Ground grid replacement vs not replacing ground grid
- Inflationary increases on material, labour, and contractors over time

The below table provides the quantity of units replaced each year and the average unit replacement cost.

Year	Quantity	Average Unit Price
2018	1	$7,729
2019	21	$8,158
2020	5	$8,153

2021	16	$6,375
2022	2	$10,261

This table does not directly relate to the historical costs in Section 3 because the costs in Section 3 are significantly impacted by the net movement and purchases of transformers and PME switchgear. This table with the historical quantity of units and unit replacement costs is directly related to unit replacement costs and excludes net movement of inventory and new purchases.

In 2024, OHL is forecasting replacing nine transformers per year at an average replacement cost of $9,156 per unit. The unit price has been increased to account for inflationary increases on material, labour, and contractors.

In 2024, OHL is forecasting replacing one PME switchgear per year at an average replacement cost of $44,998 per unit. This is a new planned program and does not have comparable historical values. The new PME switchgear will have stainless steel enclosures to reduce the risk of corrosion. The stainless-steel enclosure costs more than the mild steel enclosures for PME switchgears purchased before 2023.

In 2024, OHL is forecasting completing surface refurbishment on 20 transformers at an average price of $1,699 per unit. This is a new planned program and does not have comparable historical values.

6. Investment Priority

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 5 out of 16. In order to maintain system integrity and reliable service to the customers, OHL plans to replace its overhead and underground transformers (e.g., pole-top and padmounted transformers) and padmounted switchgear with the new standardized units based on prioritization from asset condition assessments and inspection results. If not replaced, the identified transformers will deteriorate further and will fail more often to a level that is not manageable by OHL resource capacity and would not be tolerable by the customers.

7. Alternatives Analysis

Some of the options that are considered when evaluating a transformer and switchgear replacements include:

i. **Do nothing and run to fail:** As long as there are no safety (corrosion or oil leaks) issues present, this is OHL's typical approach for transformer replacement. While this can be employed for unplanned and unexpected failure of transformers, it is not sustainable to carry this out for all transformer replacements. Customers would experience longer and increased unexpected outages. In addition, replacing transformers and switchgear reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase due to overtime rates being higher than normal working hours. This ultimately would increase reactive renewal costs.

ii. **Like for like replacement (proactive):** This is the preferred approach for switchgear and transformer when inspections and asset condition assessments dictate the unit should be replaced. The proposed proactive replacement of unsafe transformers and switchgear will ensure that the number of unplanned outages remains minimal by avoiding asset failures so that the customers have access to reliable electricity for their needs. Costs are reduced when compared with completing all transformers under a reactive program because reactive replacements generally incur a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase due to overtime rates being higher than normal working hours.

iii. **Upgrade to address overloading issues:** OHL replaces transformers that are identified as overloaded through our OMS Transformer Loading feature or transformers that are nearing capacity at the time of new customer connections with future overloading expected.

iv. **Surface Refurbishment:** Certain switchgear and transformers will be eligible for in-situ surface refurbishment based on the level of corrosion and the age of the asset. OHL plans to proactively refurbish 20 units annually.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment

Efficiency	The infrastructure will be upgraded to current OHL specifications and design standards to improve future life expectancy. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time. Refurbishment, where applicable, is more cost effective than replacement.
Customer Value	The proactive refurbishment and planned replacement strategy of this program is less costly than only relying on reactive replacements, by planning the work during regular working hours.
Reliability	The planned replacement of switchgear on an annual basis reduces the risk of large feeder-wide outages from failed switchgear. Continued replacement of failing and deteriorated transformers assists in maintaining the existing reliability levels. The planned enclosure refurbishment program will extend the life of the asset and reduce the risk of premature failure and replacement which assists in avoiding both planned and unplanned outages.
Safety	Replacement of corroded pad mounted equipment is required to reduce the risk to the public. Significant corrosion within the lids, doors, and skirts creates holes in the metal and removes the barrier between the public and energized equipment. Excessive corrosion to the oil-filled tank can cause a leak which creates an environmental risk. The enclosure refurbishment program reduces the risks of environmental safety concerns from oil leaks as well as reduces the risk of exposed energized apparatus due to holes in the metal enclosure.

2. INVESTMENT NEED

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Replacements

   a. Main Driver*:* Failure Risk - The transformer and switchgear program is a renewal program meant to replace aging/deteriorating assets that are deemed to have failed or are at a higher risk of failure. OHL is required to ensure that OHL's infrastructure does not negatively impact the health and safety of the public, customers or OHL's employees. From the most recent asset condition assessment for padmounted transformers, 5% (46) are in poor health with an additional 2% (64) in very poor condition. For polemounted transformers, 24% (83) are in poor health with and additionally 10% (33) in very poor health. From the most recent asset condition assessment, there are no switchgear in poor or very poor health. There are 14% (12) switchgear in a fair condition.

b. Secondary Driver*:* Reliability - The secondary driver is Reliability. The risk to the utility and the customer is that the asset will fail completely and result in an outage that negatively affects reliability and therefore customer satisfaction.

ii. Refurbishments:

a. Primary Driver*:* Failure Risk - The driver for the refurbishment program is based on the finding that the mild steel transformers and switchgears are corroding faster than originally planned. The premature corrosion leads to issues such as leaking oil or holes exposing the energized parts of the transformer or switchgear. To avoid significant replacements in the coming years, OHL plans to utilize proactive enclosure refurbishment/refinishing for in-field assets.

iii. Information Used to Justify the Investment*:* Along with its ACA, OHL uses a geospatial mapping system along with the field inspection reports and infrared scanning to identify and prioritize which units to replace or refurbish. Replacements are completed on a unit-by-unit basis while in-field refurbishments are normally done by an entire subdivision. In addition, reliability data has been used, where OHL has identified that reliability has been worsening due to switchgear failures. OHL has therefore implemented a new program to replace one switchgear a year.

3. INVESTMENT JUSTIFICATION

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new replacements are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. Transformers and switchgear with extensive serious deterioration and in critical condition are replaced immediately while others with varying degrees of degradation are prioritized for proactive replacement based on condition and criticality. Enclosure refurbishment is a commonly accepted practice by Ontario LDCs to extend the service life of existing assets.

ii. Cost-Benefit Analysis: OHL replaces the minimum level of transformers based on safety concerns (corrosion or oil leaks) or imminent failure (Infrared Scan) to ensure the cost stays as low as possible while maintaining reliability. Taking a proactive approach of replacing one switchgear a year will reduce replacement costs by reducing the risk of unplanned failure outside of normal working hours which are more costly to replace due to overtime labour rates being higher than normal working hours labour rates. The proactive approach will also reduce outage time for customers and help provide customers with better reliability. In addition, refurbishment of corroded pad-mounted equipment is significantly less costly than a replacement.

iii. Historical Investments & Outcomes Observed: Historical costs are presented in the above table. The proactive replacement strategy of the program as planned is less costly than exclusive reactive replacements. OHL's strategy has been to sustain the system and continue to maintain reliability and continue to minimize outages. Reliability levels due to transformer failures have typically been maintained. Reliability concerns due to switchgear failures have been increasing, hence OHL starting a proactive replacement of one switchgear per year.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The program is used for reactive and planned major component replacements for distribution assets other than poles, meters, transformers, and substations as these assets have their own separate project codes. The assets that are allocated to this program are PME switchgear, load break switches, cut-outs, in-line switches, primary cables, and automatic tension sleeves. This program is used for major component replacements that are not part of a separate larger System Access, System Renewal, or System Service projects. In 2024, this program consists of two sub-programs:

1. **Replacement of Major Components**: This program is used for reactive replacements of failed or about to fail PME switchgear, load break switches, inline switches, primary cables, and cut-outs. In the most recent asset condition assessment, it was found that 17% (16) of inline switches were in poor condition and 2% (2) were in very poor condition. For switchgear, 14% (12) were in fair condition. This program is also used for capital replacement requirements as a result of infrared thermal imaging. This program has also been used for short term programs such as increase storm guying as required, replacing defective insulators, and increasing the quantity of lightning arresters in the field. Asset inspections, such as visual and infrared, are used to determine the condition of the asset. When deemed necessary, a proactive replacement is planned prior to complete failure. An example of this is replacing multiple inline switches or fused cutouts after an annual infrared scan finds thermal anomalies that are not repairable. The replacements would be planned and scheduled to avoid waiting for a complete failure that could impact customer's reliability and potentially be more expensive if the failure occurred outside of normal operating hours. The forecasted $50,000 per year for this program is based on one PME switchgear will fail each year along with hot spot replacements of equipment such as inline switches, cutouts, and arresters as required and the replacement of water-ingressed primary cable.
2. **Automatic Tension Sleeve Replacement:** This is a focused program to replace the existing automatic tension sleeve (“Quick Sleeves”) installed on OHL’s primary distribution system. In 2020 and 2022, there have been automatic tension sleeve failures within OHL’s distribution system. These failures create the potential for a public safety incident and significantly impact the reliability to customers. Furthermore, in 2023, there was an automatic tension sleeve failure upstream of OHL’s service area causing a loss of supply to OHL’s largest feeder. When these

failures occur, the splice connection fails causing a conductor to fall to the ground. This creates a significant safety concern as well as, depending on the location of the failure, a large multi-feeder-wide outage. OHL is aware of other electric utilities that have completed a similar process and OHL has determined the correct course of action is to replace all the existing automatic tension sleeves on the primary conductors with permanent compression tension sleeves. OHL's audit has identified 531 automatic tension sleeves at 190 locations. As explained above, these assets have an increased safety risk to the public and employees. OHL has assessed the risk of these and has identified that these need to be replaced as soon as practical. OHL has therefore developed a plan that will replace all 531 automatic tension sleeves with permanent compression sleeves by the end of 2024. OHL plans to replace 100 automatic tension sleeves in 2023 and the remaining 431 tension sleeves in 2024.

2. Timing

i. Start Date: 2024
ii. In-Service Date: 2024 to 2028, automatic tension sleeve replacement is planned to be completed in 2024.
iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
   a. Availability of labour and financial resources to accommodate higher priority or non-discretionary projects
   b. Inclement weather conditions
   c. Supply chain issues such as lack of availability or delayed shipments from vendors

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	19	0	27	60	33	142	227	50	50	50	50
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	19	0	95	60	33	142	227	50	50	50	50

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The historical costs in 2018 were to install additional lightning arresters throughout the 27.6kV distribution system, replace failing inline switches, and to replace equipment that was identified as failing during infrared thermal inspections.

The historical costs in 2020 were to replace a failed PME switchgear which caused a large unplanned feeder wide outage.

The historical costs in 2021 were replacing remaining at-risk EPAC insulators after these insulators were identified as the root cause of multiple pole fires, replacement of primary cables due to water ingress issues, installation of a load break switch, and the installation of additional storm guys after inspections identified a non-compliant section of line.

The historical costs in 2022 were to replace a PME switchgear.

6. Investment Priority

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 6th out of 16. The planned portion of this program are needed to reduce the quantity of deteriorated assets in the distribution system and comply with external codes/standards. Proactively identifying and replacing assets, such as automatic sleeves, reduces the risk of prolonged, unexpected power outages. This aligns with the customer's need for the utility to maintain a similar level of reliability and minimize outages. There is a portion of this program that includes reactive replacements to already failed equipment such as water-ingressed primary cables, failed switches, and failing equipment identified by infrared thermal imaging. These are often replacements are non-discretionary as they are required to either restore power immediately or avoid imminent or repetitive outages to customers.

7. Alternatives Analysis

The options that are considered when evaluating asset replacements under this program include:

i. **Do nothing and run to fail:** If there are no safety concerns, OHL considers this as a potential option for certain assets. This is apparent by the fact that this program does include costs for replacing already failed assets or failing assets, even if they did fail before their typical useful life. While this can be employed for some major assets, it is not sustainable to carry this out for all assets such as automatic tension sleeves. Running equipment to failure is also not acceptable once it has been identified as having a high risk of imminent failure such as primary cables with water-ingress, under-guyed pole lines, or overheating equipment identified during infrared thermal inspections. Customers would experience longer and increased unexpected outages. In addition, replacing equipment reactively generally incurs a premium as they are unplanned and potentially replaced outside normal hours. This ultimately would increase reactive renewal costs.

ii. **Like for like replacement (proactive):** This is the preferred approach for the automatic tension sleeve removal program. The proposed proactive replacement of automatic tension sleeves will reduce the risk of asset failures so that the customers have access to reliable electricity for their needs. The automatic tension sleeves will be replaced with compression tension sleeves that meet the latest industry standards. This is the preferred approach for other major components when justified from inspections and asset condition assessments. The proactive replacement of overheating inline switches and primary cables with water-ingress have occurred in the past and are forecasted to occur in the future.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current OHL specifications and design standards to improve future life expectancy. Proactive replacement of an asset, such as primary cables with water-ingress or overheating switches, is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time.

Customer Value	The proactive planned replacement strategy of this program, such as the replacement of the automatic tension sleeves, provides value to customers by increasing the safety and reliability of the distribution system.
Reliability	The planned replacement of the automatic tension sleeves reduces the risk of large feeder-wide outages from connection failures. Continued replacement of failed and failing major assets, such as PME switchgear and primary cables, assists in maintaining the existing reliability levels.
Safety	The planned replacement of the automatic tension sleeves reduces the risk of energized conductors falling to the ground from connection failures. This is an unacceptable risk to the general public and OHL staff. Hardware replacements, such as the installation of additional storm guys in 2021, harden the existing pole lines to reduce the risk of multiple poles failing and falling to the ground during windstorms.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* Failure and Failure Risk – The reactive portion of this program is to replace equipment that has already failed. The proactive portion of this program is to replace equipment that is at high-risk of failure or has an unacceptable failure mode.
ii. Secondary Drivers: Safety – The replacement of the automatic tension sleeves with compression sleeves reduces the risk of energized conductors falling to the ground. Hardware replacements, such as the installation of additional storm guys in 2021, harden the existing pole lines to reduce the risk of multiple poles failing and falling to the ground during windstorms.
iii. Information Used to Justify the Investment: The ACA is used to justify the continued investments in this program. In the most recent asset condition assessment, it was found that 17% (16) of inline switches were in poor condition and 2% (2) were in very poor condition. For switchgear, 14% (12) were in fair condition. For specific immediate reactive replacements under this program, such as failed PME switchgear and primary cables with water-ingress, are found either due to a power outage or field inspections. Infrared thermal scanning is used to determine which specific assets require replacement each year. Recent issues with

automatic tension sleeves justified an audit of OHL's distribution system to determine the quantity of automatic tension sleeves installed.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new replacements are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. PME switchgears are now purchased with a stainless-steel enclosure to reduce the risk of the units requiring premature replacement due to corrosion. The automatic tension sleeve replacement program was created with the consultation of an industry safety professional to learn about comparable programs from other electric utilities.

ii. Cost-Benefit Analysis: A portion of the costs related to this program are directly related to replacements of equipment that has failed or is at an unacceptable risk of failing in the future. These costs are required to either restore power immediately or the costs are related to maintaining the existing reliability levels. The costs for the automatic tension sleeve removal program are required to reduce the risk of additional failed connections causing wide-spread multi-feeder outages as well as reduce this risk of conductors falling to the ground.

iii. Historical Investments & Outcomes Observed: Historical costs are shown in the table above. Reactive replacements have been required to maintain reliability levels. Many projects within this program have been identified based on root-cause analysis of past outages.
   a. **Water-ingressed Primary Cable replacements:** Primary cables with water ingress are replaced with strand-blocked cable to reduce the risk of reoccurrence. Also, OHL is transitioning to alternate termination manufacturers with increased water-ingress capabilities as an additional layer of protection.
   b. **PME Switchgear:** OHL's PME switchgear specifications now included stainless-steel enclosures to reduce this risk of premature failure from

corrosion. A proactive PME-replacement program began in 2023 to reduce the risk of unplanned switchgear failures.

c. **In-line Switches:** Inline switch failures led to a joint investigation with the manufacturer to improve installation methods to reduce the risk of future switch failures.

d. **Legacy EPAC Insulator:** After multiple pole fires in the 2010s caused by failed legacy EPAC insulators, OHL audited the overhead system and replaced all legacy EPAC insulators in 2021. This reduced the risk of additional pole fires due to a similar failure mode.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

v.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

OHL owns, operates, and maintains 13,333 revenue meters either installed on its customers' premises for the purpose of measuring electric consumption or in stock for future use. All existing residential and general service (GS) customers (<50kW) were equipped with smart meters in 2009/2010. The Metering program includes the supply, replacement, and maintenance of OHL's metering assets, in compliance with Measurement Canada requirements. OHL conducts both meter sampling and re-verification in compliance with Measurement Canada requirements to extend the life of existing meter assets to reduce life cycle costs. The activities falling within the scope of this program include:

(1) Purchase of new residential and commercial meters for new installations, to replace failed existing meters, and to begin a paced renewal program for existing smart meters. OHL is looking to purchase new meters each year over the forecast period. The forecasted quantities for purchase are: 1,202 in 2024, 1,424 in 2025, 1,656 in 2026, 1,424 in 2027, and 1,712 in 2028.

(2) Continued replacement of wholesale meters at time of seal expiration. The timing of these replacements is dependent on the seal expiry of the existing meters. There are forecasted replacements in 2025 (one wholesale meter), 2026 (one wholesale meter), and 2027 (four wholesale meters).

(3) Labour, trucking, and contractor costs to complete the required reverification and sampling as per Measurement Canada requirements.

(4) Costs to upgrade the remaining MIST interval customer with legacy phoneline metering installations with upgraded cellular communications. This program will be paced over 2024, 2025, and 2026 to complete the remaining locations (approx. 60 over three years).

Since these investments are required by the DSC and Measurement Canada requirements, they are considered non-discretionary. Customer connection requests are fulfilled consistent with OHL's Conditions of Service. Through the implementation of this program, OHL can continue to accurately and correctly measure and bill customers for the electricity that they use and satisfy the OEB "Billing Accuracy" requirement to have 98% billing accuracy.

2. Timing

i. Start Date: 2024
ii. In-Service Date:2024 to 2028
iii. Key factors that may affect timing: There is a risk to the timing of this program due to the following factors:
   - Delays due to inclement weather or restricted access by customer
   - Supply chain issue causing delayed material delivery (Material delays are prevalent across the metering industry at this time)
   - Unforeseen cost increases or labour shortages
   - Unforeseen issues with third party metering test shops

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	126	109	0	171	19	203	243	362	450	378	441
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	126	109	0	171	19	203	243	362	450	378	441

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

OHL's metering program is an ongoing annual expenditure. Depending on the number of new installations, timing of bulk meter deliveries, meter failures, or seal expiries in any given year, costs will fluctuate from year to year. Historical per unit costs were used for forecasting future costs. This cost was adjusted for estimated changes in labour and material costs.

6. Investment Priority

This investment program is classed as a high priority and non-discretionary due to the obligation to obtain meters to connect new customers and the need to comply with mandated service obligations as defined by the DSC and Measurement Canada.

7. Alternatives Analysis

This is a mandatory project and a regulatory requirement. Metering asset management is governed by Measurement Canada regulations and customer requirements to connect new and upgraded services. No alternatives were considered since failure to perform the work to install, repair, replace and/or reseal meters would be in violation of the DSC and Measurement Canada requirements, and has the potential to negatively impact the reliable source of billing settlement data. Currently, OHL is not planning on moving to a new AMI system within the horizon of this DSP.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	OHL uses standardized designs and material to build efficiencies into the process. Customer connection requests are fulfilled consistent with OHL's Conditions of Service. Additionally, through addressing meters that are expiring, beginning a paced renewal of the meter population, and removing legacy phoneline meters, OHL will have reduced the number of non-standard meters to improve the efficiency of inventory management as well as reduce the risk of unexpected failures in the field. OHL utilizes smart meters for additional purposes such as monitoring transformer loading and real time outage monitoring.
Customer Value	Benefits to the customer include timely service and supply of electricity coupled with Time of Use (TOU) pricing and data visibility. Additionally, by upgrading and renewing existing meters that are expiring, this will ensure that customer meters continue functioning, capturing accurate electricity usage, and therefore enabling OHL to produce an accurate bill.
Reliability	OHL uses smart meter outage flags in its Outage Management System to monitor and analyze outages. This leads to a faster outage response and improved system reliability. In addition, continuing to maintain and renew the existing metering population ensures that the reliability of the meters themselves continues

	to be maintained, thus enabling a reliable source of billing settlement data.
Safety	New meters and installations will meet all safety standards. OHL uses real time smart meter tamper alerts to monitor and reduce unauthorized electrical work. This reduces the risk of unsafe work practices on both OHL and customer equipment.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligation* - The main driver of this program is OHL's obligation to connect new and upgraded customers as per the DSC and to maintain the meter population as per the requirements of Measurement Canada. OHL is required to ensure the meter population measures electricity accurately and reliably with each meter having an active seal. This requires purchasing and installing meters on new and upgraded services, sampling and reverify the existing meter population as per Measurement Canada, as well as pacing the renewal of the meter population to reduce the risk of failures in the field and significant lumpy future costs when meters are no longer eligible for a reasonable seal extension.

ii. Secondary Drivers: *Failure Risk* - By addressing expired meters, this reduces the risk of the meters failing and ensures the continued delivery of reliable and accurate bills.

iii. Information Used to Justify the Investment: New meter purchases are mandatory investments arising from customer requests for new service connections, therefore customer requests (i.e., future developments) are the source of information used to justify the new meter purchases. OHL also collects and tracks data on its existing meters, and this information is used to determine when a meter requires testing, resealing, or replacing.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new meters are purchased and installed to comply with the latest standards and regulations, and all metering services will be carried out in accordance with OHL's standards and practices. Meter purchases and changes due to meter seal expiry are driven through Measurement Canada requirements.

ii. Cost-Benefit Analysis: This is not applicable.

iii. Historical Investments & Outcomes Observed: The historical costs are shown in the above table. Through OHL's continued metering program, OHL continues to meet our customer's requirements for new connections, comply with the relevant regulatory requirements, and accurately measure and bill customers.

iv. Substantially Exceeding Materiality Threshold:
This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This program was created to manage the replacement of wood poles across OHL's service area. Wood poles are an integral part of the distribution system as they support the infrastructure for overhead distribution lines and are often equipped with assets such as overhead transformers, switches, and streetlights. OHL does not run poles to failure due to the potential reliability risks and safety impact if failure occurs. Wood poles are flagged for replacement based on the results of the periodic testing (non-destructive – Resitograph and visual) that assesses the condition based on remaining strength, wood rot, mechanical defects, out of plumb, and service age. OHL's most recent asset condition assessment states that 4% (67) of OHL's wood poles are in poor condition and 3% (56) are in very poor condition. This program helps to proactively plan and manage the replacement of deteriorated poles to avoid asset failures and the negative reliability and safety impacts they can cause. In addition, in the event of a complete pole failure, the reactive costs to immediately replace the failed pole are also charged to this program. OHL forecasts to replace 17 poles per year under this program. The represents approximately a 1% replacement rate.

Figure 1 - Example of a hollow decayed pole that failed pole testing.

Figure 2 - Example of a decayed pole that failed pole testing and visual inspection.

2. Timing

i. Start Date: This is an annual investment initiative to manage end-of-life assets.
ii. In-Service Date: 2024 to 2028
iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
   - Availability of labour and financial resources to accommodate higher priority or non-discretionary projects
   - Inclement weather conditions
   - Supply chain issues such as lack of availability or delayed shipments from vendors

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)					Future Costs ($ '000)					
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital	72	8	30	139	104	67	148	148	148	148	148
Contributions	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	72	8	30	139	104	67	148	148	148	148	148

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. Per unit costs for tasks such as a pole replacement are subject to significant variability from project to project due to factors such as:

- Planned Replacement vs Emergency Unplanned Replacement
- Front-lot vs Rear Lot
- Single Phase vs Three-Phase
- Single Circuit vs Double Circuit vs Triple Circuit
- Pole Sizing
- Pole Design
- Inflationary increases on material, labour, and contractors over time

Year	Quantity	Average Unit Price
2018	16	$4,486
2019	1	$5,080
2020	4	$7,345
2021	21	$6,641
2022	19	$5,482

In 2024, OHL is forecasting replacing 17 poles per year at an average replacement cost of $8,700 per pole. The unit price has been increased to account for inflationary increases on material, labour, and contractors.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 7th out of 16. The planned pole replacements are needed to reduce the quantity of deteriorated poles in the distribution system and comply with external codes/standards. Proactively identifying and replacing poles that are decayed and close to failure minimizes the risk of a failure occurring, which reduces the risk of prolonged, unexpected power outages. This aligns with the customer's need for the utility to maintain a similar level of reliability and minimize outages.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL periodically conducts field inspections of poles and uses the inspection results to update to prioritize and select the poles replacement. Some of the options that are considered when evaluating a pole replacement:

i. **Do nothing and run to failure**: OHL does consider reactive replacement for some pole replacements. While this can be employed for unplanned and unexpected failure of poles, it is not sustainable to carry out for all pole replacements. Customers would experience longer and increased unexpected outages. In addition, replacing poles reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase. In the long-term, this would increase reactive renewal costs.

ii. **Like for like replacement (proactive):** This is the standard approach when inspection and asset condition data indicates that a pole needs replacing. All poles are replaced with the latest standard design. The proposed proactive replacement of unsafe poles will ensure that the number of unplanned outages remains minimal by avoiding unexpected asset failures, so that the customers have access to reliable electricity for their needs. Costs will also be reduced when compared with completing all poles under a reactive program.

iii. **Upgrades:** If a pole has been identified as needing upgrading this is typically done with coordination with third parties, customers, road authority, and expansion developments. If these are driven by a third-party then these are carried out under System Access projects.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current OHL specifications and CSA and USF design standards and will maintain reliability. The proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. When replacing a pole, OHL inspects the attached equipment to consider replacement at the time of the new pole installation.
Customer Value	The investment will reduce the risk of future unplanned outages due to pole failures as well as reduce the risk of more expensive reactive pole replacements.
Reliability	The pole replacement program is a continuous asset replacement program to reduce the risk of unplanned outage and is required to maintain existing reliability levels.
Safety	Replacement of poles that pose a safety concern will reduce the risk of pole failures and possible downed wires. All new distribution equipment used to facilitate this project will meet or exceed the specifications in accordance with OHL, CSA standards and USF design standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Failure Risk* - The primary driver for this investment is assets at end of service life. OHL identifies poles for replacement based on testing results and takes corrective action to replace them proactively due to the potential reliability and safety impact if failure occurs. Reactive replacements also occur under this program. If a pole completely fails due to extenuating circumstances, such as during a windstorm, the costs for the like-for-like replacement are included in this program.

ii. Information Used to Justify the Investment*:* Along with its asset condition assessment, OHL uses a geospatial mapping system along with the field inspection reports (ie. resistograph test results) to identify and prioritize which poles to replace. OHL's most recent asset condition assessment states that 4% (67) of OHL's wood poles are in poor condition and 3% (56) are in very poor condition.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new installations are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. Poles with extensive serious deterioration and in critical condition are replaced immediately while others with varying degrees of degradation and remaining strength are prioritized for proactive replacement based on condition and criticality.

ii. Cost-Benefit Analysis: Running the poles to failure is an option that is considered, and some poles are addressed reactively by OHL. However, this is not a feasible option to consider for all poles, as this would result in a backlog of very poor poles that require could replacement in quantities beyond OHL's resource capacity. In addition, this would significantly reduce the reliability of the system and cause more outages to customers. Although running poles to complete failure may reduce the level of targeted capital investment in the near future, the risks associated with this alternative are not worth the cost savings due to increased safety, reliability, and system performance risks. OHL is proposing to proactively replace the identified poor and very poor condition poles on a like for like basis and upgrade them to the latest standards where they don't currently meet it.

iii. Historical Investments & Outcomes Observed: Historical costs are presented in the above table. The proactive replacement strategy of the program as planned is less costly than reactive replacements. OHL's strategy has been to sustain the system and continue to maintain reliability and continue to minimize outages. Reliability levels due to pole failure have typically been maintained. Safety from falling poles has continued to be addressed with no increase in any safety issues.

iv. Substantially Exceeding Materiality Threshold: Replacing and maintaining the condition of its poles is a continuous program. Every year, OHL assesses the number of poles that need replacement and balances this off against other priorities.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This project is a continuation of Orangeville Hydro's voltage conversion program from 4.16kV to 27.6kV. OHL's voltage conversion projects will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6 kV will result in lower line losses due to the higher operating voltage, operations and maintenance savings due to the elimination of 4.16 kV substations, enhanced public safety through the relocation of utility plant from backyards to public rights of way and the satisfaction of customer expectations for a system with high-reliability standards.

This area was selected based on asset condition assessments as well as its geographical location within the distribution system. The 4.16kV infrastructure in this area is served by MS2, which is OHL's 2nd oldest substation as well as depending on the system configuration, MS3 which is OHL's oldest substation. A portion of the underground duct and transformer foundations were installed in 2018 during a road reconstruction project. To reduce the impact on customers with excessive construction, the work was completed by the Town's contractor while the municipal streetlighting system was being replaced.

The project includes the replacement of 8 pad mounted transformers (seven single phase and one three-phase), 928 meters of primary cable, 640 meters of secondary cable, and 554 meters of directionally drilled ducts.

2. Timing

i. Start Date: Summer 2024
ii. In-Service Date: 2024
iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
   a. Availability of labour and financial resources to accommodate higher priority or non-discretionary projects
   b. Inclement weather conditions
   c. Supply chain issues such as lack of availability or delayed shipments from vendors

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	0	0	0	0	420	0	0	0	0
Contributions											
Capital (Net)	0	0	0	0	0	0	420	0	0	0	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. Per unit costs for tasks such as a transformer replacement are subject to significant variability from project to project due to factors such as:

- Polemounted vs Padmounted
- Front-lot vs Rear Lot
- Single Phase vs Three-Phase
- Transformer Sizing
- Transformer Design
- Concrete foundation replacement vs not replacing concrete foundation
- Ground grid replacement vs not replacing ground grid
- Inflationary increases on material, labour, and contractors over time

Per unit costs for tasks such as primary cable replacement are subject significant variability from project to project due to factors such as:

- Single Phase vs Three-Phase
- Primary cable voltage
- Primary cable size and material
- Primary cable design
- Installation method
- Inflationary increases on material, labour, and contractors over time

For this specific project, OHL's forecasting a unit installation cost per transformer of $18,847 and a unit installation cost per meter of primary cable of $49.

For this project, there are seven single phase pad mounted transformers where two require new ground grid and concrete foundation installations. Six of these single-phase transformers are rear-lot to front-lot conversions which are more labour intensive to complete. The one three-phase pad mounted transformer also requires a new ground grid and concrete foundation replacement. There is one section of primary cable that is three-phase while the remaining sections are single phase. The primary cable will be installed in the new directionally drilled ducts as well as duct already installed in 2018.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 15 out of 16. This is the lowest priority project within the system service category. This is a continuation of OHL's 4.16kV to 27.6kV voltage conversion program which began in the late 1980's. The 4.16kV infrastructure in this area was installed the 1970's, some of which, is older than 50 years. The majority of the subdivision was installed with rear-lot underground infrastructure which creates access issues to infrastructure for operation, maintenance, and repairs. The rear-lot primary voltage infrastructure will be relocated to front lot during this voltage conversion project.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. The existing infrastructure has reached the end of life and risk of failure as the majority of this subdivision is older than 50 years. This would impede OHL's ability to continue its now 30+ year voltage conversion program and work towards decommissioning OHL's oldest municipal substation MS2.
ii. **Carry out proposed pacing of investments:** This is the preferred option as it allows OHL to continue its long-standing voltage conversion program as well as complete a project that was previously started. Also, additional operational concerns will be resolved.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current OHL specifications and design standards to improve future life expectancy. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time. Continuation of OHL's voltage conversion projects will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16kV substations.
Customer Value	Customers will receive value from future lower line losses due to the higher operating voltage as well as the increased capacity to serve new loads as the 27.6kV infrastructure will have more capacity than the existing 4.16kV infrastructure.
Reliability	Removing non-standard legacy equipment and replacing with equipment that meets OHL's specifications and design standards assists in maintaining the existing reliability levels.
Safety	Removing non-standard legacy equipment and replacing with equipment that meets OHL's specifications and design standards improves safety for OHL's staff.

2. INVESTMENT NEED

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* System Efficiency - OHL's voltage conversion programs will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16kV substations.

ii. Secondary Drivers*:* Reliability and Capacity Upgrade – This project will replace legacy 50+ year old infrastructure that is not built to current standards and is beyond its typical useful life, in poor or very poor condition, and has challenges during replacements due to the location being in the rear-lot. From the most recent asset condition assessment for padmounted transformers, 5% (46) are in poor health with an additional 2% (64) in very poor condition. The majority of the poor and very poor padmounted transformers are on the 4.16kV system. This project is targeting the replacement of poor and very poor transformers. The capacity to serve future loads will be increased because of the higher operating voltage of the 27.6kV distribution system. This additional capacity will assist with serving new customer loads due to intensification and electrification of transportation and building heating.

iii. Information Used to Justify the Investment*:* OHL's voltage conversion program is an on-going program since the late 1980's. With only three substations remaining, the continued pacing of the voltage conversion program is required to eliminate the 4.16kV infrastructure and decommission the remaining stations. This area was selected based on asset condition assessments as well as its geographical location within the distribution system.

3. INVESTMENT JUSTIFICATION

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new replacements are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. New padmounted transformers have stainless steel enclosures to reduce risk of requiring early replacement from corrosion.

i. Cost-Benefit Analysis: OHL believes that keeping pace with the continued voltage conversion program and replacing infrastructure as per the ACA strikes a balance between risk and cost. Voltage conversion projects renew infrastructure while increasing capacity to customers, reduces future line losses, and eliminates the need for maintaining or building future municipal substations.

ii. Historical Investments & Outcomes Observed: OHL's voltage conversion program is an on-going program since the late 1980's. Since its initiation, OHL has avoided the need to build additional municipal substations and was able to decommission two existing municipal substations (MS1 & MS5) eliminating the related operating and maintenance costs. OHL's 27.6kV distribution system has been expanded to serve new customers as well as customers converted from the 4.16kV. The voltage conversion program has reduced the demand on the 44kV feeder creating capacity for new and upgrading large industrial customers to connect to the 44kV feeder. Expanding the 27.6kV also increases the capacity for new and upgrading residential, commercial, and medium-sized industrial customers to connect to the 27.6kV feeder which have more capacity than a 4.16kV feeder.

iii. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This project is a continuation of Orangeville Hydro's voltage conversion program from 4.16kV to 27.6kV. OHL's voltage conversion projects will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.kV will result in lower line losses due to the higher operating voltage, operations and maintenance savings due to the elimination of 4.16kV substations, enhanced public safety through the relocation of utility plant from backyards to public rights of way and the satisfaction of customer expectations for a system with high-reliability standards.

This area was selected based on asset condition assessments as well as its geographical location within the distribution system. The 4.16kV infrastructure in this area is served by MS2, which is OHL's 2nd oldest substation. This project was planned for and started in 2023. Due to supply chain issues, a labour resource challenges, and other competing projects, this portion of the project was deferred to 2024. The 2024 project includes the replacement of 13 single phase pad mounted transformers and 500 meters of primary cable.

In 2023, it is forecasted that 12 transformers will be completed. As of September 2023, 7 of the 12 transformers are already completed. The 2023 forecast also included the duct installation for the entire project.

2. Timing

i. Start Date: Project began in 2023 and will continue into 2024.
ii. In-Service Date: A portion of the project was in-service in 2023. The remaining portion will be in-service in 2024.
iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
    a. Availability of labour and financial resources to accommodate higher priority or non-discretionary projects
    b. Inclement weather conditions
    c. Supply chain issues such as lack of availability or delayed shipments from vendors

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	0	0	0	522	210	0	0	0	0
Contributions											
Capital (Net)	0	0	0	0	0	522	210	0	0	0	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. Per unit costs for tasks such as a transformer replacement are subject to significant variability from project to project due to factors such as:

- Polemounted vs Padmounted
- Front-lot vs Rear Lot
- Single Phase vs Three-Phase
- Transformer Sizing
- Transformer Design
- Concrete foundation replacement vs not replacing concrete foundation
- Ground grid replacement vs not replacing ground grid
- Inflationary increases on material, labour, and contractors over time

Per unit costs for tasks such as primary cable replacement are subject significant variability from project to project due to factors such as:

- Single Phase vs Three-Phase
- Primary cable voltage
- Primary cable size and material
- Primary cable design
- Installation method
- Inflationary increases on material, labour, and contractors over time

For this specific project, OHL's forecasting a unit cost per transformer of $14,240 and a unit cost per meter of primary cable of $51.

For this project, these are single phase padmounted transformers where the majority require a ground grid and concrete foundation replacement. The primary cable is single phase 28kV 2/0 with the new duct already installed in a prior year.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 8 out of 16. This is the highest priority project within the system service category. This is a continuation of OHL's 4.16kV to 27.6kV voltage conversion program which began in the late 1980's. This is also a continuation of a project that began in 2023 and is continuing into 2024. Since the project began, the electrical configuration of both the new and old infrastructure is in a non-looped state. The project is required to be finished to complete the loop on the underground system to ensure there are two sources of supply to reduce the size and duration of unplanned outages as well as future maintenance and construction activities. The conversion of the remaining portions of this subdivision will reduce the load served by OHL's 2nd oldest substation municipal substation MS2. The 4.16kV infrastructure in this area was installed the 1970's, some of which, is older than 50 years. This area also has equipment concerns when field staff are operating primary cables, such as defective capacitive test points, inoperable elbows, and access issues due to legacy non-standard equipment. Completing this voltage conversion will reduce these operational concerns.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. The existing infrastructure has reached the end of life and risk of failure as the majority of this subdivision is older than 50 years, non-standard equipment, and has been identified as in poor and very poor condition. This would impede OHL's ability to continue its now 30+ year voltage conversion program and work towards decommissioning OHL's 2nd oldest municipal substation MS2. This would also leave the existing infrastructure in-service with all the operational concerns previously mentioned.

ii. **Carry out proposed pacing of investments:** This is the preferred option as it allows OHL to continue its long standing voltage conversion program as well as complete a project that was previously started. Also, the operational concerns will be resolved.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current OHL specifications and design standards to improve future life expectancy. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time. Continuation of OHL's voltage conversion projects will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16kV substations.
Customer Value	Customers will receive value from future lower line losses due to the higher operating voltage as well as the increased capacity to serve new loads as the 27.6kV infrastructure will have more capacity than the existing 4.16kV infrastructure.

Reliability	Removing non-standard legacy equipment and replacing with equipment that meets OHL's specifications and design standards assists in maintaining the existing reliability levels.
Safety	Removing non-standard legacy equipment and replacing with equipment that meets OHL's specifications and design standards improves safety for OHL's staff. Completing project resolves the operational concerns previously mentioned which also improves safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* System Efficiency - OHL's voltage conversion programs will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16kV substations.

ii. Secondary Drivers*:* Reliability and Capacity Upgrade – This project will complete the underground loop to ensure redundant supply to the underground infrastructure. This project will replace legacy 50+ year old infrastructure that is not built to current standards, is beyond its typical useful life, is in poor and very poor condition, and has known operational concerns from field staff. From the most recent asset condition assessment for padmounted transformers, 5% (46) are in poor health with an additional 2% (64) in very poor condition. The majority of the poor and very poor padmounted transformers are on the 4.16kV system. This project is targeting the replacement of poor and very poor transformers. The capacity to serve future loads will be increased because of the higher operating voltage of the 27.6kV distribution system. This additional capacity will assist with serving new customer loads due to intensification and electrification of transportation and building heating.

iii. Information Used to Justify the Investment*:* OHL's voltage conversion program is an on-going program since the late 1980's. With only three substations remaining, the continued pacing of the voltage conversion program is required to eliminate the 4.16kV infrastructure and decommission the remaining stations. This area was selected based on asset condition assessments as well as its geographical location within the distribution system.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new replacements are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. New padmounted transformers have stainless steel enclosures to reduce risk of requiring early replacement from corrosion.

i. Cost-Benefit Analysis: OHL believes that keeping pace with the continued voltage conversion program and replacing infrastructure as per the ACA strikes a balance between risk and cost. Voltage conversion projects renew infrastructure while increasing capacity to customers, reduces future line losses, and eliminates the need for maintaining or building future municipal substations.

ii. Historical Investments & Outcomes Observed: OHL's voltage conversion program is an on-going program since the late 1980's. Since its initiation, OHL has avoided the need to build additional municipal substations and was able to decommission two existing municipal substations (MS1 & MS5) eliminating operating and maintenance costs. OHL's 27.6kV distribution system has been expanded to serve new customers as well as customers converted from the 4.16kV. The voltage conversion program has reduced the demand on the 44kV feeder creating capacity for new and upgrading large industrial customers to connect to the 44kV feeder. Expanding the 27.6kV also increases the capacity for new and upgrading residential, commercial, and medium-sized industrial customers to connect to the 27.6kV feeder which have more capacity than a 4.16kV feeder.

iii. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad *meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.*

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This project is a continuation of Orangeville Hydro's voltage conversion program from 4.16kV to 27.6kV. OHL's voltage conversion projects will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6 kV will result in lower line losses due to the higher operating voltage, operations, and maintenance savings due to the elimination of 4.16 kV substations, enhanced public safety through the relocation of utility plant from backyards to public rights of way and the satisfaction of customer expectations for a system with high-reliability standards.

The timing and boundaries of this project are being driven by a municipal road reconstruction project. In March 2023, the Town of Orangeville and their Engineering Consultant reached out to OHL to inform us of the project as well as determine OHL's needs while the road is under construction. While this area was targeted for conversion in 2025 as part of a larger project, this specific area will be completed one year earlier to join the Town's reconstruction project. By joining Town's project, OHL will be able to reduce the amount of construction activity within this subdivision, benefit from utilizing open trench duct and road crossing installation instead of the more expensive directional drilling and reduce restoration costs that would exist if OHL was completing the project alone.

The 4.16kV infrastructure in this area is served by a 16kV-2.4kV step-down transformer. The 4.16kV/2.4kV infrastructure is located on rear-lot overhead pole lines that are owned by Bell Canada. This scope of this project is to bring overhead primary voltage infrastructure (overhead conductor and pole mounted transformer) off the Bell Canada poles to the front public right of way while converting it to 27.6kV and underground (underground primary cable in duct and pad mounted transformers). The existing secondary services will remain in place.

The project includes the installation of 4 single phase pad mounted transformers (three requiring concrete foundations with ground grids), 425 meters of primary cable, 412 meters of secondary cable, 440 meters of open trench duct, and 151 meters of directionally drilled ducts.

2. Timing

i. Start Date: Expected Summer 2024, timing is dependent on municipality
ii. In-Service Date: 2024

iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
   a. Since this is a municipally-led project, the timing will be driven by the Town's contractors construction schedule
   b. Availability of labour and financial resources to accommodate higher priority or non-discretionary projects
   c. Inclement weather conditions
   d. Supply chain issues such as lack of availability or delayed shipments from vendors

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	0	0	0	0	0	0	189	0	0	0	0
Contributions											
Capital (Net)	0	0	0	0	0	0	189	0	0	0	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

This is not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. Per unit costs for tasks such as a transformer replacement are subject to significant variability from project to project due to factors such as:

- Polemounted vs Padmounted
- Front-lot vs Rear Lot
- Single Phase vs Three-Phase
- Transformer Sizing
- Transformer Design
- Concrete foundation replacement vs not replacing concrete foundation
- Ground grid replacement vs not replacing ground grid
- Inflationary increases on material, labour, and contractors over time

Per unit costs for tasks such as primary cable replacement are subject significant variability from project to project due to factors such as:

- Single Phase vs Three-Phase
- Primary cable voltage

- Primary cable size and material
- Primary cable design
- Installation method
- Inflationary increases on material, labour, and contractors over time

For this specific project, OHL's forecasting a unit installation cost per transformer of $12,615 and a unit installation cost per meter of primary cable of $48.

For this project, there are 4 single phase pad mounted transformers where 3 require new ground grid and concrete foundation installations. 3 of these single-phase transformers are rear-lot to front-lot conversions which are more labour intensive to complete. The primary cable is 28kV 2/0 Aluminum. The primary cable will be installed in the open trench installed duct. The secondary cable will be installed in the directionally drilled installed duct.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 10 out of 16. This is the middle priority project within the system service category. This is a continuation of OHL's 4.16kV to 27.6kV voltage conversion program which began in the late 1980's.

The 4.16kV infrastructure in this area was installed the late 1960's. The subdivision was installed with rear-lot overhead infrastructure which creates access issues to infrastructure for operation, maintenance, and repairs. The rear-lot overhead primary conductor also creates challenges with vegetation management as OHL's trucks are unable to access the infrastructure, therefore, an arborist contractor is required to complete the rear-lot line clearing activities. The rear-lot primary voltage infrastructure will be relocated to front lot during this voltage conversion project.

If this project is not complete, there will be a missed opportunity to coordinate with the municipality.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. The existing infrastructure has reached the end of life and risk of failure as this subdivision was built in the late 1960's. This would impede OHL's ability to continue its now 30+ year voltage conversion program. This would also miss the opportunity to coordinate this installation with the municipality.

ii. **Partial Project:** There is the option of only installing the portion of the infrastructure the benefits from the joint project with the Town. The transformer foundations, ground grid, and open trench ducts could be installed and then the project paused. This option would lose the following benefits:
   - Customers would have to endure the municipal road reconstruction in 2024 and then the OHL remaining construction project shortly afterwards. In prior plans, this area was targeted for 2025.
   - OHL would be responsible to surface restorations for any sidewalks, driveways, or yards that are disturbed while completing the remaining work.
   - OHL has already worked with existing property owners on access requirements and details for any work on private property. It is preferred to complete the work while these property owners still own the property which we require access and will install infrastructure on.

   Based on the above, this is not the preferred option.

iii. **Carry out investments in 2024:** This is the preferred option as it allows OHL to continue its long-standing voltage conversion program as well as fully obtain the benefits of a project that is coordinated with a third party such as the municipality.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current OHL specifications and design standards to improve future life expectancy. Line clearing costs will be reduced. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time. Continuation of OHL's voltage conversion projects will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16kV substations. By coordinating with the municipal project, there is the opportunity to install open trench duct which is less expensive that directionally drilling when done with a municipal road reconstruction.
Customer Value	Customers will receive value from future lower line losses due to the higher operating voltage as well as the increased capacity to serve new loads as the 27.6kV infrastructure will have more capacity than the existing 4.16kV infrastructure. The local customers will benefit from having the overhead primary conductor and transformers removed from their backyards.
Reliability	Removing non-standard legacy equipment and replacing with equipment that meets OHL's specifications and design standards assists in maintaining the existing reliability levels. Removing the rear-lot primary conductor and transformers removes the risk of power outage during storms from tree contacts and tree failures. Both of which have occurred in this area.
Safety	Removing non-standard legacy equipment and replacing with equipment that meets OHL's specifications and design standards improves safety for OHL's staff. Removing the rear-lot primary conductor removes the risks of fires from trees contacting electrical infrastructure and removes the risk of electrical contact when children are climbing trees.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* System Efficiency - OHL's voltage conversion programs will allow OHL to become a station-less system, whilst continuing to maintain its reliability. This conversion to 27.6kV will result in lower line losses due to the higher operating voltage, operations and maintenance saving due to the elimination of 4.16kV substations.

ii. Secondary Drivers*:* Reliability and Capacity Upgrade – This project will replace legacy 50+ year old infrastructure that is not built to current standards, is beyond its typical useful life, has been identified as in poor or very poor condition, and has challenges during replacements and maintenance due to the location being in the rear-lot. From the most recent asset condition assessment for polemounted transformers, 24% (83) are in poor health with and additionally 10% (33) in very poor health. This project is targeting the replacement of poor and very poor pole mounted transformers. The capacity to serve future loads will be increased because of the higher operating voltage of the 27.6kV distribution system. This additional capacity will assist with serving new customer loads due to intensification and electrification of transportation and building heating.

iii. Information Used to Justify the Investment*:* remaining, the continued pacing of the voltage conversion program is required to eliminate the 4.16kV infrastructure and decommission the remaining stations. This area was selected based on asset condition assessments as well as its geographical location within the distribution system. The timing of this project is based on coordinating with the municipality to achieve costs savings as well as to reduce the impact on customers from multiple years of construction activity in their neighborhood.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: All new replacements are in compliance with Utility Standards Forum (USF) standards and installed using safe work practices. New padmounted transformers have stainless steel enclosures to reduce risk of requiring early replacement from corrosion.

i. Cost-Benefit Analysis: OHL believes that keeping pace with the continued voltage conversion program and replacing infrastructure as per the ACA strikes a balance between risk and cost. Voltage conversion projects renew infrastructure while increasing capacity to customers, reduces future line losses, and eliminates the need for maintaining or building future municipal substations.

ii. Historical Investments & Outcomes Observed: OHL's voltage conversion program is an on-going program since the late 1980's. Since its initiation, OHL has avoided the need to build additional municipal substations and was able to decommission two existing municipal substations (MS1 & MS5) reducing operating and maintenance costs. OHL's 27.6kV distribution system has been expanded to serve new customers as well as customers converted from the 4.16kV. The voltage conversion program has reduced the demand on the 44kV feeder creating capacity for new and upgrading large industrial customers to connect to the 44kV feeder. Expanding the 27.6kV also increases the capacity for new and upgrading residential, commercial, and medium-sized industrial customers to connect to the 27.6kV feeder which have more capacity than a 4.16kV feeder.

iii. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

OHL owns and maintains nine vehicles, five trailers, and a forklift within its fleet. OHL's fleet is listed below. All the equipment is owned by OHL with no vehicles under a lease agreement.

Truck #	Size	Model Year	Description	In Service Year
-	-	1997	Nissan Forklift	2001
-	Trailer	2011	Pole Trailer	2011
-	Trailer	2011	Equipment Trailer	2011
-	Trailer	1998	Reel Trailer	1998
-	Trailer	2014	Reel Trailer – Hydraulic Lift	2014
-	Trailer	2014	Vermeer Wood Chipper	2014
24	Large	2007	Posi-Plus/Freightliner Double Bucket	2006
33	Large	2015	Altec/Freightliner Digger/Derick	2014
34	Small	2014	GMC 1500 Sierra Crew Cab	2015
35	Medium	2015	GMC 3500 HD Dump Truck	2016
36	Small	2015	GMC 1500 Sierra Crew Cab	2016
37	Small	2015	GMC 1500 Sierra Crew Cab	2017
38	Large	2018	Posi-Plus/Freightliner Single Bucket	2018
39	Small	2019	Kia Soul EV	2019
40	Large	2020	Altec/Ford F550 Single Bucket	2020

Fleet vehicles must be maintained to ensure public and employee safety, to comply with legal requirements, and to ensure operational capability when staff require them for distribution system maintenance activities, construction activities, and outage response. When replacing vehicles, OHL considers the following criteria: Vehicle age, mileage, engine and PTO hours, annual maintenance/inspection results, repair history, and use case requirements.

In 2024, OHL is forecasting replacing a light pickup truck (a GMC 1500 Sierra Crew Cab) with a new all-electric Ford Lightning pickup truck. The new all-electric pickup truck will be used for transporting staff and material for operation, maintenance, and capital construction programs similar to the use of existing pickup trucks. Purchasing an all-electric pickup truck will reduce OHL's GHG emissions, reduce gasoline fuel requirements, and remove the need for periodic maintenance activities such as oil changes.

The vehicle replacements planned within the forecast period are:

2025 – Replacement of a GMC Sierra 1500 Crew Cab with a new Crew Cab pickup truck

2026 – Replacement of a GMC Sierra 1500 Crew Cab with a new all-electric pickup truck

2027 – Replacement of Truck #24 2007 Posi-Plus/Freightliner Double Bucket Truck with a new Double Bucket Truck

2028 – Replacement of Truck #35 2015 GMC 3500 HD Dump Truck with a new Dump Truck

2. Timing

i. Start Date: January 2024
ii. In-Service Date: 2024 through to 2028
iii. Key factors that may affect timing: Factors that may impact timing include supply chain constraints, availability of equipment, and unexpected failures.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	293	33	181	0	0	0	94	70	100	395	100
Contributions											
Capital (Net)	293	33	181	0	0	0	94	70	100	395	100

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The historical costs in 2018 were for:

- The purchase of #38 – 2018 Posi-Plus/Freightliner Single Bucket

The historical costs for 2019 were for:

- The purchase of #39 – 2019 Kia Soul EV

The historical costs for 2020 were for:

- The purchase of #40 – 2020 Altec/Ford F550 Single Bucket

There were no vehicle purchases in 2021 & 2022.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 13 out of 16. OHL's vehicle strategy plans for small vehicles, such as pickup trucks, to remain in service for 8 years. As of 2023, OHL's three pickup trucks have been in service for 8 years (#34), 7 years (#36), and 6 year (#37). OHL plans to replace one pickup truck per year in 2024, 2025, and 2026. OHL plans to replace its Double Bucket Truck (#24) in 2027 after 20 years of service. OHL plans to replace its Dump Truck (#35) after 12 years of service. Continued investments in OHL's fleet over the forecast period is needed to continue supporting business needs. Without proper fleet management, proactive and reactive work can fall behind thus increasing risks to safety and reliability and increasing costs.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. Continued investments in OHL's fleet over the forecast period is needed to continue supporting business needs. Without proper fleet management, proactive and reactive work can fall behind thus increasing risks to safety and reliability and increasing costs.

ii. **Like-for-Like Replacement:** OHL considered replacing the GMC 1500 Sierra pickup truck with a similar gasoline powered pickup truck. The issues found with these options were:
   - No reduction OHL's GHG emissions
   - No progression with OHLs electrification of transportation
   - No reduction in gasoline fuel usage
   - Continued requirement for periodic maintenance such as oil changes

iii. **Purchase of an all-electric pickup truck:** This is the preferred option for OHL. Purchasing an all-electric pickup truck will reduce OHL's GHG emissions, reduce gasoline fuel requirements, and remove the need for periodic maintenance activities such as oil changes.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Consistent management of OHL's fleet will ensure that life cycle costs and risks of catastrophic failure remain low. Planned replacement of the fleet ensures that OHL staff are using the most efficient and reliable equipment possible while on the job. Unreliable fleet can negatively impact utility performance, such as reliability and employee productivity, and as vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs.

Customer Value	The replacement of end-of-life fleet vehicles will allow OHL to maintain its ability to provide a timely, safe, and reliable service to customers. Having a safe and reliable fleet reduces operating and maintenance costs and mitigates the risk of work disruption and delays in customer service requests and/or outage response time to unplanned incidents, such as trouble calls and storm response, due to vehicle breakdown. The planned replacement of old and unreliable fleet also mitigates any catastrophic failure which may threaten the safety of employees and the public.
Reliability	The replacement of end-of-life fleet vehicles allows for the continued efficient day to day operations of the OHL business. Having reliable vehicles is important to the delivery of reliable electricity to customers as outages are not unnecessarily prolonged due to vehicle breakdown when replacing the distribution equipment.
Safety	Planned replacement of fleet mitigates any catastrophic failure which may threaten the safety of employees and the public.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* Failure Risk - The main driver for this program is addressing the risk of failure of assets that are at end of typical useful life and operational effectiveness. All fleet vehicles are needed to support business needs, and over time, these units are subject to wear and tear that can impact vehicle safety, reliability, and operational efficiency. As vehicles age and mileage increases, they also incur higher operating expenses due to increasing levels of reactive repairs. Continued investments in OHL's fleet over the forecast period is needed to continue supporting business needs.

i. Secondary Drivers: Maintenance and Capital Investment Support – Investments into fleet vehicle replacements when vehicles reach end of typical useful life is essential to ensure that OHL continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities.

ii. Information Used to Justify the Investment: OHL's vehicle replacement strategy is to replace small vehicles (pickup trucks) after 8 years of service, medium vehicles after 12 years of service, and large vehicles after 15 years of service. When replacing vehicles, OHL considers the following criteria: Vehicle age, mileage, engine and PTO hours, annual maintenance/inspection results, repair history, and use case requirements. The forecasted costs for 2025 - 2028 were based on historical purchase prices. The forecasted cost for the 2024 purchase was based on estimates from a dealership.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: Replacing end-of-life vehicles is an industry standard practiced by all utilities within Ontario. In order to maintain the distribution system, it is critical that OHL's fleet vehicles are reliable. Reliable fleet vehicles help OHL achieve reliability targets by enabling crews to respond to outages in a timely manner. In addition, reliable fleets help OHL staff complete the require operation, maintenance, and capital construction programs and projects. Regulations such as the Highway Traffic Act set out rules and requirements for all commercial vehicles. OHL must ensure its vehicles comply with this act through maintenance of existing vehicles and through this vehicle replacement program.

ii. Cost-Benefit Analysis: Ongoing fleet vehicle maintenance is needed to ensure that OHL staff continue to have access to safe and reliable fleet vehicles needed to support business needs. When it comes to replacing an existing end of life fleet vehicle alternatives are evaluated on a case-by-case basis, quotes are obtained from manufacturers or dealerships, and cost analysis is considered.

i. Historical Investments & Outcomes Observed: OHL's historical investments for this program were described in Section 5. Historical investments in this program have resulted in the ability for OHL staff to have access to safe and reliable vehicles to support their job functions. This has ensured OHL's continued ability to serve customers day to day and deliver safe and reliable electricity to our customers.

ii. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

i. This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

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The vehicle replacements planned within the forecast period are:

2025 – Replacement of a GMC Sierra 1500 Crew Cab with a new Crew Cab pickup truck

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2. Timing

i. Start Date: January 2024
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7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. Continued investments in OHL's fleet over the forecast period is needed to continue supporting business needs. Without proper fleet management, proactive and reactive work can fall behind thus increasing risks to safety and reliability and increasing costs.

ii. **Like-for-Like Replacement:** OHL considered replacing the GMC 1500 Sierra pickup truck with a similar gasoline powered pickup truck. The issues found with these options were:
   - No reduction OHL's GHG emissions
   - No progression with OHLs electrification of transportation
   - No reduction in gasoline fuel usage
   - Continued requirement for periodic maintenance such as oil changes

iii. **Purchase of an all-electric pickup truck:** This is the preferred option for OHL. Purchasing an all-electric pickup truck will reduce OHL's GHG emissions, reduce gasoline fuel requirements, and remove the need for periodic maintenance activities such as oil changes.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

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Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Consistent management of OHL's fleet will ensure that life cycle costs and risks of catastrophic failure remain low. Planned replacement of the fleet ensures that OHL staff are using the most efficient and reliable equipment possible while on the job. Unreliable fleet can negatively impact utility performance, such as reliability and employee productivity, and as vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs.

Customer Value	The replacement of end-of-life fleet vehicles will allow OHL to maintain its ability to provide a timely, safe, and reliable service to customers. Having a safe and reliable fleet reduces operating and maintenance costs and mitigates the risk of work disruption and delays in customer service requests and/or outage response time to unplanned incidents, such as trouble calls and storm response, due to vehicle breakdown. The planned replacement of old and unreliable fleet also mitigates any catastrophic failure which may threaten the safety of employees and the public.
Reliability	The replacement of end-of-life fleet vehicles allows for the continued efficient day to day operations of the OHL business. Having reliable vehicles is important to the delivery of reliable electricity to customers as outages are not unnecessarily prolonged due to vehicle breakdown when replacing the distribution equipment.
Safety	Planned replacement of fleet mitigates any catastrophic failure which may threaten the safety of employees and the public.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*:* Failure Risk - The main driver for this program is addressing the risk of failure of assets that are at end of typical useful life and operational effectiveness. All fleet vehicles are needed to support business needs, and over time, these units are subject to wear and tear that can impact vehicle safety, reliability, and operational efficiency. As vehicles age and mileage increases, they also incur higher operating expenses due to increasing levels of reactive repairs. Continued investments in OHL's fleet over the forecast period is needed to continue supporting business needs.

i. Secondary Drivers: Maintenance and Capital Investment Support – Investments into fleet vehicle replacements when vehicles reach end of typical useful life is essential to ensure that OHL continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities.

ii. Information Used to Justify the Investment: OHL's vehicle replacement strategy is to replace small vehicles (pickup trucks) after 8 years of service, medium vehicles after 12 years of service, and large vehicles after 15 years of service. When replacing vehicles, OHL considers the following criteria: Vehicle age, mileage, engine and PTO hours, annual maintenance/inspection results, repair history, and use case requirements. The forecasted costs for 2025 - 2028 were based on historical purchase prices. The forecasted cost for the 2024 purchase was based on estimates from a dealership.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: Replacing end-of-life vehicles is an industry standard practiced by all utilities within Ontario. In order to maintain the distribution system, it is critical that OHL's fleet vehicles are reliable. Reliable fleet vehicles help OHL achieve reliability targets by enabling crews to respond to outages in a timely manner. In addition, reliable fleets help OHL staff complete the require operation, maintenance, and capital construction programs and projects. Regulations such as the Highway Traffic Act set out rules and requirements for all commercial vehicles. OHL must ensure its vehicles comply with this act through maintenance of existing vehicles and through this vehicle replacement program.

ii. Cost-Benefit Analysis: Ongoing fleet vehicle maintenance is needed to ensure that OHL staff continue to have access to safe and reliable fleet vehicles needed to support business needs. When it comes to replacing an existing end of life fleet vehicle alternatives are evaluated on a case-by-case basis, quotes are obtained from manufacturers or dealerships, and cost analysis is considered.

i. Historical Investments & Outcomes Observed: OHL's historical investments for this program were described in Section 5. Historical investments in this program have resulted in the ability for OHL staff to have access to safe and reliable vehicles to support their job functions. This has ensured OHL's continued ability to serve customers day to day and deliver safe and reliable electricity to our customers.

ii. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

i. This is not applicable.

A. General Information on the Project/Program

A distributor needs to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing), total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable), comparative historical expenditures, investment priority, alternatives considered, and the cost benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

This capital program is comprised of OHL's ongoing business requirement to add and/or upgrade end user software. End-user software are internal applications that support OHL operations. Computer software supports multiple functions within OHL to allow the distributor to provide reliable and safe power to its customers, meet regulatory requirements, and communicate effectively with our customers. IT software includes Customer Information Systems (CIS), the customer portal, the Geospatial Information System (GIS), security applications, finance support, the internal OHL intranet, and financial systems.

For 2024, OHL forecasts the following expenses within the Computer Software program:

Transition to New GIS: OHL plans to transition from Autodesk AutoCAD Map 3D GIS to a comprehensive ESRI GIS (ESRI). The GIS is used to track individual pieces of equipment in the field, as well as customer and loading data geographically. All physical changes to the distribution system are captured in GIS on an ongoing basis. Documentation of inspection records is facilitated through the use of a mobile field mapping and data collection software application. OHL's existing GIS has limited functionality requiring OHL to utilize multiple software applications instead of relying on one database. This creates versioning issues with data disaggregation. Moving to the industry standard of ESRI will allow OHL to share and integrate data subsets with other third parties such as customers, municipalities, road authorities, locate service providers, Infrastructure Ontario, and dedicated locators. The ESRI system will also be the foundation for an updated and improved customer facing outage mapping system. The ESRI GIS is expected to improve asset record accuracy, assist with asset condition assessments, reduce repeat field visits, assist with pre-engineering design work, and allow for increase analytics of asset information for future Distribution System Plans, asset condition assessments, and distribution maintenance programs. The forecasted cost for 2024 is $90,380.

Great Plains Upgrade: OHL utilizes Microsoft Dynamics Great Plains ("Great Plains") as its financial software. An upgrade is required every three years, to update all areas of the software. The purpose of the upgrade is to take advantage of current technologies, as well as utilize the current version's new features and functionality. OHL utilizes Great Plains with many modules, specifically General Ledger, Accounts Payable, Accounts Receivable, Payroll, Fixed Assets, Work Orders, Inventory, Receiving, and Job Costing.

Every time an upgrade takes place, Great Plains provides a list of new functionalities that can be used. An upgrade will typically fix any identified issues within the system, as well as incorporate any feature changes requested by Great Plains customers and update its cyber security features to improve security as needed. OHL contracts out the implementation of the upgrade to its Great Plains support vendor. The forecasted cost for 2024 is $30,000.

CIS Alterations, Additions, and Updates: NorthStar CIS/billing

Harris Northstar is a commonly used CIS/billing system in the Ontario electric utility industry. It has evolved over the last forty-plus years through continual enhancements and modifications to include all aspects of billing and customer service. The CIS/billing system provides a single solution for tracking all interactions with customers including consumption history, billing history, adjustments, credit history, meter inventory, premise and meter history, service order history, and more. The Harris CIS/billing system is extremely flexible and provides a high degree of integration with all the major handheld units. This integration also extends to integrating with other applications such as third-party accounting systems, external bill print organizations, credit bureaus, interactive voice response systems, and document management solutions.

Orangeville Hydro utilizes NorthStar Customer Service Information System "CIS" as our billing system. CIS software is the backbone of all customer data and is used for billing electricity, billing water and collections. Enhancements and upgrades are required to maintain productivity and to benefit from new software capabilities as well as comply with regulatory changes in the sector.

Customer Facing Portal: OHL provides a customer portal to its customers. The customer portal provides 24/7 access to:

- View electricity consumption patterns on an hourly, daily, or monthly basis
- View account balance and payment history
- Receive, view and download paperless bills
- Receive high usage alerts
- Download historical usage information

OHL's legacy customer portal is called Customer Connect. The vendor no longer supports this product. This means the products is not receiving feature improvements, and more importantly, the products is no longer receiving critical cybersecurity improvements and patching. OHL, along with a group of other LDCs, plans to transition to a new customer portal called Silverblaze.

Silverblaze is:

- Commonly used by other LDCs in Ontario
- Fully supported and receiving required updates and patches
- Provides existing functions and features to our customers as the existing portal

- Provides additional functionality such as advanced move-in & move-out functionality, smart forms, usage analytics, notification & alerts, improved self-serve functionality, two-way outage communication, and improved payment capabilities.

The forecasted cost for 2024 is $45,000.

2. Timing

i. Start Date: 2024
ii. In-Service Date:2024
iii. Key factors that may affect timing: OHL considers several factors that could impact the timing of this program:
   - Availability of financial resources to accommodate higher priority or non-discretionary projects delays from third party providers.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Future Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Capital (Gross)	22	49	21	23	26	15	197	107	32	32	32
Contributions											
Capital (Net)	22	49	21	23	26	15	197	107	32	32	32

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The historical costs in 2018 were for:

- iDrive/BMR Storage Upgrade
- Password management software licences
- Upgrades to paperless data management system

The historical costs for 2019 were for:

- RSVA Risk Manager Implementation
- Licences and setups for new Windows devices
- Implementation and Setup for KUBRA Integration (print, stuff, mail vendor)
- Filenexus Server Upgrades

The historical costs for 2020 were for:

- CIS update for Customer Choice (TOU-Opt Out)
- RSVA Risk Manager integration with Operational Data Storage
- Microsoft Office 365 Upgrades

The historical costs for 2021 were for:

- Great Plains periodic update and implementation including virtual server

The historical costs for 2022 were for:

- Financial software upgrade for paystub encryption
- GIS update and hosted server change
- Metering management software upgrade
- New website development

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using the prioritization process outlined in section 5.3.1 in the DSP, this project has a priority ranking of 12 out of 16. This is the 3rd highest ranking within the General Plant category. Prioritization for the selected assets is based on specific business needs for each project. Investment in this program ensure that the upgrades keep up with the technology trends and cyber security requirements. These investments will allow OHL to maintain robust IT systems and cyber security protocols which ultimately contribute to overall reliability.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

OHL considered the following options:

i. **Do Nothing:** Doing nothing is not a viable option. Doing nothing subjects OHL to a risk of cybersecurity incidents and having unsupported obsolete software which would ultimately impact company operations and disaster recovery.

ii. **Like-for-Like Replacement:** OHL has to regularly upgrade IT software.

iii. **Carry out the proposed pacing of investments:** This is the preferred option for OHL. This option allows OHL to implement more viable redundancies for disaster recovery. This option also entails upgrading of network infrastructure to replace outdated software to ensure continued reliability while also replacing outdated software to improve cyber security and overall security.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

This is not applicable.

9. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Software is treated as a strategic asset. The Customer information System (CIS) software is the backbone of all customer data and is used for billing electricity. Enhancements and upgrades are required to maintain productivity and to benefit from new software capabilities. Automation software is implemented to streamline existing and new processes allowing better productivity and customer service. Network security is also a high priority; software upgrades and additions play an important role in maintaining data integrity, security, and privacy.
Customer Value	OHL's ability to provide services to its customers relies heavily on Information Technology (IT) with software and a customer portal being critical components. Maintaining adequate software provides the corporation and staff the tools to provide timely services to customers. Self-serve customer portals, green button solutions and digital services provide value and convenience to OHL customers. Security software, as required, is integral in maintaining cyber security and privacy requirements.

Reliability	Maintaining robust IT systems will contribute to reliability.
Safety	Maintaining IT software is crucial to the safety of the public and employees. Continued improvements to these systems are prudent in maintaining safety through the use of remote administration and visibility of the distribution systems.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: Operational effectiveness and efficiency. By upgrading its IT network software, OHL will be able to carry out its operations as efficiently and safely as possible, catering to customer expectations. OHL ensures that cost controls are in place to limit rate increases on ratepayers.
ii. Secondary Drivers: New technology and cyber security. Remaining up to date with new technologies and cyber security requirements is critical for OHL to maintain safe and reliable hardware for staff and contractors to perform their jobs competently.
iii. Information Used to Justify the Investment: OHL's software refresh policy is for a 5-year refresh. OHL tracks software to facilitate replacement as required to meet the lifecycle. OHL monitors and tracks the latest cyber security requirements and vendor software upgrades and identifies investments required to enable it to comply with these requirements in a timely manner.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: OHL adheres to an IT software industry standard practice of managing its software on a 5-year lifecycle to ensure vendor support is available, decrease the likelihood of failure, meet business needs and ensure cyber security threats are mitigated.
ii. Cost-Benefit Analysis: A cost benefit analysis is considered for all IT projects.
iii. Historical Investments & Outcomes Observed: Historical costs for software solutions are variable depending on the solution but have increased over time.
iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

i. This is not applicable.

Appendix F – OHL's REG Investment Plan

ORANGEVILLE HYDRO LIMITED

Renewable Energy Generation Investments Plan

Prepared for the

Independent Electricity System Operator

To accompany

Orangeville Hydro Ltd.'s
2024 COS Application

June 2023

TABLE OF CONTENTS

1 INTRODUCTION

In accordance with the Ontario Energy Board ("**OEB**") *Filing Requirements for Electricity Transmission and Distribution Applications*, Orangeville Hydro Limited ("**OHL**") 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 OHL'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 (2024-2028) and to request the IESO to provide a letter commenting on this information.

Section 2 of this REG Investments Plan provides background information regarding OHL'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 ORANGEVILLE HYDRO'S DISTRIBUTION GRID

OHL is the local distribution company, responsible for electricity distribution in the Town of Orangeville and the Town of Grand Valley. OHL's distribution network serves a population approximately 30,000 and approximately 12,900 customers. The service area served by OHL covers 17 square kilometers.

OHL receives power form Hydro One at the following Hydro One owned stations:

- Orangeville TS
- Grand Valley DS

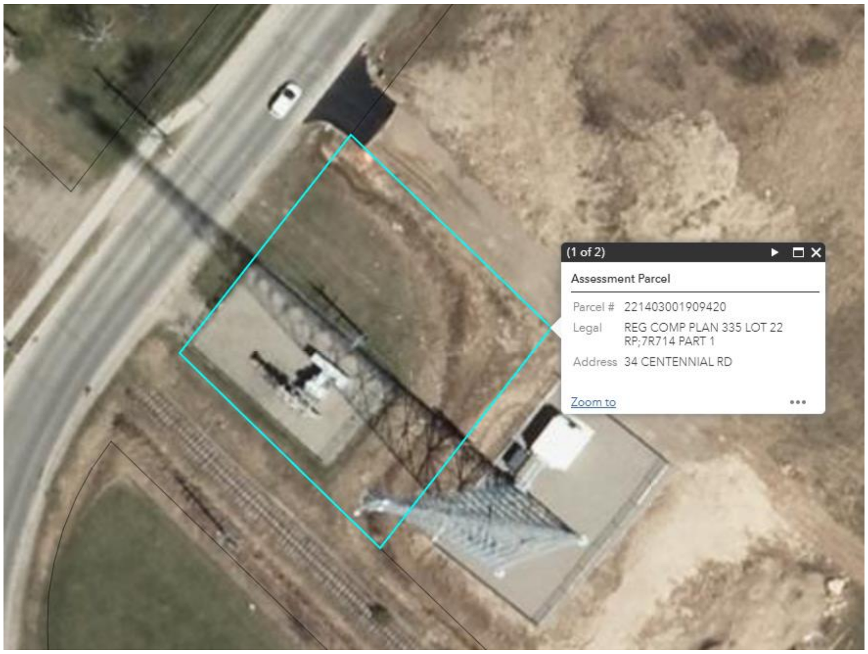
There are four sub-transmission feeders for the Town of Orangeville, two dedicated to OHL and two shared with Hydro One, that supply a total of three Municipal Distribution Stations ("**MS")**, where power is stepped down to 4.16 kV.

Grand Valley is fed from one sub-transmission feeder that is connected to the Hydro One owned Grand Valley DS, which is fed from a HONI owned 44kV feeder.

Figure 1 indicates the MS locations within the OHL service territory and as shown, these MS locations provide good coverage within the entire service territory for renewable energy generation plant connections. Table 1 shows the rated capacities and the peak load served from each MS in 2022.

Figure 1 – OHL Orangeville MS locations

MS2:



MS3:

MS4:

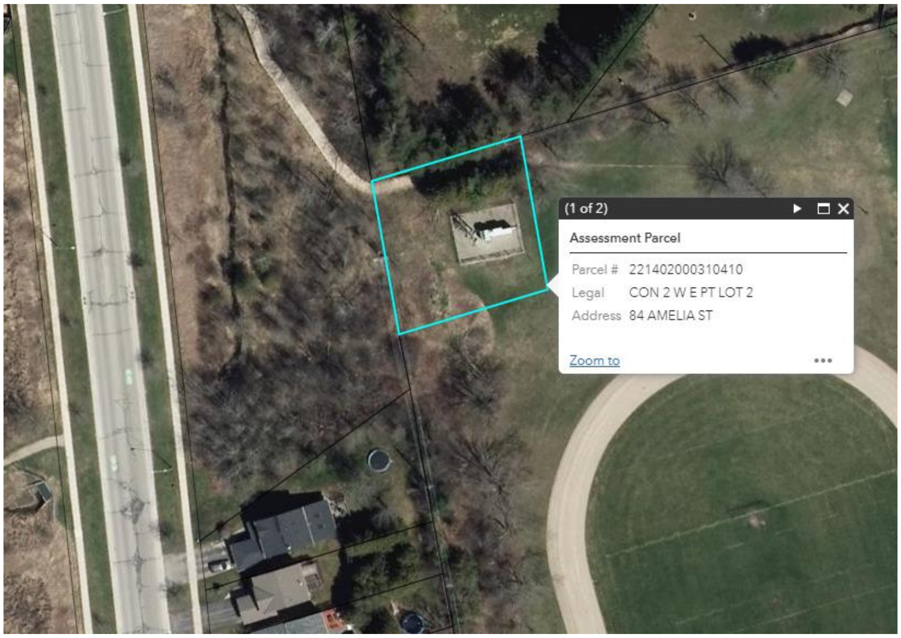


Figure 2 – HONI Grand Valley DS location

Hydro One Owned & Operated Grand Valley DS:

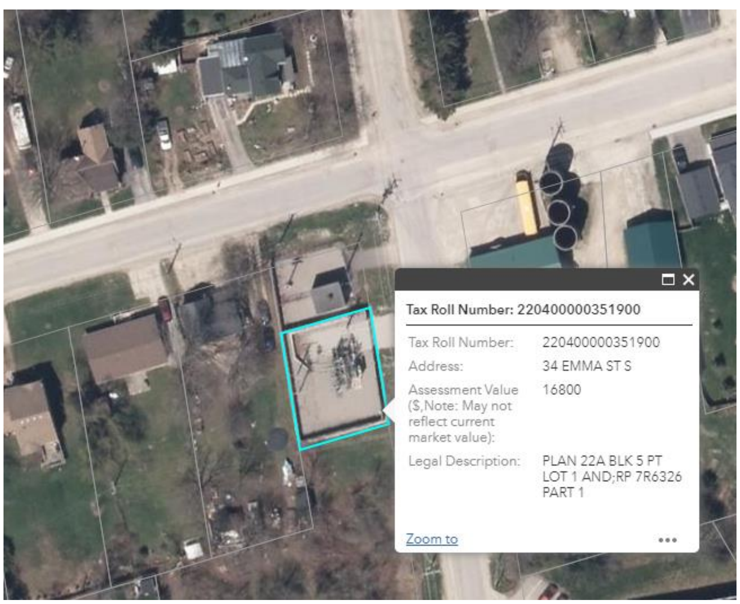


Table 1 – Municipal Distribution Station Capacities and Loads

Distribution Station (4.16 kV)	MVA Rating ONAN	2022 Peak Load (MW)
MS2	5	1.8
MS3	5	1.8
MS4	5	1.2

Table 2 – Feeder Peak Loads

Feeder	2022 Peak Load (MW)
GV-F2 Feeder	3.1
M5 Feeder	14.1
M23 Feeder	13.0
M25 Feeder	9.2
M26 Feeder	14.6

3 EXISTING AND PROPOSED CONNECTIONS

There are a total of 46 renewable energy generation installations presently connected to OHL's distribution system under the province's Feed-in-Tariff ("**FIT**") and microFIT programs, as summarized below and detailed in Table 2 and Table 3, respectively. In summary, the breakdown of these connections with the total contract nameplate capacity are:

- 8 FIT installations with generating capacity of 1,665 kW, listed in Table 2
- 34 microFIT installations with 266 kW installed capacity, as shown in Table 3
- 4 solar net-metering installations with 101 kW installed capacity.
- 1 wind net-metering installations with 2 kW installed capacity.

OHL is providing the last five-year statistics of net-metering services connected to the distribution system in Table 4. Approximately zero to one new net-metering services have been installed each year. Hence, OHL projects to connect similar to historical levels of new net-metering service a year over the 2023-2028 forecast period.

Table 2 – Existing FIT Generation Facilities

S. No.	Fuel Source	kW Rating (Contract Capacity)
F04-250	Photovoltaic	250kW
F19-250	Photovoltaic	250kW
F25-075	Photovoltaic	75kW
F27-050	Photovoltaic	50kW
F28-130	Photovoltaic	130kW
F41-300	Photovoltaic	300kW
F48-400	Photovoltaic	480kW
F47-130	Photovoltaic	130kW
Total		**1665kW**

Table 3 – Existing MicroFIT Generation Facilities

Micro-FIT Reference #	Meter Install Date	kW Rating (Contract Capacity)
F00-010	Photovoltaic	9.9kW
F02-002	Photovoltaic	2.1kW
F03-005	Photovoltaic	4.56kW
F05-010	Photovoltaic	10kW
F10-003	Photovoltaic	3kW
F12-010	Photovoltaic	10kW
F13-010	Photovoltaic	10kW
F14-010	Photovoltaic	10kW
F15-010	Photovoltaic	10kW
F16-010	Photovoltaic	10kW
F17-010	Photovoltaic	10kW
F18-010	Photovoltaic	10kW
F22-009	Photovoltaic	8.385kW
F24-008	Photovoltaic	8.6kW
F30-009	Photovoltaic	9kW
F31-007	Photovoltaic	6.5kW
F34-010	Photovoltaic	10kW
F36-004	Photovoltaic	3.8kW
F37-009	Photovoltaic	9kW
F38-009	Photovoltaic	8.6kW
F39-009	Photovoltaic	9.18kW
F42-008	Photovoltaic	7.6kW
F44-005	Photovoltaic	5kW
F45-008	Photovoltaic	7.6kW
F49-008	Photovoltaic	7.6kW
F50-006	Photovoltaic	5kW
F51-008	Photovoltaic	7.6kW
F52-008	Photovoltaic	7.6kW
F54-008	Photovoltaic	7.6kW
F55-008	Photovoltaic	7.6kW
F56-008	Photovoltaic	7.6kW
F57-008	Photovoltaic	7.6kW
F59-008	Photovoltaic	7.6kW
F63-008	Photovoltaic	7.6kW
Total		**266kW**

Table 4 –Connections for Services over the Historical Period (2017-2022)

Service	2017 Count (#)	2018 Count (#)	2019 Count (#)	2020 Count (#)	2021 Count (#)	2022 Count (#)
MicroFIT	1	10	0	0	0	0
FIT	0	2	0	0	0	0
Net Metering - Solar	0	0	0	1	0	1

4 SYSTEM ASSESSMENT TO IDENTIFY CONSTRAINTS

OHL has set conservative parameters for determining the available capacity for connecting REG projects. OHL determined the available generation capacity at 10% of the peak loading of each feeder and Distribution Station.

Table 5 – Feeder Distributed Generation Connection Capacity

Feeder Name	Approximate Maximum Capacity (MW) for Generation Connections	System Constraints for Connection of Generation	Existing Generation Connections Capacity (MW)	Available Capacity (MW) for Additional Generation Connections
GV-F2 Feeder	0.31	10% of peak demand	0.04	0.27
M5 Feeder	1.41	10% of peak demand	0.31	1.1
M23 Feeder	1.3	10% of peak demand	0.31	0.99
M25 Feeder	0.92	10% of peak demand	0.84	0.08
M26 Feeder	1.46	10% of peak demand	0.55	0.91

Table 6 – 4.16 kV Stations Distributed Generation Connection Capacity

Distribution Station	Approximate Maximum Capacity (MW) for Generation Connections	System Constraints for Connection of Generation	Existing Generation Connections Capacity (MW)	Available Capacity (MW) for Additional Generation Connections
MS2	0.18	10% of peak demand	0.009	0.17
MS3	0.18	10% of peak demand	0.008	0.10
MS4	0.12	10% of peak demand	0.044	0.08

5 PROPOSED INVESTMENTS TO FACILITATE NEW CONNECTIONS

OHL currently has no planned REG investments.

Appendix G – 2022 Regional Plan

South Georgian Bay-Muskoka

REGIONAL INFRASTRUCTURE PLAN

December 16, 2022

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Prepared by:
Hydro One Networks Inc. (Lead Transmitter)

With support from:

Company
Independent Electricity System Operator (IESO)
Alectra Utilities Corporation (Alectra)
Hydro One Networks Inc. (Distribution)
InnPower
Orangeville Hydro
Elexicon Energy
Lakeland Power
Epcor Electricity Distribution Ontario Inc
Newmarket-Tay Power Distribution Ltd
Wasaga Distribution Inc.

Disclaimer

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group.

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 Technical Working Group.

Technical Working Group 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 TECHNICAL WORKING GROUP IN ACCORDANCE WITH 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 SOUTH GEORGIAN BAY-MUSKOKA REGION.

The participants of the South Georgian Bay-Muskoka Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangevile Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

This RIP is the final phase of the second cycle of the South Georgian Bay-Muskoka Regional Planning (RP) process. It follows the completion of the South Georgian Bay-Muskoka Integrated Regional Resource Plan ("IRRP") which was subdivided into two sub-regions; Barrie Innisfil and Parry Sound/Muskoka both completed in May 2022. This also follows completion of the South Georgian Bay-Muskoka Needs Assessment ("NA") and Scoping Assessment ("SA") in April 2020 and November 2020, respectively.

The South Georgian Bay-Muskoka RIP provides a consolidated summary of needs and recommended plans for the region over a 10-year planning horizon (2022-2032) based on available information. The load forecast for the 2033-2042 period is provided to show the longer term needs and trend. All needs for this long-term horizon will be reviewed again and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in August 2017 with the publication of the South Georgian Bay-Muskoka RIP report, which provided a description of needs and recommendations of preferred wires plans to address near-term needs.

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

The following needs and projects identified in the previous regional planning cycle have been completed:

- Orillia TS M6E/M7E Switches (2021) - Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS (2021) – Replacement of end-of-life (EOL) 230/44kV 42MVA (T1/T2) transformers with new 230/44kV 83MVA units.

The following needs and projects identified in the previous regional planning cycle are currently underway:

- Parry Sound TS (2023) - Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment.

- Barrie TS (2023) Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV.

- Orangeville TS (2023)- Replace existing T1/T2 230/44/27.6 kV 75/125 MVA transformers with two 230/27.6 kV 50/83 MVA units and reconfigure the dual voltage switchyard to a standard DESN that would supply the 27.6 kV load. Also replace and upgrade T3/T4 230/44 kV 50/83 MVA transformers with two 230/44 kV 75/125 MVA units to accommodate additional capacity.

II. Newely Identified needs:

The major infrastructure investments in this 2nd cycle recommended by the TWG in the South Georgian Bay-Muskoka Region over the near and medium-term (2022-2032) period are given in Table 1 below, along with their planned in-service date and budgetary estimate for planning purposes.

Table 1. South Georgian Bay-Muskoka Region - Recommended Plans over the 2022-2032 Study Period

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[1]	Cost ($M)[2]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal - Transmission Line	M6E / M7E (Orillia TS x Coopers Fls)	Replace end- f-life (EOL) transmission line conductor (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace EOL transmission line conductor and associated assets (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace EOL transmission line conductor and associated assets (62 km)	HONI	2028	70
Asset Renewal - Transmission Station	Wallace TS	Replace existing EOL 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units	HONI	2025	25
	Midhurst TS	Replace existing 230/44kV 125MVA EOL transformer (T4) with a new 230/44kV 125MVA unit	HONI	2026	12
	Orillia TS	Replace existing EOL 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing EOL 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing EOL 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

The South Georgian Bay-Muskoka TWG recommends that Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 1 while keeping the TWG apprised of project status.

[1] Planned in-service dates are tentative and subject to change

[2] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The next regional planning cycle for the South Georgian Bay-Muskoka Region must be triggered within five years, beginning with the Needs Assessment ("NA") phase. It is expected that the next NA will start in Q2 2025. However, the next regional planning cycle can be started earlier if required to address any emerging needs.

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1. INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Technical Working Group ("TWG") in accordance with the regional planning process established by the Ontario Energy Board ("OEB") in 2013. The TWG included members from the following organizations:

- Independent Electricity System Operator ("IESO")
- Alectra Utilities Corporation ("Alectra")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangeville Hydro
- Lakeland Power
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

Electrical supply to the South Georgian Bay-Muskoka region is provided through two (2) 500/230kV auto-transformers at Essa TS, the 230kV transmission lines connecting Minden TS to Des Joachims TS, the 230kV circuits E8V and E9V coming from Orangeville TS, and the single 115kV circuit S2S connecting to Owen Sound TS. There are sixteen (16) Hydro One step-down transformer stations in the region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders. Figure 1-1 represents the South Georgian Bay-Muskoka Region Map.

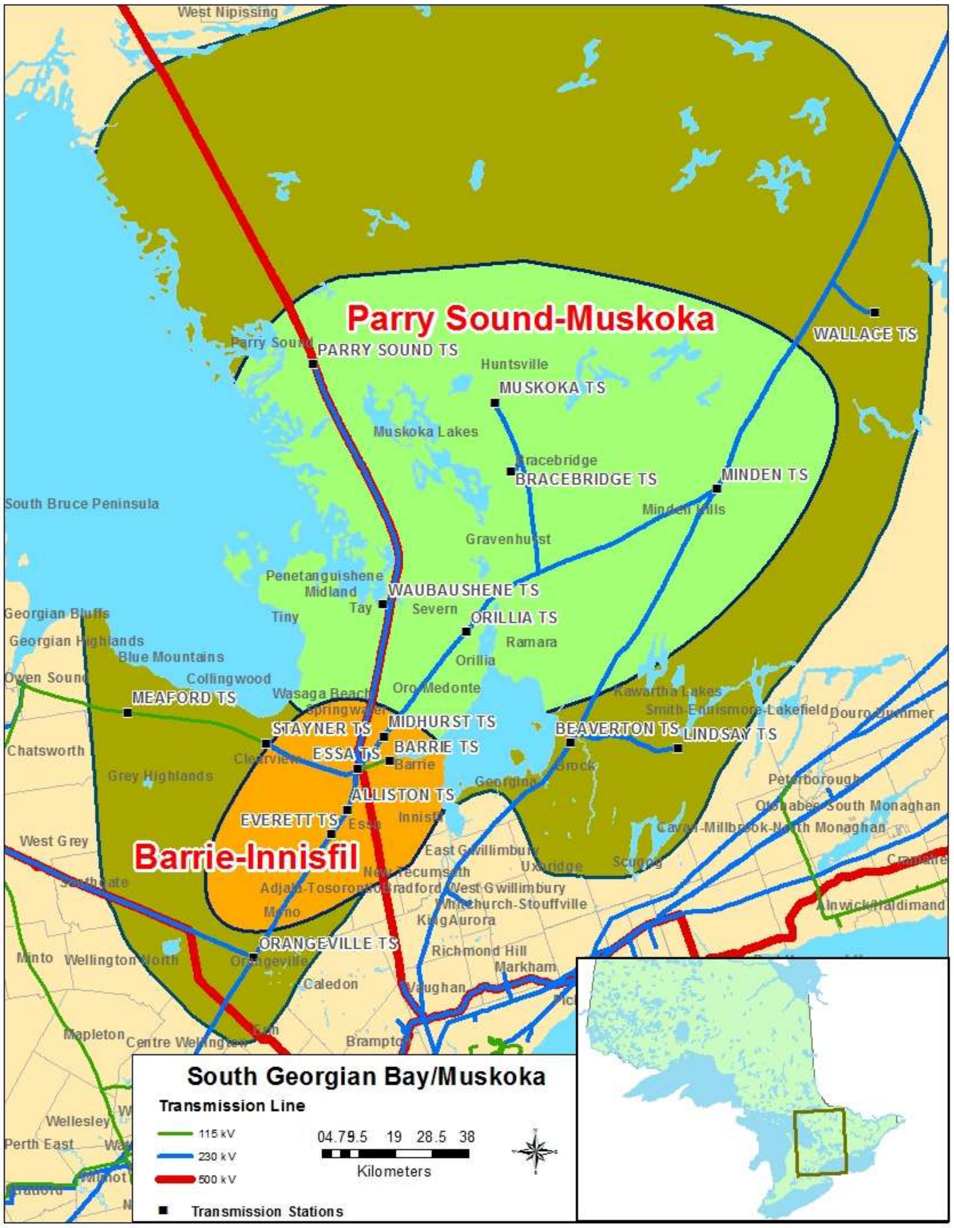


Figure 1-1 South Georgian Bay-Muskoka Region Map

1.1 Objectives and Scope

This RIP report examines the needs in the South Georgian Bay-Muskoka Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- Identify investments in transmission and distribution facilities or both 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, asset renewal for major high voltage transmission equipment, transmission and distribution system capability along with any updates with respect to local plans, conservation and demand management ("CDM"), 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 needs and relevant wires plans to address near and medium-term needs (2022-2032) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2022-2032 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the South Georgian Bay-Muskoka IRRP or identified by the TWG.

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 describes the results of the adequacy assessment of the transmission facilities in the region over the study period and identifies the needs;
- Section 7 discusses the needs, provides alternatives to address each need, and recommends a preferred solutions; and,
- Section 8 provides the conclusion and next steps.

2. REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at essentially 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 in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: The Needs Assessment ("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 Technical Working Group (TWG) determines whether further regional coordination is necessary to address them. If no further regional coordination is required to address the need(s), further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer to develop a Local Plan ("LP") to address them. These needs are local in nature and can be best addressed by a straightforward wires solution. The TWG considers various factors in determining that a LP is the appropriate planning approach.

In situations where identified needs require further coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the TWG, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and decides 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 which 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 and establishes a Local Advisory Committee (LAC) in the region or sub-region.

The RIP phase is the 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 these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated 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 the LDC(s). Respecting the OEB timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the regional planning process taking effect.
- The NA, SA, IRRP and LP phases of regional planning.
- Conducting wires planning as part of the RIP for the region or sub-region.
- 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.

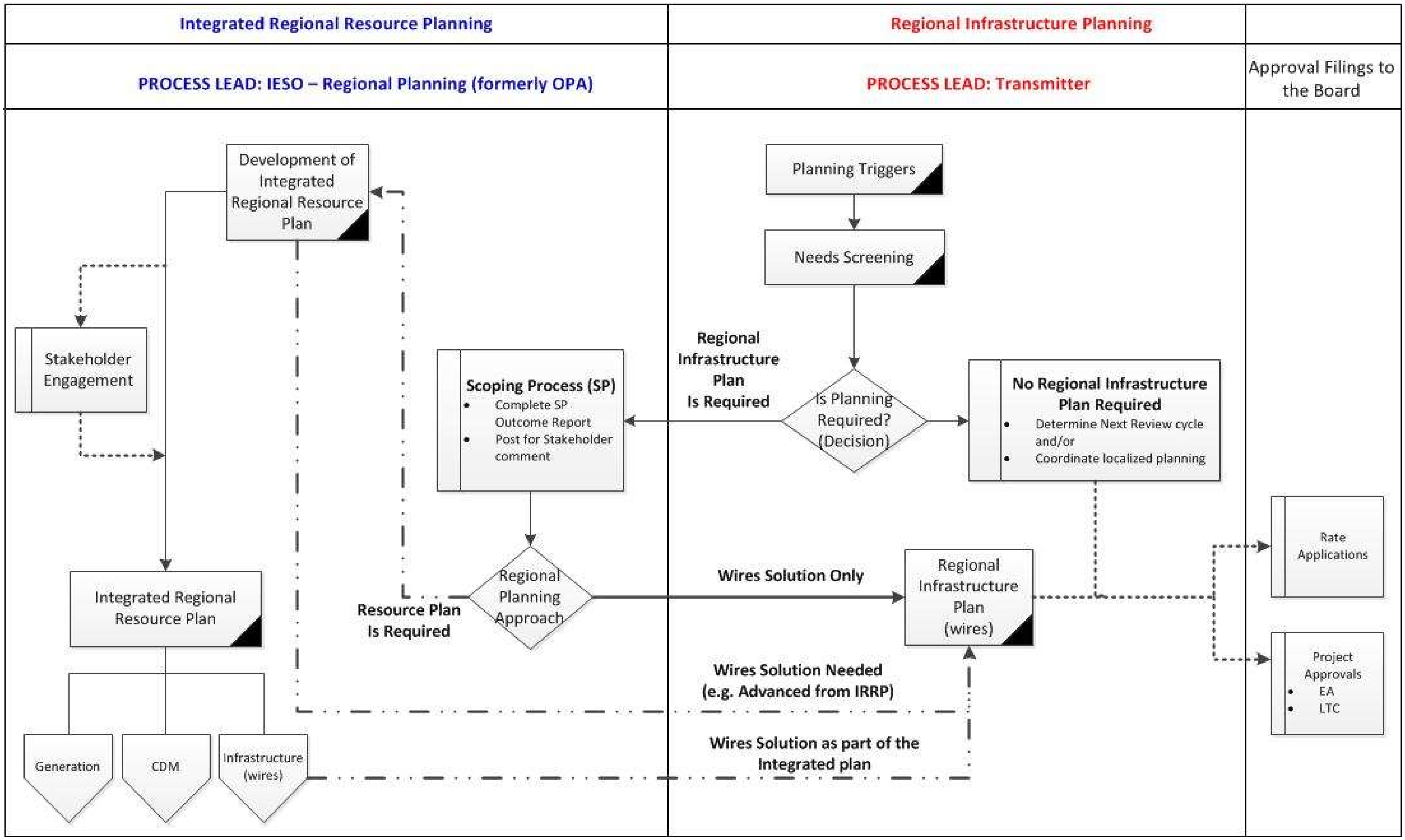


Figure 2-1 Regional Planning Process Flowchart

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 RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) 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. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset condition, 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. Additional near and medium-term needs may be identified at this stage.

3. Alternative Development: The third step is the development of wires options to address the needs and determine 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.

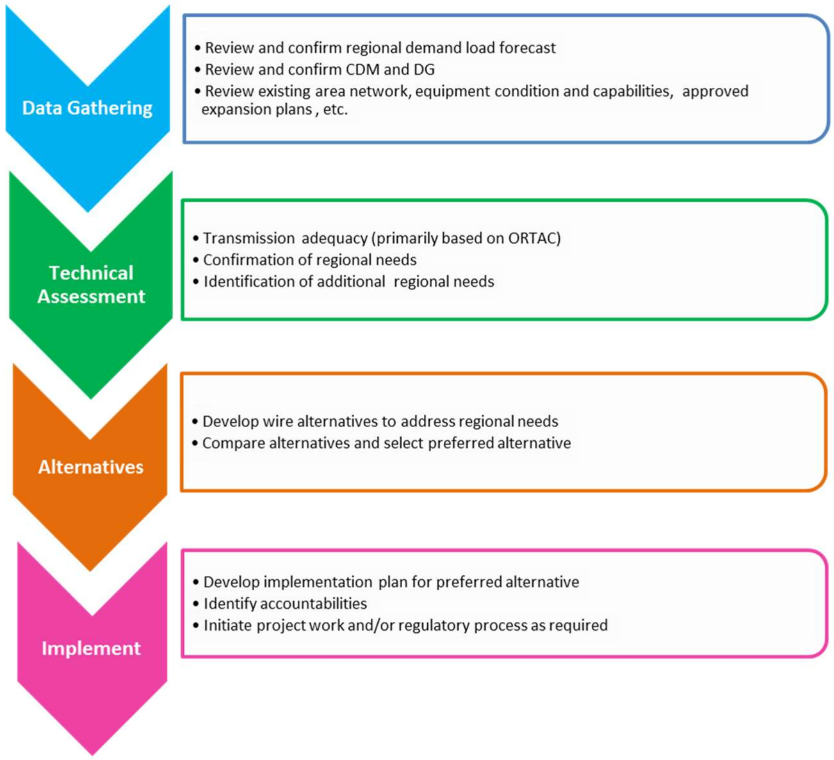


Figure 2-2 RIP Methodology

3. REGIONAL CHARACTERISTICS

THE SOUTH GEORGIAN BAY/MUSKOKA REGION IS COMPRISED OF THE BARRIE/INNISFIL AND THE PARRY SOUND/MUSKOKA SUB-REGIONS. ELECTRICAL SUPPLY TO THE REGION IS PROVIDED FROM TWO AUTO-TRANSFORMERS AT ESSA TS, THE 230KV TRANSMISSION LINES D1M, D2M, D3M AND D4M CONNECTING MINDEN TS TO DES JOACHIMS TS, THE 230KV CIRCUITS E8V AND E9V COMING FROM ORANGEVILLE TS AND THE SINGLE 115KV CIRCUIT S2S CONNECTING TO OWEN SOUND TS.

The existing facilities in the Region are summarized below and depicted in the single line diagram shown in Figure 3-1. The 500kV system is part of the bulk power system and is not studied as part of this report.

There are sixteen (16) HONI step-down transformer stations in the Region, most of which are supplied by circuits radiating out from Essa TS, and the majority of the distribution system is at 44kV, except for Orangeville TS which has 27.6kV and 44kV feeders.

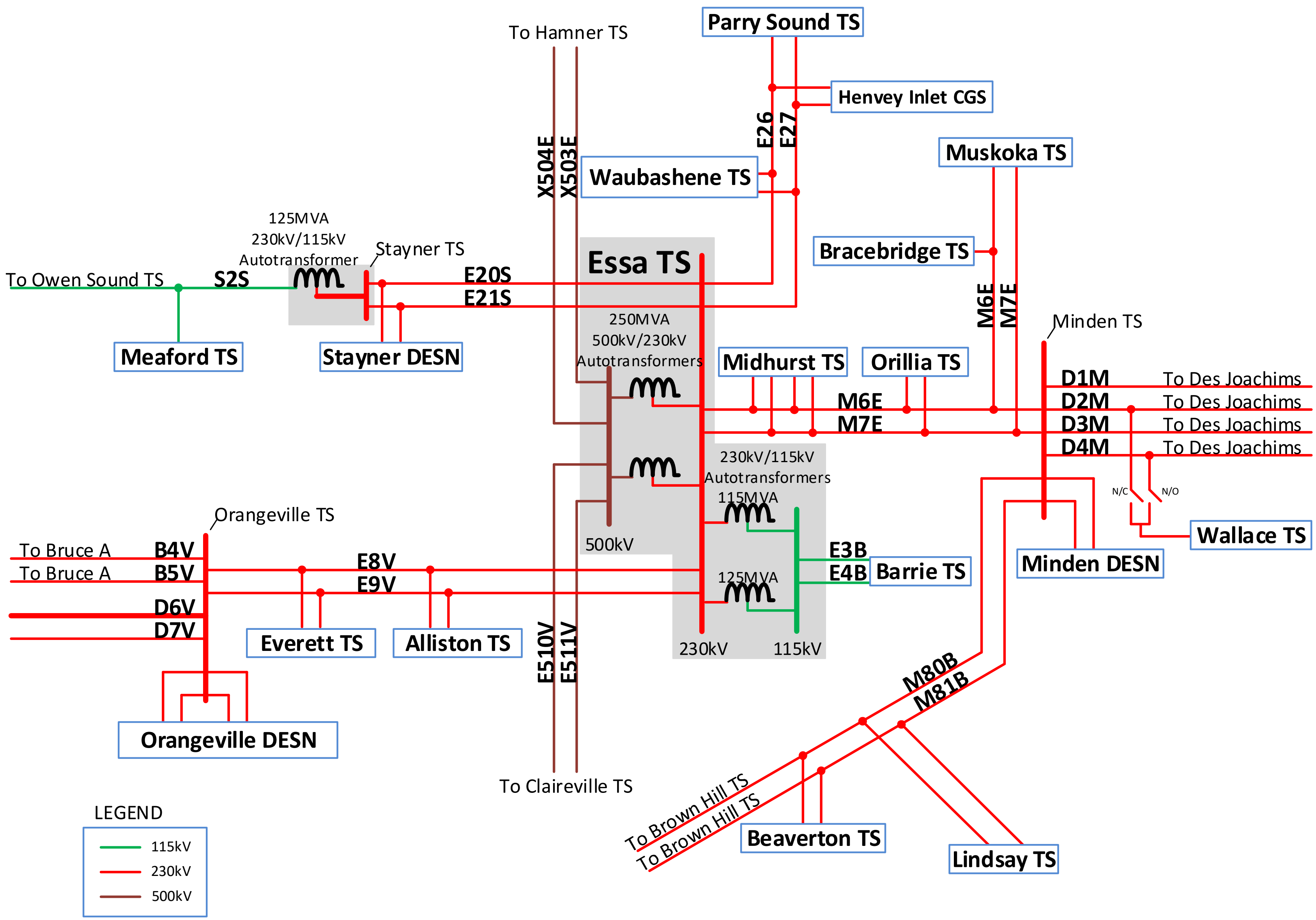
The April 2020 South Georgian Bay/Muskoka Region second cycle NA report, prepared by Hydro One, considered the South Georgian Bay/Muskoka as a whole. Subsequently as a result of the Scoping Assessment, the South Georgian Bay/Muskoka Region was divided into two sub-regions, Barrie/Innisfil Sub-Region and Parry Sound-Muskoka Sub-Region.

The Barrie/Innisfil Sub-Region roughly encompasses the City of Barrie and the towns of Innisfil, New Tecumseth and Bradford West Gwillimbury. It includes the townships of Essa, Springwater, Clearview and Mulmur, Adjala-Tosorontio. The Barrie/Innisfil Sub-Region includes the areas supplied by Midhurst TS, Barrie TS, Everett TS, and Alliston TS, and transmission circuits E8V/E9V, E3B/E4B, and M6E/M7E.

This Parry Sound/Muskoka sub-region roughly encompasses the Districts of Muskoka and Parry Sound, and the northern part of Simcoe County. The Parry Sound/Muskoka Sub-Region includes the areas supplied by Parry Sound TS, Waubaushene TS, Orillia TS, Bracebridge TS, Muskoka TS, Minden TS, and transmission circuits M6E/M7E and E26/E27.

The following circuits are not included in the South Georgian Bay/Muskoka Region:

- The 230kV circuits, B4V and B5V, and all stations which they supply. These circuits and stations are included in the Greater Bruce/Huron Region.
- The 230kV circuits, D6V and D7V, and all stations which they supply. These circuits and stations are included in the Kitchener/Waterloo/Cambridge/Guelph Region.



Note: BATU project will convert E3B/E4B to 230kV and connect Barrie TS directly to Essa TS 230kV bus (In-Service 2023)

Figure 3-1 South Georgian Bay-Muskoka Region Single Line Diagram

4. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

OVER THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN COMPLETED BY HYDRO ONE, OR ARE CURRENTLY UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

A summary and brief description of the major projects completed and/or currently underway over the last ten years is provided below:

- Midhurst TS and Orillia TS Capacitor Banks (2012) – Installation of four (4) 44kV, 32.4 MVAr capacitor banks at Midhurst TS and Orillia TS (two banks at each station) to minimize post-contingency voltage decline on the low voltage buses at both stations and defer the overload on circuit M6E.

  Meaford TS Transformer Replacement (2015) – The 115/44 kV, 25/42 MVA T1/T2 transformers were at end-of-life (EOL) and replaced like-for-like.

- Orillia TS M6E/M7E Switches (2021) – Loss of M6E and M7E resulted in violation of ORTAC load restoration criteria based on the peak load forecast. Hydro One installed new 230kV motorized disconnect switches on the M6E and M7E circuits (at Orillia TS) to improve load restoration time.

- Minden TS Transformer Replacement (2021) – The 230/44kV, 42MVA T1/T2 transformers were at EOL and replaced with new 230/44kV 83MVA units.

The following projects are underway:

- Barrie TS (2023) – This investment will convert the existing 115kV E3B/E4B circuits to 230kV and connect directly to the Essa 230kV bus. Barrie TS will be rebuilt with new 230/44kV 75/125MVA transformers and connect to the new 230kV E28/E29B circuits. The 230/115kV autotransformers at Essa TS will also be removed as part of this investment.

- Orangeville (2023) – Based on asset condition assessment the existing T3/T4 230/44kV 83MVA transformers will be replaced with new 125MVA units and also, the existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) be replaced with new dual winding 230/27.6, 83MVA units. This investment also involves reconfiguration of low voltage equipment and transfering existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN.

- Parry Sound TS (2023) - Parry Sound TS transformer supply capacity has been exceeded, and transformers have also been assessed at being end of life and in need of replacement due to their asset conditions. Hydro One will be installing new 230/44kV 83MVA transformers units to address both end of life and capacity needs at this station.

5. FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

During the study period, the load in the South Georgian Bay-Muskoka Region is expected to grow at an average annual rate of approximately 2% (summer) and 1.8% (winter) from 2022 to 2032.

Figure 5-1 shows the South Georgian Bay-Muskoka Region extreme summer weather net load forecast from 2022 to 2042. The load forecasts from the Barrie Innisfil sub-region IRRP and Parry Sound/Muskoka sub-region IRRP were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.
Non-coincident forecast for the individual stations in the region is available in Appendix D and is used to determine any need for station capacity relief.

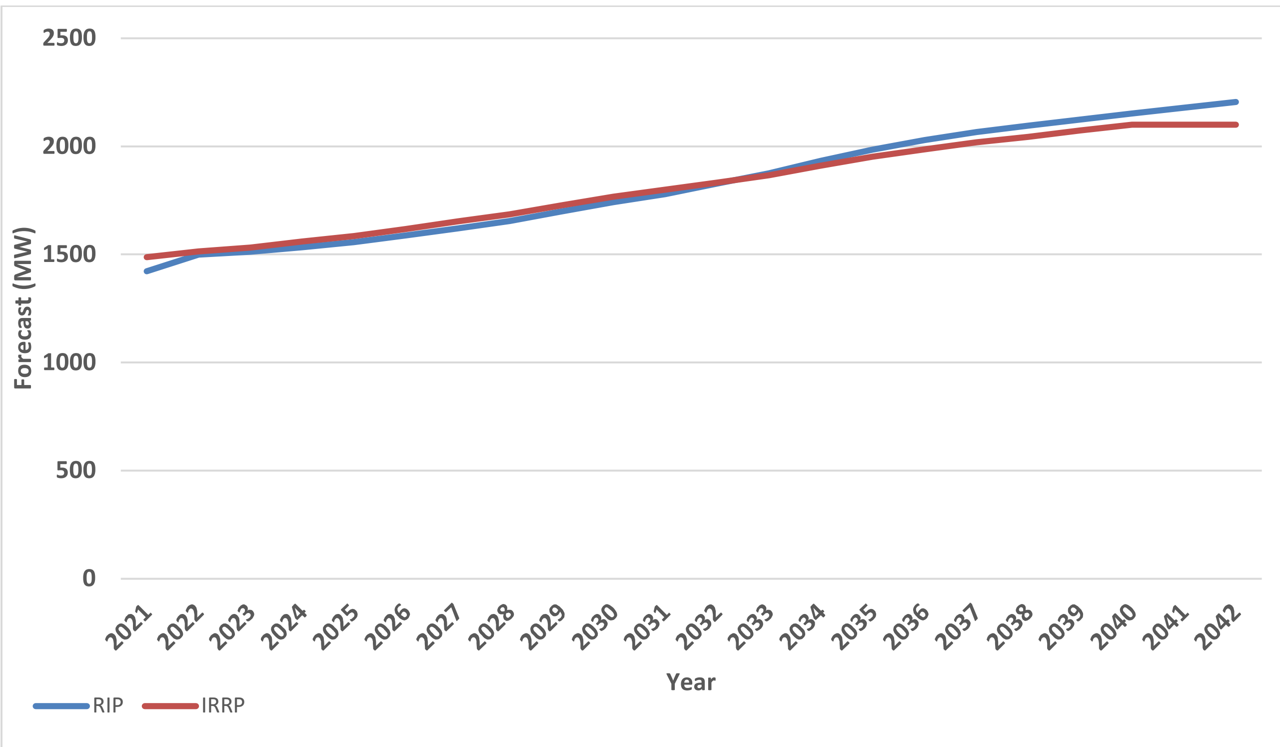


Figure 5-1 South Georgian Bay-Muskoka Region Non–Coincident Net Summer Peak Load Forecast

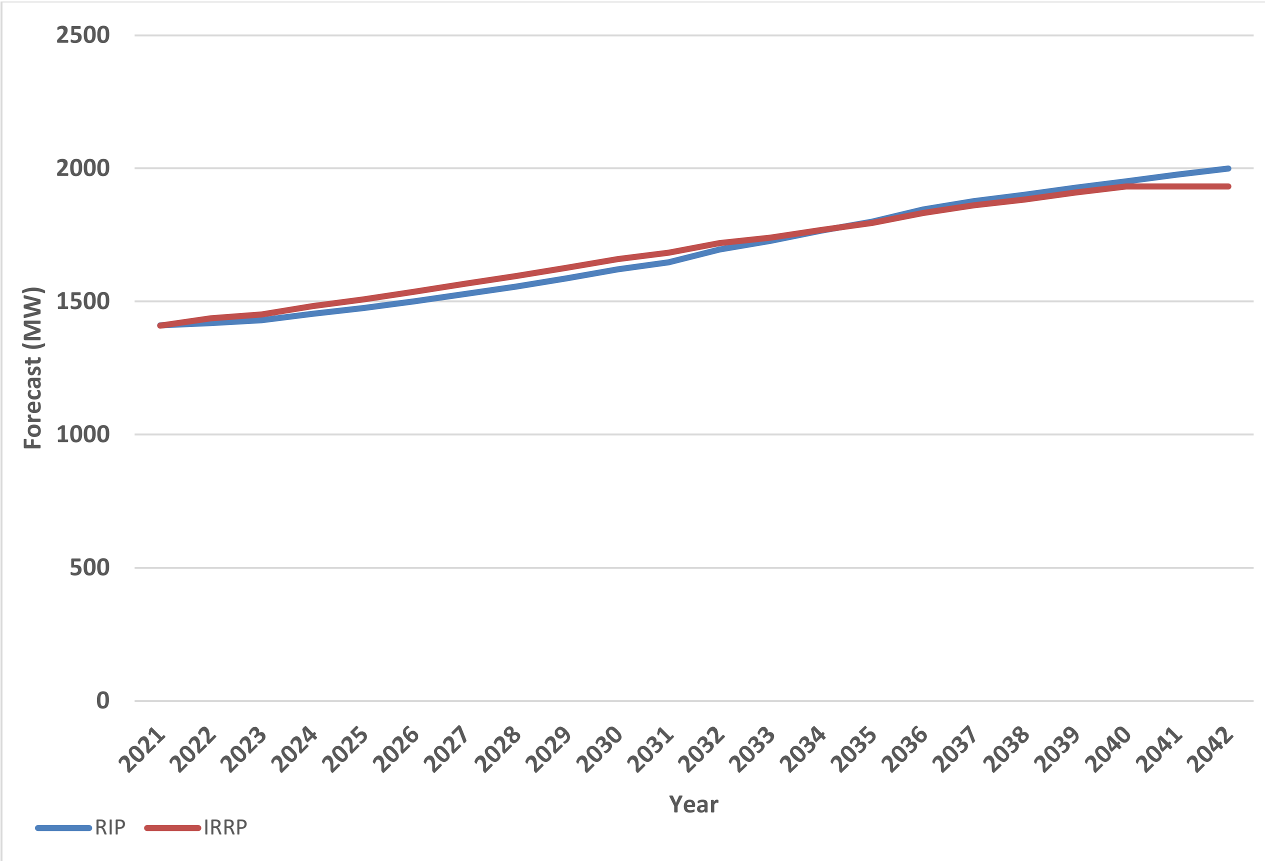


Figure 5-2 South Georgian Bay-Muskoka Region Non–Coincident Net Winter Peak Load Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2022-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the IESO's Barrie Innisfil sub-region and Parry Sound/Muskoka sub-region IRRPs.
- LDCs reconfirmed load forecasts up to 2040. The additional two years of forecasts were extrapolated based on growth rate as a reasonable position to complete the 20 years period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- Both summer and winter loads were considered to assess line and transformer loadings.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Bulk transmission line capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6. ADEQUACY OF EXISTING FACILITIES AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE SOUTH GEORGIAN BAY-MUSKOKA REGION AND LISTS THE FACILITIES REQUIRING REINFORCEMENT OVER THE NEAR AND MID-TERM PERIOD.

Within the current regional planning cycle, four regional assessments have been conducted for the South Georgian Bay-Muskoka Region. The findings of these assessments are inputs to this RIP. These assessments are:

1) South Georgian Bay-Muskoka Region second cycle Needs Assessment (NA) Report, April 2020
2) South Georgian Bay/Muskoka second cycle Scoping Assessment Outcome Report, November 2020
3) Barrie/Innisfil sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022
4) Parry Sound/Muskoka sub-region second cycle Integrated Regional Resource Planning (IRRP), May 2022

The NA and IRRP reports identified several regional needs based on the forecasted load demand over the near to mid-term period. A detailed description and status of plans to meet these needs is given in Section 7.

This section provides a review of the adequacy of the transmission lines and stations in the South Georgian Bay/Muskoka Region. The adequacy is assessed using the load forecasts provided in Appendices D. The assessment assumes all projects currently underway (described in section 4) are in-service and specifically, the Barrie Area Transmission Reinforcement project and Orangeville/Parry Sound transformer replacements are in-service by 2023.

Sections 6.1- 6.3 present the results of the adequacy assessment and Table 6-1 lists the region's near, mid, and long-term needs identified in both the IRRP and RIP phases.

6.1 500 kV and 230 kV Transmission Facilities

All 500 kV and 230 kV transmission circuits in the South Georgian Bay-Muskoka Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the rest of Ontario's transmission system. The 230 kV circuits also serve local area stations within the region and the power flow on these circuits vary depending on the bulk system transfers as well as the local area loads.

6.1.1 500/230 kV Transformation Facilities

Bulk power supply to the South Georgian Bay-Muskoka Region is provided by 500/230 kV autotransformers at Essa TS which serves as a hub for major power flows between Hanmer TS (Sudbury) and Clairville TS (Toronto). Additional support for the region is provided from the 230 kV generation facilities (Des Joachims GS, Henvey Inlet CGS)

6.1.2 230 & 115 kV Transmission Circuits

The 230kV circuits in the region are as follows;

- E20S/E21S (Essa TS x Stayner TS)
- E26/E27 (Essa TS x Parry Sound TS)
- M6E/M7E (Essa TS x Minden TS)
- D1M/D2M/D3M/D4M (Minden TS x Des Joachims)
- 115 kV - S2S (Stayner TS x Owen Sound TS)

Table 6-1 below highlights the line section(s) and violations identified in the IRRP and reaffirmed in this RIP.

Table 6-1 South Georgian Bay-Muskoka Region - Lines Sections Exceeding ratings

No.	Line	Section	Contingency	Year Line Rating exceeded
1	M6E/M7E	Essa TS x Midhurst TS	N-1[1]	2034
2	M6E	Minden x Coopers Fls JCT	N-1[2]	2038
3	M6E	Minden x Coopers Fls JCT	N-1-1[3]	2040

[1] Loss of one of either M6E or M7E will result in overload of the companion circuit.
[2] Minden TS HL7 breaker fail.
[3] M7E O/S followed by loss of Essa TS T3

The options and preferred solutions to address these needs are discussed further in Section 7 of the report.

6.2 Step-Down Transformation Facilities

There are sixteen (16) step-down transformer stations in the South Georgian Bay-Muskoka Region as listed in Table 6-2.

Table 6-2 South Georgian Bay-Muskoka Region - Step-Down Transformer Stations

Alliston TS	Everett TS	Minden TS	Parry Sound TS
Barrie TS	Lindsay TS	Muskoka TS	Stayner TS
Beaverton TS	Meaford TS	Orangeville TS	Wallace TS
Bracebridge TS	Midhurst TS	Orillia TS	Waubaushene TS

This RIP reviewed the step-down transformation capacity for the stations within the South Georgian Bay-Muskoka Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the 2022-2032 study period are shown in Table 6-3 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) 10-day LTR.

Table 6-3 South Georgian Bay-Muskoka Region - Stations Requiring Relief in the study period (2022-2032)

Station	Capacity (MW)	2022 Loading (MW)	Need Date
Everett TS	86	85	Immediate
Barrie TS	162[3]	98	2027
Waubaushene TS	94	90	2027

Further, based on the load forecast, the stations requiring relief beyond the study period are listed below:

- Midhurst TS (T1/T2) – 2033
- Midhurst TS (T3/T4) – 2034

6.3 Asset Renewal for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period as listed in Table 6-4 below.

Asset renewal needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as (but not limited to):

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

The major high voltage equipment considered includes the following:

1. 230/115kV autotransformers;
2. 230 and 115kV load serving step-down transformers;
3. 230 and 115kV breakers where:
    - replacement of six breakers or more than 50% of station breakers, the lesser of the two
4. 230 and 115kV transmission lines requiring refurbishment where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
5. 230 and 115kV underground cable requiring replacement where:
    - Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

[3] After completion of the BATU project

Table 6-4 South Georgian Bay-Muskoka Region - Planned Replacement Work

No.	Station / Line Section	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS (T1/T2)	2023
2	Orangeville TS (T1/T2 & T3/T4)	2023
3	Parry Sound TS (T1/T2)	2023
	In Development	
4	Wallace TS (T3/T4)	2025
5	Midhurst TS (T4)	2026
6	Orillia TS (T2)	2025
7	Bracebridge TS (T1)	2026
8	Waubaushene TS T5/T6	2027
9	Alliston TS (T3/T4)	2030
10	M6E/M7E – Cooper Falls Jct x Orillia TS	2026
11	E8V/E9V – Orangeville TS x Essa Jct	2027
12	D1M/D2M – Otter Creek Jct x Minden TS	2028

*The planned in-service dates are tentative and subject to change.

6.4 Load Security and Load Restoration

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[4] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interruped in excess of 250 MW must be restored within 30 minutes.

This RIP further confirms there are no identified load security and restoration violations within the study period. The technical working group does not recommend any further action.

[4] These approximate restoration times are intended for locations that are near staffed centres. In more remote locations, restoration times should be commensurate with travel times and accessibility

7. REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The electrical infrastructure needs for the South Georgian Bay-Muskoka Region are summarized in Table 7-1. These needs include those previously identified in the NA for the South Georgian Bay-Muskoka Region and IRRPs for the Barrie/Innisfil and the Parry Sound/Muskoka Sub-Regions as well as any new needs identified during the RIP phase. All estimated costs included in the altnerative analysis are considered as planning budgetary estimates and are used for comparative purposes only.

Table 7-1 South Georgian Bay-Muskoka Region – Near, Medium and Long Term Needs

Type	Section	Needs	Timing
Station Capacity	7.1	Everett TS	2023
		Barrie TS	2027
		Waubaushene	2027
		Midhurst TS	2033/2034
		Minden TS	2036
Supply Capacity	7.2	M6E/M7E (Essa x Midhurst)	2034
		M6E/M7E (Minden x Coopers Fls)	2038
Asset Renewal for Major HV Transmission Equipment	7.3.1	M6E/M7E (Orillia x Coopers Fls)	2026
		E8V/E9V (Orangeville TS x Essa Jct)	2027
		D1M/D2M (Otter Creek Jct x Minden TS)	2028
	7.3.2	Wallace TS (T3/T4)	2025
		Midhurst TS (T4)	2026
		Orillia TS (T2)	2025
		Bracebridge TS (T1)	2026
		Waubaushene TS (T5/T6)	2027
		Alliston TS (T3/T4)	2030
Load Security/Restoration	7.4	None Identified in this planning cycle	-

7.1 Station Capacity Needs

7.1.1 Everett TS

Everett TS is 230/44kV 50/83MVA transformer station with a summer and winter 10-Day LTR of 86MW. Load at this station is forecasted to increase up to 105MW by the end of 2032. Supply capacity is presently limited by a current transformer (CT) ratio setting on the transformer breaker bushing, thereby restricting the ability to utilize the full supply capability of the transformers.

Table 7-2 Everett TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Everett TS	86	85	86	87	88	90	92	93	95	97	100	105

The following alternatives were considered to address Everett TS capacity need:

Alternative 1 - Maintain Status Quo: This alternative was considered and rejected as it does not provide supply capacity to area customers during the study period. Under this scenario load cannot be increased at this station.

Alternative 2 – Replace and upgrade T1/T2 with new 75/125MVA units: Under this alternative the existing T1/T2 transformers will be replaced with new 75/125MVA transformers. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire the T1/T2 transformers. These transformers remain in acceptable condition are not scheduled to be replaced by Hydro One within the study period.

Alternative 3 – Modify the CT Ratio: This alternative would require modifying the CT ratio of the low voltage transformer breaker CTs to realize the full supply capacity of the transformers.

The TWG recommends Alternative 3 as the preferred and cost effective alternative for addressing the need. CT ratios are established based on expected loading at a station and typically lower when transformer stations are initially constructed. As the load increases these ratios must be adjusted to ensure protection, control and metering continue to operate as intended. This solution utilizes existing assets without incurring additional high capital expenditures and will allow the station LTR to increase to 108MW (summer) and 177MW (winter) once completed. The budgetary cost for this alternative is expected to be $0.5M

7.1.2 Barrie TS

The Barrie Area Transmission Upgrade (BATU) project is presently underway and scheduled to be in-service in 2023. Barrie TS will be upgraded to a new 230/44kV 125MVA transformer station with 8 feeder positions (six for Alectra Utilities and two for Hydro One Distribution with InnPower as an embedded customer).

Barrie TS will have a 10-Day LTR of 162MW and the forecasted load will exceed its normal supply capacity in 2028 based on the summer demand forecast (see Table 7-3 below). Coincident with the station capacity violation, Hydro One distribution and its embedded LDC (InnPower) will also see a supply capacity constraint on their two 44kV feeders in 2028. Minor capacity increases can be accommodated on the 44kV system, but only on an emergency basis and cannot be used as a permanent supply solution for increased load growth. InnPower will need new supply capacity into the Innisfil service territory to service its load growth beyond the 2-feeder capacity that Barrie TS can supply.

An Innisfil supply study was completed to evaluate supply options for InnPower and consequently help to offload demand from Barrie TS. Results of this study are described in the alternatives below.

Table 7-3 Barrie TS Load Forecast

Station	LTR (MW)		Load Forecast									
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Barrie TS	162	98	119	128	141	154	161	163	164	167	170	174

Alternative 1 - Maintain Status Quo:

This alternative was considered and rejected as it does not address future station capacity restrictions at Barrie TS, nor does it provide InnPower with the mid-term supply capacity required for load growth in their service territory.

Alternative 2 – Inn Power to connect to existing Alectra Feeder as embedded customer:

This solution was initially discussed by the TWG in the first planning cycle to provide increased supply to InnPower without additional station work at Barrie TS. Spare feeder capacity is not available and thus, this alternative fails to meet the full supply needs within the study period and will need to be combined with alternate solutions. This alternative was rejected on this basis, and thus costs have not been explored further.

Alternative 3 – Install an Additional 44kV feeder position from Barrie TS:

This solution was discussed with the TWG and closely relates to Alternative 2. A new dedicated feeder position for InnPower will provide up to 25MW supply capacity, however this solution would still fail to meet the full supply needs of InnPower within the study period, and the increased load will still be seen at Barrie TS triggering a capacity need in 2028. This solution will need to be combined with alternate solutions to relieve Barrie TS. The combined transmission and distribution costs to install and construct a new distribution line from Barrie TS is estimated to cost $20M, however this alternative is rejected as it does address capacity needs at Barrie TS.

Alternative 4 – Load existing 44kV supply feeders beyond normal capacity

This alternative was explored by the TWG to increase supply on the two 44kV feeders from Barrie TS beyond the normal supply capacity. This solution requires increased voltage support on the distribution system along the feeders and will provide up to 20MW increased supply capacity (10MW/feeder). Distribution costs to facilitate increased feeder loading is estimated to cost $8M, however this alternative is rejected as it still does address Capacity needs at Barrie TS.

Alternative 5 – Provide 230kV tap connection to Innisfil service territory for new transformer station

This alternative involves construction of a 230/27.6kV 50/83MVA transformer station in Innisfil to supply the increased load demand forecast. This station will connect directly to the 230kV E28B/E29B circuits which will be completed in 2023 as part of the Barrie Area Transmission Upgrade project. A new 9km double circuit 230kV transmission line will be constructed to connect this new transformer station.

This alternative will provide increased supply capacity for InnPower within the study period and allow for load growth in the future. This alternative can be utilized as a standalone solution to meet the needs without additional interim investments or in conjunction with other alternatives presented above. This solution also allows InnPower to transfer load to this station which would otherwise be connected to Alliston TS. This transfer of load helps to mitigate a capacity need during the study period which would see an additional expenditure to increase supply capacity on the T3/T4 DESN at Alliston TS.
The estimated cost for this investment is expected to be $44M which is comprised of $14M for transmission line construction and $30M for a new transformer station.

The TWG recommends proceeding with Alternative 5. This alternative provides a robust transmission solution to meet InnPower's demand forecast and will also allow for future load growth beyond the study period. This solution will also help to relieve Barrie TS which will see a capacity need in 2028. Based on findings in the Needs Assessment and IRRP, Hydro One and InnPower have commenced development work on this alternative to meet the 2028 need date and TWG recommends continuing with this work.

7.1.3 Waubaushene TS

Waubaushene TS presently has 230/44 83MVA transformers (T5/T6) with a summer LTR of 94MW. This station will exceed its normal supply capacity in 2028 (see Table 7-4 below).

Summer overloading at this station continues to be of concern and the TWG agrees that a solution is required to address this need. Hydro One Distribution has permanently transferred 10MW of load from Waubaushene TS to Midhurst TS to help with recent summer loading concerns, however a solution is required to further address the upcoming supply capacity need.

Table 7-4 Waubaushene TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Waubaushene TS	94	90	90	91	92	93	94	96	97	99	100	102

Alternative 1 - Maintain Status Quo: This solution is not recommended as it does not address the supply capacity need at the station. This solution will prevent load growth at this station beyond 2027.

Alternative 2 – Load Transfer to neighboring stations

This solution was explored during the NA and IRRP phase. Hydro One distribution assessed transfer capability to other stations and determined that a maximum of 10MW of load could be transferred, and this was completed in Q1 2022. Further transfers are not feasible without significant distribution construction costs and regulators on the low voltage network estimated to be $ 5-10 M depending on feeder construction and voltage regulation.

Alternative 3 – Replace End-of-Life Waubaushene TS T5/T6 transformers with upgraded 125MVA units.

Replace and upgrade existing T5/T6 transformers with larger 75/125MVA units. This solution will increase supply capacity to allow load to continue to grow as per the demand forecast.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative for addressing the need. The existing T5/T6 transformers at Waubaushene TS have been identified by Hydro One as requiring replacement based on their asset condition and is planned for replacement in 2027. This date coincides with the supply capacity need timing as shown in Table 7.4 and thus the TWG agrees this is the ideal scenario to address the capacity need and right size the transformers. The budgetary cost for the replacement and upgrade of the transformers is expected to be $20M. Hydro One will follow Ontario Energy Board (OEB) approved procedures to determine appropriate cost allocation as this project addresses both a sustainment and capacity upgrade need.

7.1.4 Midhurst TS and Minden TS

As identified in Table 7-1, the stations listed below will require capacity relief beyond 2032. Based on the long-term horizon of these needs the load at these stations will be reviewed in the next regional planning cycle. The timing for capacity relief of these stations is shown below:

- Midhurst TS T1/T2: 2033 and Midhurst TS T3/T4: 2034
- Minden TS T3/T4: 2036

7.2 Supply Capacity Needs

The M6E/M7E circuits are a 230kV double circuit transmission line forming a critical path between Essa TS and Minden TS. These circuits are approximately 120 km long and serve to provide connection to load serving stations and provide a path for network flows. Based on the coincident load forecast of the stations in the region, sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The two circuit sections are described below:

1. Essa TS x Midhurst TS (10km) – For the loss of M6E or M7E, the companion circuit will exceed its Long-Term Emergency (LTE) rating as early as 2034 based on theload forecast.

2. Minden TS x Coopers Falls JCT (51km) – This section of transmission line will experience Long-Term Emergency (LTE) rating violations as early as 2038 for a Minden TS HL7 breaker failure, and Essa T3 contingency with M7E out of service.

Based on the long-term horizon of these needs solutions to address them will be further explored in the next regional planning cycle. Flows on this line and its violations are heavily influenced by area resource assumptions and demand forecast of the transformer stations connected to this circuits. IESO has also identified that incremental cost effective CDM, storage and other non-wires alternatives will be explored to address this need. The TWG will review this need in the next regionalplanning cycle and initiate an investment should this violation be advanced due to changing system conditions.

7.3 Asset Renewal Needs for Major HV Transmission Equipment

A number of Hydro One facilities in the South Georgian Bay-Muskoka Region will require replacement over the 2022-2032 study period. Hydro One is the only Transmission Asset Owner (TAO) in the Region.

The asset renewal assessment considers options for right sizing the equipment such as:

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

7.3.1 Transmission Line Refurbishment

The following transmission line sections were identified by Hydro One as requiring refurbishment over the study period based on asset condition assessment:

1. M6E/M7E Orillia x Coopers Fls – This is a 50km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2026.

2. E8V / E9V Orangeville TS X Essa JCT – This is a 112km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2027.

3. D1M / D2M Otter Creek JCT x Minden TS – This is a 124km 230kV line section that was in-serviced in 1950. Based on asset condition assessment, this line section requires like for like refurbishment to ensure supply reliability and safety is maintained. The planned in-service date for this investment is 2028.

7.3.2 Transmission Station Refurbishment

Hydro One identified a number of step-down transformers as requiring replacement over the study period based on asset condition assessment. Details of the planned work as recommended by the TWG are given in Table 7-5 below.

Table 7-5 Asset Renewal Plan-Transmission Stations

No.	Station	Planned In-Service Date*
	In Execution/Construction	
1	Barrie TS Replace and upgrade existing 115/44kV 83MVA transformers (T1/T2) with new 230kV/44kV 125MVA transformers. Remove Essa TS T1/T2 autotransformers and convert Barrie TS supply circuits (E3B/E4B) from 115kV to 230kV. This investment is also known as Barrie Area Transmission Upgrade (BATU) and will include replacement of end of life equipment at Essa TS, in addition to increasing both station and supply capacity to the area.	2023
2	Orangeville TS Replace and upgrade existing 230/44kV 83MVA transformers (T3/T4) with new 230/44kV 125MVA units. Replace and upgrade existing nonstandard three winding 230/44/27.6 125MVA transformers (T1/T2) with new dual winding 230/27.6 83MVA units. Reconfigure low voltage equipment and transfer existing 44kV feeders from T1/T2 DESN to the T3/T4 DESN. This replacement plan will decrease the risk of equipment failure and contribute to maintaining supply reliability to Orangeville Hydro and Hydro One Distribution customers in the Orangeville area.	2023
3	Parry Sound TS Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment. Replacement of these power transformers will help to maintain the reliability of supply and provide increased supply capacity to customers in the area by right sizing to 83MVA units.	2024
	In Development	
4	Wallace TS Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units. Replacement of Oil circuit breakers will also be part of this investment. This investment will help maintaining reliability of supply to Hydro One Distribution customers and reduce the risk of interruptions caused by station equipment failure.	2025

5	Midhurst TS Replace existing 230/44kV 125MVA T4 transformer with a new like-for-like unit. The T3/T4 DESN presently supplies load to Alectra though 8 x 44kV feeders. T4 is the sole unit that has been identified as requiring replacement due to poor asset condition. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure. Load growth in the area will be reviewed in the next regional planning cycle. The TWG will ensure solutions to increase supply capacity in the region are explored in advance of the need date.	2026
6	Orillia TS Replace existing 230/44kV 125MVA T2 transformer with a new like-for-like 230/44kV 125MVA unit. The T1 transformer was replaced in 2015 after failure and does not require replacement during this study period. This investment will help maintain reliability of supply to Hydro One Distribution customersand decrease the risk of interruptions caused by failure of transformer T2.	2025
7	Bracebridge TS Replace existing 230/44kV 83MVA transformer (T1) with new like-for-like 230/44kV 83MVA unit. Bracebridge TS presently has one transformer (T1) and is used to supply 2 x 44kV feeders and a backup for industrial pipeline operation. The load at this station is not expected to trigger installation of a second transformer and thus like-for-like replacement of T1 will be sufficient during the study period. This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2026
8	Waubaushene TS Replace existing 230/44 83MVA transformers (T5/T6) with new 125MVA units. This investment will help to maintain reliability of supply to area customers and provide increased supply capacity to meet demand forecast.	2027
9	Alliston TS Replace existing 230/44kV 83MVA transformers (T3/T4) with new like-for-like 230/44kV 83MVA units.	2030

	This investment will help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure and removal of legacy obsolete equipment.	

*The planned in-service year is tentative and is subject to change.

The above asset replacement plans have taken "right sizing" into consideration. All transformer replacements in the development phase are planned to be replacewith like-for-like units based on the load forecast in the study period and Hydro One standard equipment. The TWG recommends that Hydro One proceed with the above station sustainment work to ensure system reliability is maintained.

7.4 Load Security / Restoration

As indicated in section 6.4 there are no load security or restoration violations in the SGB-Muskoka region over the study period. The TWG will continue to monitor and take corrective action as needed.

7.5 Long Term Considerations

Like many other regions in Ontario, load growth in the SGB-Muskoka region will be directly impacted by new energy programs specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment.

8. CONCLUSION AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN REPORT CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE SOUTH GEORGIAN BAY-MUSKOKA REGION.

The major infrastructure investments recommended by the Technical Working Group (TWG) in the near and medium-term planning horizon (2022-2032) are provided in Table 8-1 below, along with their planned in-service dates and budgetary estimates for planning purposes.

Table 8-1 Recommended Plans in Region over the Next 10 Years

Need	Station / Circuit	Investment Description	Lead	Planned In-Service Date[5]	Cost ($M)[6]
Station Capacity	Everett TS	Modify current transformer (CT) ratio setting the low voltage 44kV transformer breakers	HONI	2023	0.5
	Barrie TS	Construct new 230/27.6kV 83MVA transformer station and extend and connect to 230kV E28B/E29B circuits	HONI / Inn Power	2027	44
	Waubaushene TS	Replace and upgrade existing end-of-life 230/44kV 83MVA transformers (T5/T6) with new 230/44kV 125MVA units.	HONI / Hydro One Dx	2027	20
Asset Renewal Needs for Major HV Transmission Equipment	M6E / M7E (Orillia TS x Coopers Fls)	Replace transmission line conductor and associated assets. (25km)	HONI	2026	30
	E8V / E9V (Orangeville TS x Essa JCT)	Replace transmission line conductor and associated assets. (56km)	HONI	2027	70
	D1M / D2M (Minden TS x Otter Creek JCT)	Replace transmission line conductor and associated assets. (62km)	HONI	2028	70
	Wallace TS	Replace existing 230/44kV 42MVA transformers (T3/T4) with new 230/44kV 42MVA units.	HONI	2030	25
	Midhurst TS	Replace existing 230/44kV 125MVA transformer (T4) with a new 230/44kV 125MVA unit.	HONI	2026	12
	Orillia TS	Replace existing 230/44kV 125MVA transformer (T2) with new 230/44kV 125MVA unit	HONI	2025	12
	Bracebridge TS	Replace existing 230/44kV 83MVA transformer (T1) with new 230/44kV 83MVA unit	HONI	2026	10
	Alliston TS	Replace existing 230/44kV 83MVA transformer (T3/T4) with new 230/44kV 83MVA units	HONI	2030	16

[5] The planned in-service dates are tentative and subject to change.

[6] Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required).

The South Georgian Bay-Muskoka TWG recommends Hydro One and LDCs continue with the implementation of infrastructure investments listed in Table 8-1. All the other identified needs/options in the long-term will be further reviewed by the TWG in the next regional planning cycle.

9. REFERENCES

[1] Independent Electricity System Operator, Barrie/Innisfil IRRP (2022)

[2] Independent Electricity System Operator, Parry Sound Muskoka IRRP (2022)

[3] Hydro One, South Georgian Bay/Muskoka Needs Assessment (2020)

[4] Hydro One, South Georgian Bay/Muskoka RIP (2017)

[5] Independent Electricity System Operator, Barrie/Innisfil IRRP (2016)

[6] Independent Electricity System Operator, Parry Sound/Muskoka IRRP (2016)

[7] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 August 07, 2007

[8] Ontario Energy Board, Transmission System Code (2018)

[9] Ontario Energy Board, Distribution system Code (2022)

APPENDIX A. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS

No.	Transformer Stations	Voltages (kV)
1.	Alliston TS	230/44
2.	Barrie TS	115/44
3.	Beaverton TS	230/44
4.	Bracebridge TS	230/44
5.	Essa TS	500/230/115
6.	Everett TS	230/44
7.	Lindsay TS	230/44
8.	Meaford TS	230/44
9.	Midhurst TS	230/44
10.	Minden TS	230/44
11.	Muskoka TS	230/44
12.	Orangeville TS	230/44/27.6
13.	Orillia TS	230/44
14.	Parry Sound TS	230/44
15.	Stayner TS	230/115/44
16.	Wallace TS	230/44
17.	Waubaushene TS	230/44

APPENDIX B. SOUTH GEORGIAN BAY-MUSKOKA REGION - TRANSMISSION LINES

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	E20/E21S	Essa TS	Stayner TS	230
2.	E26/E27	Essa TS	Parry Sound TS	230
3.	M6E/M7E	Essa TS	Minden TS	230
4.	D1M/D2M	Minden TS	Des Joachims TS	230
5.	D3M/D4M	Minden TS	Des Joachims TS	230
6.	M80B/M81B	Minden TS	Brown Hill TS	230
7.	E3B/E4B	Essa TS	Barrie TS	115
8.	S2S	Stayner TS	Owen Sound TS	115

APPENDIX C. SOUTH GEORGIAN BAY-MUSKOKA REGION - DISTRIBUTORS

Sr. No.	Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX
2.	Alectra Utilities	TX/DX
3.	InnPower	DX
4.	Orangeville Hydro	DX
5	Elexicon Energy	DX
6.	Lakeland Power	DX
7.	EPCOR Electricity Dist. Ontario Inc.	DX
8.	Newmarket-Tay Power Distribution Ltd.	DX
9.	Wasaga Distribution Inc.	DX

APPENDIX D. SOUTH GEORGIAN BAY-MUSKOKA REGION - STATIONS LOAD FORECAST

Summer Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	74.7	44	44	44	44	45	45	45	45	46	46	47	48	48	49	50	51	51	52	53	54	55
Alliston TS	T3/T4	112	100.8	76	80	83	86	90	93	91	91	91	92	92	93	93	93	93	93	94	94	94	94	94
Barrie TS	T1/T2	170	162.0	98	119	128	141	154	161	163	164	167	170	174	178	183	189	195	203	213	222	232	233	233
Beaverton TS	T3/T4	204	193.8	69	69	69	69	70	70	71	71	71	72	73	75	78	82	82	83	83	86	87	87	87
Bracebridge TS	T1	83	74.7	27	27	27	27	27	27	27	27	28	28	28	28	28	29	29	29	29	29	29	30	30
Everett TS	T1/T2	86	77.4	85	86	87	88	90	92	93	95	97	100	105	111	119	130	140	149	156	164	171	171	172
Lindsay TS	T1/T2	169	160.6	84	85	85	85	86	87	88	89	89	90	92	94	97	100	101	101	102	103	104	105	105
Meaford TS	T1/T2	55	52.3	33	33	33	33	33	34	34	34	34	35	37	38	38	38	38	38	39	39	39	40	40
Midhurst TS	T1/T2	171	163	150	151	153	154	156	157	159	160	162	162	163	166	167	169	170	171	173	174	175	176	176
Midhurst TS	T3/T4	166	149.4	123	107	111	115	118	122	125	129	133	136	140	144	151	156	160	163	167	171	175	176	176
Minden TS	T1/T2	58	52	44	44	44	44	44	45	45	45	46	46	46	47	47	48	48	52	52	53	53	53	53
Muskoka TS	T1/T2	179	170.1	113	114	113	113	114	115	116	117	125	125	126	127	130	132	133	134	135	136	137	137	137
Orangeville TS	T1/T2	113	101.7	49	49	52	53	53	54	55	55	56	57	59	60	62	62	63	64	65	65	66	67	67
Orangeville TS	T3/T4	170	161.5	90	91	97	98	99	100	102	103	104	106	110	111	114	116	117	119	120	122	123	124	124
Orillia TS	T1/T2	162	153.9	105	106	106	107	107	108	109	119	120	121	122	123	128	130	131	132	133	134	135	135	135
Parry Sound TS	T1/T2	113	101.7	45	46	45	47	48	50	50	51	54	54	55	55	56	56	56	57	57	58	58	58	59
Stayner TS	T3/T4	191	181.5	129	130	130	131	133	135	136	138	140	143	145	147	150	152	159	161	163	166	168	170	171
Wallace TS	T3/T4	54	48.6	36	36	36	36	36	36	36	36	36	37	37	37	37	38	38	38	38	38	38	39	40
Waubaushene TS	T5/T6	99	94.1	90	90	91	92	93	94	96	97	99	100	102	107	108	111	113	114	115	116	117	117	117

Winter Net Non-Coincident Load Forecast

Station	DESN ID	LTR (MVA)	LV Cap	LTR(MW)	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Alliston TS	T2	83	N	74.7	32	32	32	32	32	33	33	33	34	34	35	35	36	36	37	37	38	38	39	40	40
Alliston TS	T3/T4	128	N	115.2	80	69	74	78	81	85	88	87	86	87	87	87	88	88	88	88	88	89	89	89	88
Barrie TS	T1/T2	200	Y	190.0	74	88	97	109	119	127	127	129	131	133	136	140	144	149	153	160	168	176	184	185	186
Beaverton TS	T3/T4	224	Y	212.8	77	78	78	78	79	79	80	80	81	81	81	82	82	83	84	84	85	88	88	89	90
Bracebridge TS	T1	83	N	74.7	34	34	34	34	34	34	34	35	35	35	35	35	35	35	36	36	36	36	36	37	38
Everett TS	T1/T2	95	N	85.5	60	61	62	63	64	65	66	67	69	71	75	81	88	99	109	118	125	132	139	139	140
Lindsay TS	T1/T2	192	Y	182.4	92	93	94	94	95	96	97	98	98	99	100	101	102	102	103	104	105	105	107	106	107
Meaford TS	T1/T2	62	Y	58.9	43	44	44	44	44	44	44	45	45	45	52	52	53	53	53	54	54	54	54	55	56
Midhurst TS	T1/T2	194	Y	184.3	116	116	117	118	119	120	121	122	123	124	125	126	127	128	128	129	130	131	132	132	133
Midhurst TS	T3/T4	191	N	171.9	96	85	88	90	93	95	98	101	103	106	108	111	114	117	119	122	125	127	130	131	132
Minden TS	T1/T2	64	N	58	55	55	55	55	55	56	56	56	57	57	57	58	58	58	59	63	63	63	64	64	65
Muskoka TS	T1/T2	209	Y	198.6	146	146	146	147	148	150	151	151	158	159	160	161	162	163	164	165	166	167	168	168	169
Orangeville TS	T1/T2	133	N	119.7	42	42	45	46	46	46	47	47	47	48	52	52	55	55	56	56	56	57	57	58	58
Orangeville TS	T3/T4	200	Y	190.0	78	78	84	85	86	86	87	87	88	89	97	97	102	103	103	104	104	105	106	107	107
Orillia TS	T1/T2	184	Y	174.8	108	109	110	111	112	112	113	123	123	124	125	126	127	128	129	130	131	132	133	133	134
Parry Sound TS	T1/T2	133	N	119.7	59	60	60	62	64	65	66	66	69	69	70	70	71	71	72	73	73	74	74	75	76
Stayner TS	T3/T4	213	Y	202.4	135	136	137	138	139	141	142	144	145	147	148	150	152	154	167	169	171	173	175	176	178
Wallace TS	T3/T4	60	N	54.0	38	38	38	38	39	39	39	39	39	39	39	40	40	40	40	40	41	41	41	42	42
Waubaushene TS	T5/T6	109	Y	103.6	74	75	76	76	77	78	79	80	80	81	82	83	84	85	86	86	87	88	89	89	90

APPENDIX E. LIST OF ACRONYMS

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
GS	Generating Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DER	Distributed Energy Resource
DG	Distributed Generation
DSC	Distribution System Code
GS	Generating Station
GTA	Greater Toronto Area
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