Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

EXHIBIT 2
RATE BASE AND CAPITAL

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2 Rate Base and Capital

2.1 Rate Base

2.1.1 Overview

This Exhibit provides a detailed explanation of Welland Hydro-Electric System Corp.'s ("WHESC") historical and projected Rate Base from 2017 Board Approved amounts to 2024 Bridge Year and 2025 Test Year. WHESC has prepared this Exhibit in accordance with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications ("the Filing Requirements"), issued on December 15, 2022. This is in accordance with the OEB's letter dated April 11, 2024, whereby the OEB states that it will not issue an updated version of Chapters 1, 2 and 5 for the purposes of 2025 rates and that the current Filing Requirements for 2024 rates will be used for 2025 rate application.

In accordance with the Filing Requirements, WHESC has calculated its 2025 rate base as an average of the projected opening and closing balances for gross fixed assets and accumulated depreciation, plus a Working Capital Allowance ("WCA") equal to 7.5% of the sum of WHESC's projected cost of power and controllable expenses. Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements.

For the purposes of this Application, capital assets include Property, Plant and Equipment ("PP&E") and intangible assets that are in-service and enable WHESC to distribute electricity to its customers. WHESC distinguishes between capital purchases and in-service additions through Construction Work in Progress ("CWIP"). Capital purchases are added to Rate Base and depreciation commences when they become in-service assets and move out of CWIP, as application. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting, community relations, and administration and general expenses.

Table 2-1 below summarizes WHESC's historical rate base calculation from 2017 Board Approved to the proposed 2025 Test Year. The 2024 Bridge Year and 2025 Test Year reflect projected amounts, and 2017 to 2023 reflect actual results. WHESC's proposed 2025 Test Year rate base is $46,072,961, an increase of $12,407,793, or 37%, from the 2017 Board Approved rate base of $33,665,168. This increase in rate base is primarily attributable to an increase in the average net book value of capital assets in the amount of $12,533,004, offset by a net decrease in working capital from the 2017 Cost of Service ("COS") application in the amount of $1,669,466.

Table 2-1: Summary of Rate Base

Description	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Gross Fixed Assets Opening Balance	60,061,122	60,076,227	61,761,845	63,513,224	66,525,782	68,659,138	71,741,776	75,146,376	78,690,992	82,482,689
Gross Fixed Assets Closing Balance	62,093,917	61,761,845	63,513,224	66,525,782	68,659,138	71,741,776	75,146,376	78,690,992	82,399,979	87,298,102
Average Gross Fixed Assets	**61,077,520**	**60,919,036**	**62,637,534**	**65,019,503**	**67,592,460**	**70,200,457**	**73,444,076**	**76,918,684**	**80,545,486**	**84,890,396**
Accumulated Depreciation Opening Balance	30,927,737	30,928,494	31,797,087	33,045,389	34,235,843	34,728,457	36,345,789	38,094,006	39,955,800	41,909,721
Accumulated Depreciation Closing Balance	32,223,368	31,797,087	33,045,389	34,235,843	34,728,457	36,345,789	38,094,006	39,955,800	41,873,880	43,801,128
Average Accumulated Depreciation	**31,575,553**	**31,362,790**	**32,421,238**	**33,640,616**	**34,482,150**	**35,537,123**	**37,219,897**	**39,024,903**	**40,914,840**	**42,855,424**
Average Net Book Value	**29,501,967**	**29,556,245**	**30,216,297**	**31,378,887**	**33,110,310**	**34,663,334**	**36,224,179**	**37,893,781**	**39,630,646**	**42,034,971**
Working Capital	55,509,328	49,340,353	49,364,782	51,453,946	58,643,847	52,039,816	52,941,130	51,852,250	52,542,277	53,839,862
Working Capital Allowance (%)	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**4,163,200**	**3,700,526**	**3,702,359**	**3,859,046**	**4,398,288**	**3,902,986**	**3,970,585**	**3,888,919**	**3,940,671**	**4,037,990**
Rate Base	**33,665,168**	**33,256,772**	**33,918,655**	**35,237,933**	**37,508,599**	**38,566,321**	**40,194,763**	**41,782,700**	**43,571,317**	**46,072,961**

The 2025 opening balance of gross assets and accumulated depreciation includes an adjustment of $82,710 and $35,841 respectively, which represents the 2025 net book value of an investment in meters categorized as “Meter Inside Settlement Timeframe” (“MIST”) meters in 2018 that was previously recorded in Account 1557. For additional information related to this adjustment see Exhibit 9 of this application.

Table 2-2 below presents the change in the closing gross asset and accumulated depreciation balances, excluding CWIP, from the 2024 Bridge Year to the Opening 2025 Test Year.

Table 2-2: Total Gross Assets and Accumulated Depreciation

Total Assets (excluding CWIP)	Cost	Accumulated Depreciation
2025 Opening Balance	82,482,690	41,873,880
2024 Closing Balance	82,399,980	41,909,721
Difference	82,710	- 35,841

Table 2-3 below presents the change in Account 1860, meters from the closing 2024 Bridge Year balance to the opening 2025 Test Year balance. The change in the total Gross Asset and Accumulated Depreciation balance, as seen in Table 2-2 above is solely related to the investment in MIST Meters in 2018.

Table 2-3: Account 1860 Gross Asset & Accumulated Depreciation

Account 1860	Cost	Accumulated Depreciation
2025 Opening Balance	3,973,374	3,015,424
2024 Closing Balance	3,890,664	2,979,583
Difference	82,710	35,841

Table 2-4 calculates the adjustment required to opening Cost and Accumulated Depreciation for Account 1860 in the 2025 Test Year to account for the 2018 investment in MIST Meters.

Table 2-4: MIST Meter NBV Calculation

MIST Meters	Cost	Depreciation
2018	82,710	2,757
2019		5,514
2020		5,514
2021		5,514
2022		5,514
2023		5,514
2024		5,514
Total	82,710	35,841
Net Book Value		46,869

Table 2-5 below summarizes WHESC's historical WCA from 2017 Board Approved, 2017 to 2023 Actual, and the proposed 2024 Bridge Year and 2025 Test Year. WHESC's proposed 2025 Test Year WCA is $4,037,990 which represents a 3% decrease from 2017 OEB Approved WCA. Further details about WHESC's WCA are provided in Section 2.5.1 of this Exhibit.

Table 2-5: Summary of Working Capital Allowance

Description	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Operations	1,498,740	1,492,815	1,311,161	1,330,026	1,529,537	1,738,879	1,659,436	1,815,317	1,649,749	2,035,874
Maintenance	1,815,576	1,885,768	2,086,551	2,270,810	1,990,642	1,922,813	2,107,765	2,010,190	2,525,383	2,669,176
Billing and Collecting	1,467,344	1,428,794	1,399,519	1,327,067	1,500,139	1,393,265	1,491,435	1,474,496	1,640,375	1,765,877
Community Relations	144,123	149,386	169,206	153,684	63,668	41,182	53,290	59,435	66,867	69,133
Administrative and General Expenses	1,861,960	1,797,550	1,816,145	1,840,781	1,706,537	1,662,859	1,757,534	1,865,676	2,183,405	2,257,849
Donations - Leap	12,257	12,000	13,500	13,500	29,311	25,454	14,035	13,156	25,000	25,750
Cost of Power	48,709,328	42,574,040	42,568,699	44,518,077	51,824,013	45,255,363	45,857,634	44,613,980	44,451,498	45,016,203
Working Capital	**55,509,328**	**49,340,353**	**49,364,782**	**51,453,946**	**58,643,847**	**52,039,816**	**52,941,130**	**51,852,250**	**52,542,277**	**53,839,862**
Working Capital %	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**4,163,200**	**3,700,526**	**3,702,359**	**3,859,046**	**4,398,288**	**3,902,986**	**3,970,585**	**3,888,919**	**3,940,671**	**4,037,990**

2.1.2 Variance Analysis of Rate Base

The following Table 2-6 demonstrates WHESC's rate base variance from the 2025 Test Year compared to 2017 Board Approved.

Table 2-6: Rate Base Variance

Rate Base Calculation	2017 Board Approved	2025 Test Year	Variance	Variance %
Gross Fixed Assets Opening Balance	60,061,122	82,482,689	22,421,567	
Gross Fixed Assets Closing Balance	62,093,917	87,298,102	25,204,185	
Average Gross Fixed Assets	**61,077,520**	**84,890,396**	**23,812,876**	**39%**
Accumulated Depreciation Opening Balance	30,927,737	41,909,721	10,981,984	
Accumulated Depreciation Closing Balance	32,223,368	43,801,128	11,577,760	
Average Accumulated Depreciation	**31,575,553**	**42,855,424**	**11,279,872**	**36%**
Average Net Book Value	**29,501,967**	**42,034,971**	**12,533,004**	**42%**
Working Capital	55,509,328	53,839,862	-1,669,466	
Working Capital Allowance (%)	7.5%	7.5%	7.5%	
Working Capital Allowance	**4,163,200**	**4,037,990**	**-125,210**	**-3%**
Rate Base	**33,665,167**	**46,072,961**	**12,407,794**	**37%**

Working Capital Allowance	2017 Board Approved	2025 Test Year	Variance	Variance %
Controllable expenses	6,800,000	8,823,658	2,023,658	30%
Cost of Power	48,709,328	45,016,203	-3,693,125	-8%
Working Capital	**55,509,328**	**53,839,862**	**-1,669,466**	**-3%**
Working Capital %	7.5%	7.5%	7.5%	100%
Working Capital Allowance	**4,163,200**	**4,037,990**	**-125,210**	**-3%**

The variance between the 2025 Test Year and the 2017 Board Approved rate base is primarily due to an increase in the average net book value of fixed assets in the amount of $12,407,794. This is slightly offset by a $125,210 reduction in WCA. The increase in controllable expenses during this period is offset by a larger decrease in cost of power expense, resulting in an overall WCA reduction of 3%. Further details of WHESC’s fixed asset additions can be found in Section 2.2.2 of this Exhibit. Details related to WHESC’s controllable expenses can be found in Exhibit 4, and details of WHESC’s cost of power expenses can be found in Section 2.5.1.2 of this Exhibit.

Table 2-7 below outlines WHESC’s year-over-year rate base variances.

Table 2-7: Rate Base Year-over-year Variance

Description	2017 Actual vs. 2017 Board Approved	2018 Actual vs. 2017 Actual	2019 Actual vs. 2018 Actual	2020 Actual vs. 2019 Actual	2021 Actual vs. 2020 Actual	2022 Actual vs. 2021 Actual	2023 Actual vs. 2022 Actual	2024 Bridge Year vs. 2023 Actual	2025 Test Year vs. 2024 Bridge Year
Gross Fixed Assets Opening Balance	15,105	1,685,618	1,751,379	3,012,558	2,133,357	3,082,638	3,404,600	3,544,616	3,791,697
Gross Fixed Assets Closing Balance	-332,072	1,751,379	3,012,558	2,133,357	3,082,638	3,404,600	3,544,616	3,708,987	4,898,123
Average Gross Fixed Assets	**-158,484**	**1,718,499**	**2,381,969**	**2,572,957**	**2,607,997**	**3,243,619**	**3,474,608**	**3,626,802**	**4,344,910**
Accumulated Depreciation Opening Balance	757	868,593	1,248,301	1,190,454	492,615	1,617,331	1,748,217	1,861,794	1,953,921
Accumulated Depreciation Closing Balance	-426,281	1,248,301	1,190,454	492,615	1,617,331	1,748,217	1,861,794	1,918,080	1,927,248
Average Accumulated Depreciation	**-212,762**	**1,058,447**	**1,219,378**	**841,534**	**1,054,973**	**1,682,774**	**1,805,006**	**1,889,937**	**1,940,585**
Average Net Book Value	**54,278**	**660,051**	**1,162,591**	**1,731,423**	**1,553,024**	**1,560,844**	**1,669,602**	**1,736,865**	**2,404,325**
Working Capital	-6,168,975	24,429	2,089,164	7,189,901	-6,604,031	901,314	-1,088,879	690,027	1,297,585
Working Capital Allowance (%)	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**-462,673**	**1,832**	**156,687**	**539,243**	**-495,302**	**67,599**	**-81,666**	**51,752**	**97,319**
Rate Base	**-408,395**	**661,884**	**1,319,278**	**2,270,665**	**1,057,722**	**1,628,443**	**1,587,936**	**1,788,617**	**2,501,644**

The year-over-year material variances in rate base are discussed in the balance of this section.

2025 Test Year vs 2024 Bridge Year

The 2025 Test Year rate base is forecast to be $2,501,644 higher than the 2024 Bridge Year. The increase is primarily related to an increase in the forecasted average net book value of assets. The increase is also attributed to an increase in WCA due to an increase in forecasted controllable costs and cost of power.

2024 Bridge Year vs. 2023 Actual

The 2024 Bridge Year rate base is forecast to be $1,788,617 higher than 2023 Actuals. The increase is primarily related to an increase in the forecasted average net book value of assets. It is also attributed to higher forecasted controllable costs that are partially offset by a decrease in forecasted cost of power expense.

2023 Actual vs. 2022 Actual

The total rate base for 2023 Actual was $1,587,937 higher than 2022 Actual. The increase is primarily due to a higher net book value of assets, offset by a decrease in working capital. The decrease in working capital is primarily due to a reduction in cost of power expense offset by an increase in controllable costs.

2021 Actual vs. 2020 Actual

The total rate base for 2021 Actual was $1,057,723 higher than 2020 Actual due to a higher net book value of assets, partially offset by a decrease in working capital due to lower cost of power expense.

2020 Actual vs. 2019 Actual

The total Rate Base for 2020 was $2,270,666 higher than 2019 Actual due to a higher net book value of assets, as well as an increase in working capital due to higher cost of power expense.

<u>2019 Actual vs. 2018 Actual</u>

The total Rate Base for 2019 Actual was $1,319,279 higher than 2018 Actual primarily due to a higher net book value of assets.

<u>2018 Actual vs. 2017 Actual</u>

The total Rate Base for 2018 Actual was $661,885 higher almost entirely due to a higher net book value of assets.

<u>2017 Actual vs. 2017 Board Approved</u>

The total Rate Base for 2017 Actual was $408,394 lower than 2017 Board Approved Rate Base primarily related to predicted cost of power expense lower than predicted.

2.2 Fixed Asset Continuity Schedule

WHESC has included Fixed Asset Continuity Schedules, consistent with Board Appendix 2-BA, as Appendix 2-C to this Exhibit.

2.2.1 Breakdown by Function

WHESC has categorized its gross assets into four primary categories, consistent with the Uniform System of Accounts ("USoA"), as described below:

<u>Intangible Plant</u>
Assets include USoA range of accounts 1611 to 1612 and include assets such as computer software.

<u>Distribution Plant</u>
Assets include USoA range of accounts 1805 to 1860 and include assets such as substation equipment, poles, wires, transformers and meters.

<u>General Plant</u>
Assets include USoA range of accounts 1905 to 1980 and include assets such as buildings, computer hardware, transportation equipment, and tools.

<u>Contribution and Grants</u>
Assets include USoA account 1995/2440 and includes all contributions in aid of capital that WHESC has received or forecasted to be received as per the Distribution System Code ("DSC").

Table 2-8 below summarizes WHESC's gross asset balances by the categories described above for 2017 Board Approved, 2017 to 2023 Actual, the 2024 Bridge Year and 2025 Test Year.

Table 2-8: Historical Gross Assets by Category

Description	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Intangible Plant	1,037,292	1,163,843	1,163,843	1,546,156	936,434	948,215	956,069	991,519	991,519	991,519
Distribution Plant	54,966,373	54,663,344	56,394,953	58,551,015	62,359,984	65,579,543	69,263,576	73,756,771	78,491,151	83,034,328
General Plant	6,833,690	6,689,111	6,879,399	7,710,846	7,781,732	8,360,707	8,720,541	8,969,112	9,664,182	10,993,277
Contributions & Grants	- 743,436	- 754,453	- 924,971	- 1,282,235	- 2,419,011	- 3,146,689	- 3,793,809	- 5,026,409	- 6,746,872	- 7,721,021
Total Gross Assets	**62,093,919**	**61,761,845**	**63,513,224**	**66,525,782**	**68,659,139**	**71,741,776**	**75,146,376**	**78,690,993**	**82,399,979**	**87,298,102**

Year-over-year variances are summarized in Section 2.2.2 below.

2.2.2 Gross Assets Variance Analysis

This section explains the year-over-year variances by USoA account. WHESC has used a materiality threshold of $68,000. Variances greater than materiality are identified by the highlighted cells in each of the tables in this section. All balances shown are as at year-end. There is no capitalized interest or capitalized overhead cost applicable for the period 2017 through to the 2025 Test Year.

2.2.2.1 2017 Actual vs 2017 Board Approved

WHESC had a decrease in Gross Assets of -$332,074 from the 2017 Board Approved to 2017 Actual.

Table 2-9: Gross Assets - 2017 Actual vs. 2017 Board Approved

OEB Account	Description	2017 OEB Approved	2017 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	966,996	1,093,547	126,551
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**1,037,292**	**1,163,843**	**126,551**
Distribution Plant				
1805	Land	158,686	158,686	0
1808	Buildings	96,568	96,568	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	4,661,261	4,224,978	-436,283
1830	Poles, Towers & Fixtures	10,639,682	10,591,918	-47,764
1835	Overhead Conductors & Devices	13,877,667	13,943,246	65,579
1840	Underground Conduit	1,767,830	2,005,139	237,309
1845	Underground Conductors & Devices	11,716,604	11,680,592	-36,012
1850	Line Transformers	7,613,277	7,536,316	-76,961
1855	Services (Overhead & Underground)	895,562	866,282	-29,280
1860	Meters	3,071,877	3,092,261	20,384
	Subtotal	**54,966,373**	**54,663,344**	**-303,029**
General Plant				
1908	Buildings & Fixtures	2,735,551	2,728,781	-6,770
1915	Office Furniture & Equipment (10 years)	90,446	90,445	-1
1920	Computer Equipment - Hardware	249,823	248,633	-1,190
1930	Transportation Equipment	2,178,152	1,997,038	-181,114
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	105,814	151,808	45,994
1945	Measurement & Testing Equipment	20,451	20,451	0
1955	Communications Equipment	298,231	298,231	0
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	809,964	808,464	-1,500
	Subtotal	**6,833,690**	**6,689,111**	**-144,579**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-743,436	-754,453	-11,017
	Subtotal	**-743,436**	**-754,453**	**-11,017**
	Total PP&E	**62,093,919**	**61,761,845**	**-332,074**

Intangible Plant

Account 1611 – Computer Software

2017 Actual vs. 2017 Board Approved ($126,551)

The increase in 2017 Actual compared to 2017 Board approved is due to the unplanned purchase of CIS licensing based on the decision to move IT services from a hosted solution to on-premise. This was to manage ongoing operating costs and cybersecurity posture.

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

2017 Actual vs. 2017 Board Approved (-$436,283)

2017 Board Approved capital included $170,000 in additions that were deferred to subsequent years. Disposals in 2017 resulted in a decrease in gross asset value due to the retirement of failed assets. These included a failed power transformer and high voltage switchgear at Municipal Station (MS) 5 and failed high voltage cabling at MS6. There was also the retirement of a mobile substation at end-of-life.

Account 1840 – Underground Conduit

2017 Actual vs. 2017 Board Approved ($237,309)

In 2017, underground cable systems were installed in subdivisions and for station egress that resulted in additions of $237,000 above plan. This was largely due to increased voltage conversion requirements in 4.16kV underground supplied subdivisions.

Account 1850 – Line Transformers

2017 Actual vs. 2017 Board Approved ($-76,961)

The 2017 actual additions were less than the OEB approved amount by $77,000 due to transformation requirements on rebuild and voltage conversion projects lower than planned.

General Plant

Account 1930 – Transportation Equipment

2017 Actual vs. 2017 Board Approved ($ -181,114)

The variance between 2017 Actual and 2017 Board Approved is due to the sale of a fully depreciated bucket truck.

2.2.2.2 2018 Actual vs 2017 Actual

WHESC had an increase in Gross Assets of $1,751,380 from 2017 Actual to 2018 Actual.

Table 2-10: Gross Assets - 2018 Actual vs. 2017 Actual

OEB Account	Description	2017 Actual	2018 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	1,093,547	1,093,547	0
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**1,163,843**	**1,163,843**	**0**
Distribution Plant				
1805	Land	158,686	158,686	0
1808	Buildings	96,568	96,568	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	4,224,978	4,453,159	228,181
1830	Poles, Towers & Fixtures	10,591,918	11,299,371	707,453
1835	Overhead Conductors & Devices	13,943,246	14,024,494	81,248
1840	Underground Conduit	2,005,139	2,078,178	73,039
1845	Underground Conductors & Devices	11,680,592	11,922,832	242,240
1850	Line Transformers	7,536,316	7,797,133	260,817
1855	Services (Overhead & Underground)	866,282	914,252	47,970
1860	Meters	3,092,261	3,182,921	90,660
	Subtotal	**54,663,344**	**56,394,953**	**1,731,609**
General Plant				
1908	Buildings & Fixtures	2,728,781	2,836,585	107,804
1915	Office Furniture & Equipment (10 years)	90,445	90,445	0
1920	Computer Equipment - Hardware	248,633	248,633	0
1930	Transportation Equipment	1,997,038	2,007,700	10,662
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	151,808	148,867	-2,941
1945	Measurement & Testing Equipment	20,451	40,825	20,374
1955	Communications Equipment	298,231	298,231	0
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	808,464	862,853	54,389
	Subtotal	**6,689,111**	**6,879,399**	**190,288**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-754,453	-924,971	-170,518
	Subtotal	**-754,453**	**-924,971**	**-170,518**
	Total PP&E	**61,761,845**	**63,513,224**	**1,751,380**

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

2018 Actual vs. 2017 Actual ($228,181)

Contributing to this variance is approximately $82,000 in additions to replace failed primary cabling at MS6 in 2018. Additionally, a backup transformer was installed at MS12 to provide redundancy for an otherwise islanded substation, resulting in an addition of $89,000. MS1 relay and RTU replacements contributed approximately $25,000 to the year-over-year variance. MS7 egress cable replacements contributed approximately $32,000 to the variance.

Account 1830 – Poles, Towers & Fixtures

2018 Actual vs. 2017 Actual ($707,453)

The increase is a result of WHESC's pole replacement program which increased spending by approximately $526,000. In addition, end of life pole replacements occurred in association with rebuild and voltage conversion projects at a cost of approximately $182,000. The increase in pole replacement program spending in 2018 and moving forward in the forecast period was reflective of requirements identified through the 2018 Asset Condition Assessment ("ACA"). The updated ACA in 2023 continues to demonstrate the need for individual pole replacements, where aggregation into a rebuild project is not warranted given the balance of investment drivers. Further details regarding WHESC's pole inspection and replacement program can be found in the DSP, Sections 5.3.2.2.1, 5.3.3.2.4, and 5.4.1.2.2.

Account 1835 – Overhead Conductors & Devices

2018 Actual vs. 2017 Actual ($81,248)

In 2018, additional overhead primary conductor and equipment associated with line rebuilds and voltage conversions were the basis for the $81,000 variance.

Account 1840 – Underground Conduit

2018 Actual vs. 2017 Actual ($73,039)

In 2018, approximately $73,000 of conduit systems were installed in underground residential subdivisions, associated with rebuild and voltage conversion projects.

Account 1845 – Underground Conductors & Devices

2018 Actual vs. 2017 Actual ($242,240)

In 2018, approximately $147,000 of underground cable was installed in new subdivisions. Approximately $95,000 of underground primary cable was installed in conjunction with residential subdivision rebuild and voltage conversion projects.

Account 1850 – Line Transformers

2018 Actual vs. 2017 Actual ($260,817)

In 2018, there was the addition of $43,000 in transformation installed in residential subdivisions. Approximately $126,000 of transformer installations were associated with rebuild and voltage conversion projects. There was approximately $104,000 of transformation replacements associated with the pole replacement program and from reactive requirements. Transformers added for new commercial developments accounted for approximately $30,000. These amounts are offset by approximately $42,000 of disposals due to scrap transformers.

Account 1860 - Meters

2018 Actual vs. 2017 Actual ($90,660)

The increase in 2018 is primarily related to new meters acquired to support compliance sampling of the smart meter population and new service connections.

General Plant

Account 1908 – Buildings & Fixtures

2018 Actual vs. 2017 Actual ($107,804)

The increased expenditure in 2018 is related to parking lot rehabilitation at our service center at a cost of $107,804.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2018 Actual vs. 2017 Actual ($-170,518)

Capital contributions in 2018 included approximately $145,000 for new residential subdivision developments. Additional capital contributions of approximately $25,000 were received in relation to new service connections.

2.2.2.3 2019 Actual vs 2018 Actual

WHESC had an increase in Gross Assets of $3,012,558 from 2018 Actual to 2019 Actual.

Table 2-11: Gross Assets - 2019 Actual vs. 2018 Actual

OEB Account	Description	2018 Actual	2019 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	1,093,547	1,475,860	382,313
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**1,163,843**	**1,546,156**	**382,313**
Distribution Plant				
1805	Land	158,686	155,686	-3,000
1808	Buildings	96,568	96,568	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	4,453,159	4,577,922	124,763
1830	Poles, Towers & Fixtures	11,299,371	12,016,224	716,853
1835	Overhead Conductors & Devices	14,024,494	14,148,927	124,433
1840	Underground Conduit	2,078,178	2,146,009	67,831
1845	Underground Conductors & Devices	11,922,832	12,300,164	377,332
1850	Line Transformers	7,797,133	8,496,973	699,840
1855	Services (Overhead & Underground)	914,252	928,479	14,227
1860	Meters	3,182,921	3,216,703	33,782
	Subtotal	**56,394,953**	**58,551,015**	**2,156,061**
General Plant				
1908	Buildings & Fixtures	2,836,585	3,182,230	345,645
1915	Office Furniture & Equipment (10 years)	90,445	18,163	-72,282
1920	Computer Equipment - Hardware	248,633	396,926	148,293
1930	Transportation Equipment	2,007,700	2,313,210	305,510
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	148,867	169,930	21,063
1945	Measurement & Testing Equipment	40,825	40,825	0
1955	Communications Equipment	298,231	305,800	7,568
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	862,853	938,504	75,651
	Subtotal	**6,879,399**	**7,710,846**	**831,447**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-924,971	-1,282,235	-357,264
	Subtotal	**-924,971**	**-1,282,235**	**-357,264**
	Total PP&E	**63,513,224**	**66,525,782**	**3,012,558**

Intangible Plant

Account 1611 – Computer Software

2019 Actual vs. 2018 Actual ($382,313)

The capital expenditure in 2019 is related to the implementation of new financial system software and the related licensing at a cost of approximately $268,000. Also included is additional licensing that was required in the continuation of the transitioning of IT services from a hosted solution to on premise. This included physical hardware for WHESC's virtualized server environment at approximately $78K. Also included was the transition from the hosted estimating software solution to an on premise Quadra implementation at approximately $36K.

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

2019 Actual vs. 2018 Actual ($124,763)

In 2019, MS12 high voltage switch and relay upgrades were completed at a cost of approximately $40,000. The low voltage switchgear and cabling was replaced at MS8 at a cost of approximately $129,000. The HV switchgear at MS10 failed and was replaced with HV cabling at a cost of approximately $46K. There was approximately $90,000 in disposals related to replacement of assets at MS8 and MS10.

Account 1830 – Poles, Towers & Fixtures

2019 Actual vs. 2018 Actual ($716,853)

The increase is a result of WHESC's pole replacement program which increased spending by approximately $406,000. In addition, end of life pole replacements occurred in association with rebuild and voltage conversion projects at a cost of approximately $311,000.

Account 1835 – Overhead Conductors & Devices

2019 Actual vs. 2018 Actual ($124,433)

In 2019, additional overhead primary conductor and equipment associated with line rebuilds and voltage conversions were the basis for the $124,000 variance.

Account 1845 – Underground Conductors & Devices

2019 Actual vs. 2018 Actual ($377,332)

In 2019, approximately $236,000 of underground cable was installed in new residential subdivisions. Approximately $142,000 of underground primary cable was installed in conjunction with subdivision rebuild and voltage conversion projects.

Account 1850 – Line Transformers

2019 Actual vs. 2018 Actual ($699,840)

In 2019, there was the addition of $69,000 in transformation installed in residential subdivisions. Approximately $451,000 of transformer installations were associated with rebuild and voltage conversion projects. There was approximately $183,000 of transformation replacements associated with the pole replacement program and from reactive requirements. Transformers added for new commercial developments accounted for approximately $30,000. These amounts are offset by approximately $42,000 of disposals due to scrap transformers.

General Plant

Account 1908 – Buildings & Fixtures

2019 Actual vs. 2018 Actual ($345,645)

Capital spending included additional remediation of the service center parking lot at a cost of $81,000, replacement of HVAC units at a cost of $25,600, and replacement of the service center roof at a cost of $239,000.

Account 1915 – Office Furniture & Equipment

2019 Actual vs. 2018 Actual ($-72,282)

The decrease in asset value for this account is related to the disposal of furniture and equipment that was fully depreciated and no longer in use.

Account 1920 – Computer Equipment

2019 Actual vs. 2018 Actual ($148,293)

The increase in 2019 is related to the purchase of server hardware that was required as part of migration of systems from a hosted environment to an on premise solution.

Account 1930 – Transportation Equipment

2019 Actual vs. 2018 Actual ($305,510)

The increase in 2019 is related to the purchase of a light vehicle at a cost of $41,000, a reel trailer at a cost of $58,000 and a digger truck to replace an end-of-life unit from 1990 at a cost of $360,000. The cost of these additions was offset by the sale of end-of-life vehicles with a combined cost of $153,500.

Account 1980 – System Supervisor Equipment

2019 Actual vs. 2018 Actual ($75,651)

The increase in 2019 is related to installation of an automated device on the M17 circuit as part of WHESC's grid modernization plan. Protection system upgrades were also performed at MS10, completed by internal staff.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2019 Actual vs. 2018 Actual ($-357,264)

Capital contributions in 2019 included approximately $267,000 for new residential subdivision developments. Additional capital contributions of approximately $91,000 were received in relation to new service connections.

2.2.2.4 2020 Actual vs 2019 Actual

WHESC had an increase in Gross Assets of $2,133,357 from 2019 Actual to 2020 Actual.

Table 2-12: Gross Assets - 2020 Actual vs. 2019 Actual

OEB Account	Description	2019 Actual	2020 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	1,475,860	866,138	-609,722
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**1,546,156**	**936,434**	**-609,722**
Distribution Plant				
1805	Land	155,686	155,686	0
1808	Buildings	96,568	96,568	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	4,577,922	4,816,542	238,620
1830	Poles, Towers & Fixtures	12,016,224	12,631,392	615,168
1835	Overhead Conductors & Devices	14,148,927	14,606,758	457,830
1840	Underground Conduit	2,146,009	2,484,331	338,322
1845	Underground Conductors & Devices	12,300,164	13,522,260	1,222,095
1850	Line Transformers	8,496,973	9,368,352	871,379
1855	Services (Overhead & Underground)	928,479	955,134	26,655
1860	Meters	3,216,703	3,255,602	38,899
	Subtotal	**58,551,015**	**62,359,984**	**3,808,969**
General Plant				
1908	Buildings & Fixtures	3,182,230	3,191,281	9,052
1915	Office Furniture & Equipment (10 years)	18,163	18,163	0
1920	Computer Equipment - Hardware	396,926	285,882	-111,044
1930	Transportation Equipment	2,313,210	2,344,565	31,355
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	169,930	174,330	4,400
1945	Measurement & Testing Equipment	40,825	40,825	0
1955	Communications Equipment	305,800	303,435	-2,365
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	938,504	1,077,993	139,489
	Subtotal	**7,710,846**	**7,781,732**	**70,886**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-1,282,235	-2,419,011	-1,136,776
	Subtotal	**-1,282,235**	**-2,419,011**	**-1,136,776**
	Total PP&E	**66,525,782**	**68,659,139**	**2,133,357**

Intangible Plant

Account 1611 – Computer Software

2020 Actual vs. 2019 Actual (-$609,722)

The net change in 2020 gross assets is the result of capital additions, offset by the write-off of end-of-use assets that are no longer in service, which included legacy CIS and financial system software. Additions included licensing in support of the transition of IT services from a hosted solution to on-premise, including a purchased license and upgrade related to our document storage system in the amount of $125,000.

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

2020 Actual vs. 2019 Actual ($238,620)

The MS9 power transformer and low voltage switchgear along with station primary cabling was replaced resulting in approximately $310,000 in additions. This was offset by disposals of replaced equipment at MS9 of approximately $71,000.

Account 1830 – Poles, Towers & Fixtures

2020 Actual vs. 2019 Actual ($615,168)

The increase is a result of WHESC's pole replacement program which increased spending by approximately $263,000. In addition, end of life pole replacements occurred in association with rebuild and voltage conversion projects at a cost of approximately $353,000.

Account 1835 – Overhead Conductors & Devices

2020 Actual vs. 2019 Actual ($457,830)

In 2020, additional overhead primary conductor and equipment associated with line rebuilds and voltage conversions were the basis for the $458,000 variance. Major 3 phase overhead line installations accounted for approximately $313,000 of the additions. Details of WHESC's Overhead Line Renewal program can be found in the DSP, Section 5.4.1.2.2.

Account 1840 – Underground Conduit

2020 Actual vs. 2019 Actual ($338,322)

In 2020, approximately $255,000 of conduit systems were installed in the Roal Oak residential subdivision rebuild project. An additional $46,000 of conduit systems were installed related to an overhead rebuild that required the replacement of connected underground primary cable. The remaining $37,000 was related to conduit systems installed as part of three smaller underground rebuild projects.

Account 1845 – Underground Conductors & Devices

2020 Actual vs. 2019 Actual ($1,222,095)

In 2020, approximately $1,028,000 of underground cable and switchgear were installed in new residential subdivisions. Approximately $195,000 of underground primary cable was installed in conjunction with rebuild and voltage conversion projects.

Account 1850 – Line Transformers

2020 Actual vs. 2019 Actual ($871,379)

In 2020, there was the addition of $484,000 in transformation installed in residential subdivisions and new developments. Approximately $293,000 of transformer installations were associated with rebuild and voltage conversion projects. There was approximately $127,000 of transformation replacements associated with the pole replacement program and from reactive requirements. These amounts are offset by approximately $32,000 of disposals due to scrap transformers.

General Plant

Account 1920 – Computer Equipment

2020 Actual vs. 2019 Actual ($-111,044)

The change in gross asset value in is related to miscellaneous computer replacements, offset by the write-off of end-of-life assets that are no longer in use.

Account 1980 – System Supervisor Equipment

2020 Actual vs. 2019 Actual ($139,489)

The increase in 2020 is related to the purchase of SCADA controlled switches in the amount of $102,000, protection system replacements in the amount of $22,600 and a remote terminal unit for a SCADA operated switch in the amount of $14,000.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2020 Actual vs. 2019 Actual ($-1,136,776)

Capital contributions in 2020 included approximately $1,003,000 for new residential subdivision developments. Additional capital contributions of $134,000 were received in relation to new service connections.

2.2.2.5 2021 Actual vs 2020 Actual

WHESC had an increase in Gross Assets of $3,082,638 from 2020 Actual to 2021 Actual.

Table 2-13: Gross Assets - 2021 Actual vs. 2020 Actual

OEB Account	Description	2020 Actual	2021 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	866,138	877,919	11,781
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**936,434**	**948,215**	**11,781**
Distribution Plant				
1805	Land	155,686	155,686	0
1808	Buildings	96,568	101,761	5,193
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	4,816,542	4,795,989	-20,553
1830	Poles, Towers & Fixtures	12,631,392	13,669,354	1,037,962
1835	Overhead Conductors & Devices	14,606,758	15,209,031	602,273
1840	Underground Conduit	2,484,331	2,633,160	148,829
1845	Underground Conductors & Devices	13,522,260	14,266,689	744,429
1850	Line Transformers	9,368,352	9,967,659	599,307
1855	Services (Overhead & Underground)	955,134	946,477	-8,657
1860	Meters	3,255,602	3,366,379	110,777
	Subtotal	**62,359,984**	**65,579,543**	**3,219,560**
General Plant				
1908	Buildings & Fixtures	3,191,281	3,191,281	0
1915	Office Furniture & Equipment (10 years)	18,163	18,163	0
1920	Computer Equipment - Hardware	285,882	276,633	-9,249
1930	Transportation Equipment	2,344,565	2,676,765	332,200
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	174,330	174,330	0
1945	Measurement & Testing Equipment	40,825	44,587	3,762
1955	Communications Equipment	303,435	315,435	12,000
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	1,077,993	1,318,254	240,261
	Subtotal	**7,781,732**	**8,360,707**	**578,974**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-2,419,011	-3,146,689	-727,677
	Subtotal	**-2,419,011**	**-3,146,689**	**-727,677**
	Total PP&E	**68,659,139**	**71,741,776**	**3,082,638**

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

2021 Actual vs. 2020 Actual ($1,037,962)

The increase is a result of WHESC's pole replacement program which increased spending by approximately $311,000. In addition, end of life pole replacements occurred in association with rebuild and voltage conversion projects at a cost of approximately $663,000. Pole installation work associated with line relocations also occurred at a cost of approximately $64,000.

Account 1835 – Overhead Conductors & Devices

2021 Actual vs. 2020 Actual ($602,273)

In 2021, additional overhead primary conductor and equipment associated with line rebuilds and voltage conversions were the basis for $561,000 of additions. Approximately $41,000 of the additions in 2021 were attributed to line relocation projects.

Account 1840 – Underground Conduit

2021 Actual vs. 2020 Actual ($148,829)

In 2020, approximately $141,000 of conduit systems were installed in the Bridlewood/Chapel Hill residential subdivision rebuild and voltage conversion project. The balance was related to an underground relocation project and small underground rebuilds.

Account 1845 – Underground Conductors & Devices

2021 Actual vs. 2020 Actual ($744,429)

In 2021, approximately $565,000 of underground cable and switchgear were installed in new residential subdivisions. Approximately $105,000 of underground primary cable was installed in conjunction with rebuild and voltage conversion projects. In circuit relocation projects, approximately $75,000 of underground primary cable and switchgear was installed.

Account 1850 – Line Transformers

2021 Actual vs. 2020 Actual ($599,307)

In 2021, there was the addition of $189,000 in transformation installed in residential subdivisions and new developments. Approximately $237,000 of transformer installations were associated with rebuild and voltage conversion projects. There was approximately $185,000 of transformation replacements associated with the pole replacement program and from reactive requirements. These amounts are offset by approximately $12,000 of disposals due to scrap transformers.

Account 1860 - Meters

2021 Actual vs. 2020 Actual ($110,777)

In 2021, additions are reflective of the increase in customer connections and meters acquired to support reverification requirements and end-of-life replacements.

General Plant

Account 1930 – Transportation Equipment

2021 Actual vs. 2020 Actual ($332,200)

The increase in 2021 is primarily attributed to the purchase of a bucket truck in the amount of $349,000. An existing bucket truck was overhauled at a cost of $12,000. These additions were offset by the sale of a light duty pickup truck with a cost of $29,000.

Account 1980 – System Supervisor Equipment

2021 Actual vs. 2020 Actual ($240,261)

The increase in 2021 is related to the deployment of three SCADA controlled switches at a cost of approximately $226,000 and remote fault sensing equipment at a cost of $14,000.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

<u>2021 Actual vs. 2020 Actual ($-727,677)</u>

Capital contributions in 2021 included approximately $503,000 for new residential subdivision developments. Additional capital contributions of approximately $27,000 were received in relation to new service connections. Contributions for circuit relocations were approximately $198,000 in 2021.

2.2.2.6 2022 Actual vs 2021 Actual

WHESC had an increase in Gross Assets of $3,404,600 from 2021 Actual to 2022 Actual.

Table 2-14: Gross Assets - 2022 Actual vs. 2021 Actual

OEB Account	Description	2021 Actual	2022 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	877,919	885,773	7,854
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**948,215**	**956,069**	**7,854**
Distribution Plant				
1805	Land	155,686	155,686	0
1808	Buildings	101,761	101,761	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	4,795,989	5,588,101	792,112
1830	Poles, Towers & Fixtures	13,669,354	14,857,323	1,187,970
1835	Overhead Conductors & Devices	15,209,031	15,535,229	326,198
1840	Underground Conduit	2,633,160	2,696,595	63,435
1845	Underground Conductors & Devices	14,266,689	14,737,203	470,514
1850	Line Transformers	9,967,659	10,686,620	718,962
1855	Services (Overhead & Underground)	946,477	987,731	41,253
1860	Meters	3,366,379	3,449,968	83,589
	Subtotal	**65,579,543**	**69,263,576**	**3,684,033**
General Plant				
1908	Buildings & Fixtures	3,191,281	3,191,281	0
1915	Office Furniture & Equipment (10 years)	18,163	18,163	0
1920	Computer Equipment - Hardware	276,633	285,619	8,986
1930	Transportation Equipment	2,676,765	2,680,294	3,528
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	174,330	174,330	0
1945	Measurement & Testing Equipment	44,587	44,587	0
1955	Communications Equipment	315,435	368,173	52,738
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	1,318,254	1,612,836	294,582
	Subtotal	**8,360,707**	**8,720,541**	**359,834**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-3,146,689	-3,793,809	-647,121
	Subtotal	**-3,146,689**	**-3,793,809**	**-647,121**
	Total PP&E	**71,741,776**	**75,146,376**	**3,404,600**

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

2022 Actual vs. 2021 Actual ($792,112)

In 2022, MS3 was completely rebuilt resulting in additions of approximately $627,000. The low voltage reclosers at MS11 were replaced at a cost of $79,000. The T2 transformer was upgraded at MS5 based on capacity requirements, costing $87,000.

Account 1830 – Poles, Towers & Fixtures

2022 Actual vs. 2021 Actual ($1,187,970)

The increase is a result of WHESC's pole replacement program which increased spending by approximately $240,000. In addition, end of life pole replacements occurred in association with rebuild and voltage conversion projects at a cost of approximately $770,000. Pole installation work associated with line relocations and system expansions also occurred at a cost of approximately $178,000.

Account 1835 – Overhead Conductors & Devices

2022 Actual vs. 2021 Actual ($326,198)

In 2022, additional overhead primary conductor and equipment associated with line rebuilds and voltage conversions were the basis for $212,000 of additions. Approximately $114,000 of the additions in 2022 were attributed to line relocations and system expansions

Account 1845 – Underground Conductors & Devices

2022 Actual vs. 2021 Actual ($470,514)

In 2022, approximately $343,000 of underground cable and switchgear were installed in new residential subdivisions. Approximately $94,000 of underground primary cable was installed in conjunction with rebuild and voltage conversion projects. A switchgear replacement accounts for $34,000 of the variance.

Account 1850 – Line Transformers

2022 Actual vs. 2021 Actual ($718,962)

In 2022, there was the addition of $281,000 in transformation installed in residential subdivisions and new developments. Approximately $39,000 of transformer installations were associated with rebuild and voltage conversion projects. There was approximately $61,000 of transformation replacements associated with the pole replacement program and from reactive requirements. Due to post-COVID procurement issues, increased transformer deliveries occurred in 2022 causing an increase in inventory at a cost of approximately $346,000. These amounts are offset by approximately $8,000 of disposals due to scrap transformers.

Account 1860 - Meters

2022 Actual vs. 2021 Actual ($83,589)

The new meter additions in 2022 were a result of new connection growth and meters acquired to support reverification requirements and end-of-life replacements.

General Plant

Account 1980 – System Supervisor Equipment

2022 Actual vs. 2021 Actual ($294,582)

The increase in 2022 is related to the deployment of three SCADA controlled switches at a cost of $233,000. SCADA switch remote terminal unit upgrades were also completed at a cost of approximately $61,000.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2022 Actual vs. 2021 Actual ($-647,121)

Capital contributions in 2022 included approximately $194,000 for new residential subdivision developments. Additional capital contributions of approximately $112,000 were received in relation to new service connections. Contributions for circuit relocations and line expansions were approximately $341,000 in 2022.

2.2.2.7 2023 Actual vs 2022 Actual

WHESC had an increase in Gross Assets of $3,544,616 from 2022 Actual to 2023 Actual.

Table 2-15: Gross Assets - 2023 Actual vs. 2022 Actual

OEB Account	Description	2022 Actual	2023 Actual	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	885,773	921,223	35,450
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**956,069**	**991,519**	**35,450**
Distribution Plant				
1805	Land	155,686	155,686	0
1808	Buildings	101,761	101,761	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	5,588,101	5,629,316	41,215
1830	Poles, Towers & Fixtures	14,857,323	16,240,086	1,382,763
1835	Overhead Conductors & Devices	15,535,229	15,974,536	439,307
1840	Underground Conduit	2,696,595	2,955,004	258,409
1845	Underground Conductors & Devices	14,737,203	15,888,300	1,151,098
1850	Line Transformers	10,686,620	11,394,231	707,611
1855	Services (Overhead & Underground)	987,731	1,209,827	222,096
1860	Meters	3,449,968	3,740,664	290,696
	Subtotal	**69,263,576**	**73,756,771**	**4,493,195**
General Plant				
1908	Buildings & Fixtures	3,191,281	3,227,685	36,404
1915	Office Furniture & Equipment (10 years)	18,163	18,163	0
1920	Computer Equipment - Hardware	285,619	319,659	34,040
1930	Transportation Equipment	2,680,294	2,726,693	46,400
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	174,330	174,330	0
1945	Measurement & Testing Equipment	44,587	44,587	0
1955	Communications Equipment	368,173	368,173	0
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	1,612,836	1,744,563	131,727
	Subtotal	**8,720,541**	**8,969,112**	**248,571**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-3,793,809	-5,026,409	-1,232,600
	Subtotal	**-3,793,809**	**-5,026,409**	**-1,232,600**
	Total PP&E	**75,146,376**	**78,690,993**	**3,544,616**

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

<u>2023 Actual vs. 2022 Actual ($1,382,763)</u>

The increase is a result of WHESC's pole replacement program which increased spending by approximately $351,000. In addition, end of life pole replacements occurred in association with rebuild and voltage conversion projects at a cost of approximately $973,000. Pole installation work associated with system expansions also occurred at a cost of approximately $59,000.

<u>Account 1835 – Overhead Conductors & Devices</u>

<u>2023 Actual vs. 2022 Actual ($439,307)</u>

In 2023, additional overhead primary conductor and equipment associated with line rebuilds and voltage conversions were the basis for $390,000 of additions. Approximately $49,000 of the additions in 2023 were attributed to line relocations and system expansions

<u>Account 1840 – Underground Conduit</u>

<u>2023 Actual vs. 2022 Actual ($258,409)</u>

In 2023, approximately $252,000 of conduit systems were installed in the Sherwood Forest residential subdivision rebuild and voltage conversion project. The balance was related to small underground rebuild projects.

<u>Account 1845 – Underground Conductors & Devices</u>

<u>2023 Actual vs. 2022 Actual ($1,151,098)</u>

In 2023, approximately $948,000 of underground cable and switchgear were installed in new residential subdivisions. Approximately $154,000 of underground primary cable was installed in conjunction with rebuild and voltage conversion projects. In circuit expansion projects, approximately $49,000 of underground primary cable was installed.

<u>Account 1850 – Line Transformers</u>

<u>2023 Actual vs. 2022 Actual ($707,611)</u>

In 2023, there was the addition of $518,000 in transformation installed in residential subdivisions and new developments. Approximately $99,000 of transformer installations were associated with rebuild and voltage conversion projects. There was approximately $95,000 of transformation replacements associated with the pole replacement program and from reactive requirements. These amounts are offset by approximately $4,000 of disposals due to scrap transformers.

Account 1855 - Services

2023 Actual vs. 2022 Actual ($222,096)

In 2023, the variance in new service additions relates to an increase in new connection volume in that year. This combined with an increase in service connection material costs contributed to the variance.

Account 1860 - Meters

2023 Actual vs. 2022 Actual ($290,696)

The cost of net meter additions in 2023 increased by approximately $290,000 as WHESC increased stock levels due to post-COVID procurement issues. Meters received in 2023 were based on purchase orders issued in 2021 and 2022 due to manufacturing lead time delays. WHESC also increased meter inventory based on the increase in new connections in 2022 and 2023.

General Plant

Account 1980 – System Supervisor Equipment

2023 Actual vs. 2022 Actual ($131,727)

The increase in 2023 is related to the deployment of a SCADA controlled switch and replacement of an RTU at a cost of approximately $110,000. Additional remote fault sensing equipment was also deployed at three locations on the distribution system.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2023 Actual vs. 2022 Actual ($-1,232,600)

Capital contributions in 2023 included approximately $852,000 for new residential subdivision developments. Additional capital contributions of approximately $152,000 were received in relation to new service connections. Contributions for line expansions were approximately $228,000 in 2023.

2.2.2.8 2024 Bridge Year vs 2023 Actual

WHESC has an increase in Gross Assets of $3,708,987 from 2023 Actual to the 2024 Bridge Year.

Table 2-16: Gross Assets - 2024 Bridge Year vs. 2023 Actual

OEB Account	Description	2023 Actual	2024 Bridge Year	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	921,223	921,223	0
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**991,519**	**991,519**	**0**
Distribution Plant				
1805	Land	155,686	155,686	0
1808	Buildings	101,761	101,761	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	5,629,316	5,629,316	0
1830	Poles, Towers & Fixtures	16,240,086	17,849,106	1,609,020
1835	Overhead Conductors & Devices	15,974,536	16,825,366	850,830
1840	Underground Conduit	2,955,004	2,982,504	27,500
1845	Underground Conductors & Devices	15,888,300	17,155,550	1,267,250
1850	Line Transformers	11,394,231	12,179,011	784,780
1855	Services (Overhead & Underground)	1,209,827	1,254,827	45,000
1860	Meters	3,740,664	3,890,664	150,000
	Subtotal	**73,756,771**	**78,491,151**	**4,734,380**
General Plant				
1908	Buildings & Fixtures	3,227,685	3,617,315	389,630
1915	Office Furniture & Equipment (10 years)	18,163	38,163	20,000
1920	Computer Equipment - Hardware	319,659	347,299	27,640
1930	Transportation Equipment	2,726,693	2,791,693	65,000
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	174,330	184,630	10,300
1945	Measurement & Testing Equipment	44,587	67,087	22,500
1955	Communications Equipment	368,173	368,173	0
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	1,744,563	1,904,563	160,000
	Subtotal	**8,969,112**	**9,664,182**	**695,070**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-5,026,409	-6,746,872	-1,720,463
	Subtotal	**-5,026,409**	**-6,746,872**	**-1,720,463**
	Total PP&E	**78,690,993**	**82,399,979**	**3,708,987**

Distribution Plant

Account 1830 – Poles, Towers & Fixtures

2024 Bridge Year vs. 2023 Actual ($1,609,020)

The pole replacement program in 2024 results in $150,000 of planned additions. Planned rebuild and voltage conversion projects in 2024 include end of life pole replacements at a cost of $900,000. Additionally, system expansions result in pole additions at a cost of $559,000.

Account 1835 – Overhead Conductors & Devices

2024 Bridge Year vs. 2023 Actual ($850,830)

The overhead line rebuilds and voltage conversions in 2024 result in $611,000 of planned additions. Additionally, system expansions result in overhead line and equipment additions at a cost of $240,000.

Account 1845 – Underground Conductors & Devices

2024 Bridge Year vs. 2023 Actual ($1,267,250)

In 2024, approximately $827,000 of underground cable and switchgear additions are projected in residential subdivisions. Approximately $190,000 of underground cable and switchgear installations are planned in association with rebuild and voltage conversion projects. Also planned are $250,000 in pad-mounted switchgear replacements in 2024.

Account 1850 – Line Transformers

2024 Bridge Year vs. 2023 Actual ($784,780)

For 2024, planned transformer installation additions in new residential subdivisions and developments cost approximately $509,000. Transformer installations planned in association with rebuild and conversion projects are forecasted at $196,000. Transformer installation additions related to the pole replacement program and reactive work are estimated at $80,000.

Account 1860 - Meters

2024 Bridge Year vs. 2023 Actual ($150,000)

Meter additions in 2024 are based on cost experience in the prior year, projected new connection requirements, and procurement activities initiated in 2023 to manage significant manufacturing and delivery delays.

General Plant

Account 1908 – Buildings & Fixtures

2024 Bridge Year vs. 2023 Actual ($389,630)

Facility improvement spending is based on WHESC's building condition assessment that was completed in support of the DSP. Planned expenditures include minor upgrades to the exterior of the building at an approximate cost of $70,000, paving at an approximate cost of $220,000, and minor renovations in the operations area of the building at a cost of approximately $100,000.

Account 1980 – System Supervisor Equipment

2024 Bridge Year vs. 2023 Actual ($160,000)

2024 planned additions include the deployment of two automated switching devices on the 27.6kV distribution system. These devices are incorporated into the 27.6kV system protection scheme and are remote operable via SCADA. Also included in this spend is the cost of deploying fault sensing devices at three locations on the 27.6 kV distribution system. These devices provide load, fault, and disturbance information to WHESC system control operators via SCADA.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2024 Bridge Year vs. 2023 Actual ($-1,720,463)

Capital contributions forecasted for 2024 include $142,863 in relation to new connections and $803,000 for new residential subdivision developments. Approximately $774,600 of planned contributions are related to line expansion projects.

2.2.2.9 2025 Test Year vs 2024 Bridge Year

WHESC has an increase in Gross Assets of $4,898,123 from the 2024 Bridge Year to the 2025 Test Year.

Table 2-17: Gross Assets - 2025 Test Year vs. 2024 Bridge Year

OEB Account	Description	2024 Bridge Year	2025 Test Year	Variance
Intangible Plant				
1611	Computer Software (Formally known as Account 1925)	921,223	921,223	0
1612	Land Rights (Formally known as Account 1906)	70,296	70,296	0
	Subtotal	**991,519**	**991,519**	**0**
Distribution Plant				
1805	Land	155,686	155,686	0
1808	Buildings	101,761	101,761	0
1815	Transformer Station Equipment >50 kV	467,359	467,359	0
1820	Distribution Station Equipment <50 kV	5,629,316	5,989,316	360,000
1830	Poles, Towers & Fixtures	17,849,106	18,780,493	931,387
1835	Overhead Conductors & Devices	16,825,366	17,187,560	362,194
1840	Underground Conduit	2,982,504	3,065,004	82,500
1845	Underground Conductors & Devices	17,155,550	18,619,050	1,463,500
1850	Line Transformers	12,179,011	13,239,047	1,060,036
1855	Services (Overhead & Underground)	1,254,827	1,301,177	46,350
1860	Meters	3,890,664	4,127,874	237,210
	Subtotal	**78,491,151**	**83,034,328**	**4,543,177**
General Plant				
1908	Buildings & Fixtures	3,617,315	3,742,315	125,000
1915	Office Furniture & Equipment (10 years)	38,163	88,163	50,000
1920	Computer Equipment - Hardware	347,299	487,299	140,000
1930	Transportation Equipment	2,791,693	3,453,129	661,436
1935	Stores Equipment	30,023	30,023	0
1940	Tools, Shop & Garage Equipment	184,630	195,239	10,609
1945	Measurement & Testing Equipment	67,087	167,087	100,000
1955	Communications Equipment	368,173	368,173	0
1960	Miscellaneous Equipment	315,235	315,235	0
1980	System Supervisor Equipment	1,904,563	2,146,613	242,050
	Subtotal	**9,664,182**	**10,993,277**	**1,329,095**
Contributions & Grants				
1995/2440	Contributions & Grants/Deferred Revenue	-6,746,872	-7,721,021	-974,149
	Subtotal	**-6,746,872**	**-7,721,021**	**-974,149**
	Total PP&E	**82,399,979**	**87,298,102**	**4,898,123**

Distribution Plant

Account 1820 – Distribution Station Equipment <50 kV

2025 Test Year vs. 2024 Bridge Year ($360,000)

Planned expenditure in 2025 is to replace an end-of-life power transformer at MS5 based on condition assessment. MS7 protection system upgrades are also planned in 2025 to replace end of life relay and RTU systems.

Account 1830 – Poles, Towers & Fixtures

2025 Test Year vs. 2024 Bridge Year ($931,387)

The pole replacement program in 2025 results in approximately $302,000 of planned additions. Planned rebuild and voltage conversion projects for 2025 include end of life pole replacements at a cost of $629,000.

Account 1835 – Overhead Conductors & Devices

2025 Test Year vs. 2024 Bridge Year ($362,194)

The planned overhead line rebuilds and voltage conversions in 2025 contribute $362,000 to additions in the test year.

Account 1840 – Underground Conduit

2025 Test Year vs. 2024 Bridge Year ($82,500)

In 2025, approximately $82,500 of conduit system installation is required in association with the Dover/Dunkirk area rebuild and voltage conversion.

Account 1845 – Underground Conductors & Devices

2025 Test Year vs. 2024 Bridge Year ($1,463,500)

In 2025, approximately $302,500 of primary cable and switchgear installations are required in association with the Dover/Dunkirk area rebuild and voltage conversion. Approximately $852,000 of underground cable and switchgear additions are projected in residential subdivisions. The pad-mounted switchgear replacement program requires the addition of approximately $258,000. The balance of the variance is associated with forecasted reactive underground renewal requirements.

Account 1850 – Line Transformers

2025 Test Year vs. 2024 Bridge Year ($1,060,036)

For 2025, planned transformer installation additions in new residential subdivisions and developments cost approximately $524,000. Transformer installations planned in association with rebuild and conversion projects are forecasted at $375,000. Transformer installation additions related to the pole replacement program and reactive work are estimated at $161,000.

Account 1860 - Meters

2025 Test Year vs. 2024 Bridge Year ($237,210)

Meter additions projected for 2025 are based on meters that will be received and capitalized due to procurement initiated in 2024. These are to support new connections, re-verification requirements, and end-of-life replacements. The 2025 opening balance of this account was adjusted to include an $82,710 investment in MIST meters in 2018 that was previously recorded in Account 1557. For additional information related to this adjustment see Exhibit 9 of this application.

General Plant

Account 1908 – Buildings & Fixtures

2025 Test Year vs. 2024 Bridge Year ($125,000)

Planned additions in 2025 relate to required minor renovations in the operations area resulting from WHESC's building condition assessment.

Account 1920 – Computer Equipment

2025 Test Year vs. 2024 Bridge Year ($140,000)

Planned expenditures in 2025 are to replace systems that are at, or approaching, end-of-life based on vendor support terms.

Account 1930 – Transportation Equipment

2025 Test Year vs. 2024 Bridge Year ($661,436)

The proposed additions in WHESC's 2025 Test Year are largely driven by asset condition and are based on the results of a fleet assessment conducted in support of the DSP. The additions include the purchase of a light vehicle, a reel trailer, and a bucket truck.

Account 1945 – Measurement & Testing Equipment

2025 Test Year vs. 2024 Bridge Year ($100,000)

Expenditures in 2025 include meter test equipment and equipment supporting maintenance activities in lines and substations.

Account 1980 – System Supervisor Equipment

2025 Test Year vs. 2024 Bridge Year ($242,050)

2025 expenditures include the deployment of three automated switching devices on the 27.6kV distribution system. These devices are incorporated into the 27.6kV system protection scheme and are remote operable via SCADA. Also included in this spend is the cost of deploying fault sensing devices at three locations on the 27.6 kV distribution system. These devices provide load, fault, and disturbance information to WHESC system control operators via SCADA.

Contributions & Grants

Account 1995/2440 – Contributions & Grants/Deferred Revenue

2025 Test Year vs. 2024 Bridge Year ($-974,149)

Capital contributions for 2025 include $147,149 in relation to forecasted new connections and $827,000 for new residential subdivision developments.

2.4 Depreciation, Amortization and Depletion

2.4.1 Depreciation Policy

WHESC groups fixed assets in accordance with MIFRS standards with significant components of PP&E being depreciated separately. Depreciation is recognized on a straight-line basis over the estimated useful life of each significant identifiable component of the asset. Land is not depreciated. Construction in progress assets are not depreciated until the project is complete and in service.

WHESC used the Typical Useful Life ("TUL") values provided in the Kinectrics Report as the basis for assigning the estimated service life to assets, as indicated in Chapter 2 Appendices 2-BB. WHESC is below the minimum range for one asset category, Primary TR XLPE Cables in Duct included in USoA account 1845. The TUL for this cable has been set at 30 years versus the minimum of 35 contained in the Kinectrics report. Installation of this cable began in 2006 at WHESC. WHESC used its experience related to certain categories such as 1830 Poles to set lives higher than the minimum life per the Kinectrics report. Based on experience relating to underground cables, WHESC took a conservative approach and set the useful lives for this type of primary cabling to just under the minimum value in the Kinectrics report. WHESC used 30 years in determining depreciation expense in the Board Approved 2017 Cost of Service Rate Application (EB-2016-0110) for this asset classification. No change is proposed for this asset category in this Application.

WHESC's depreciation rates have changed for two asset categories since its 2017 Cost of Service application (EB-2016-0110). For Station DC System Battery Bank and DC System Chargers, WHESC previously used an estimated service life of five years. As of this filing, all assets in these categories are fully depreciated. WHESC has changed to using an estimated service life of 10 years for Station DC System Battery Banks, and 20 years for Station DC System Chargers. In both cases, the estimated service life is now within the TUL range of the Kinectrics Report.

WHESC has completed Chapter 2 Appendices 2-C, included as Appendix 2-D to this Exhibit. The deprecation calculated in Appendix 2-C reconciles with the balances in the Fixed Asset Continuity Schedules, included as Appendix 2-B to this Exhibit. Depreciation of an asset begins in the year when it is used and useful. In the first year of service, depreciation is calculated using the half-year rule. Depreciation of an asset ceases when the asset is retired from active use, sold or is fully depreciated. WHESC calculates a full year of depreciation in the year in which an asset is retired from active use, sold or becomes fully depreciated.

The following table provides a summary of WHESC's depreciation by year.

Table 2-18: Depreciation Expense 2017-2025

OEB Account	Description	Last Rebasing Year (2017 Actuals)	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Actuals	2023 Actuals	2024 Bridge Year	2025 Test Year
1611	Computer Software (Formally known as Account 1925)	104,090	145,613	140,956	130,541	160,781	147,885	139,560	104,874	39,838
1612	Land Rights (Formally known as Account 1906)	640	640	640	640	640	640	640	640	640
1805	Land	-	-	-	-	-	-	-	-	-
1808	Buildings	1,236	1,236	1,236	1,238	1,495	1,495	1,495	1,495	1,495
1815	Transformer Station Equipment >50 kV	14,857	14,857	14,857	14,858	14,857	14,857	14,857	14,857	13,523
1820	Distribution Station Equipment <50 kV	89,556	87,030	94,568	99,872	105,275	116,167	128,722	128,368	133,622
1830	Poles, Towers & Fixtures	194,473	207,697	221,940	235,258	251,791	274,049	299,758	329,675	355,079
1835	Overhead Conductors & Devices	143,136	145,808	147,865	153,686	164,288	173,573	181,228	194,129	206,260
1840	Underground Conduit	34,211	39,564	40,973	45,034	49,906	52,029	55,247	58,106	59,206
1845	Underground Conductors & Devices	188,584	196,687	207,014	225,100	256,363	274,923	300,647	337,946	381,640
1850	Line Transformers	129,138	137,726	150,938	169,746	187,872	204,439	222,280	240,988	264,048
1855	Services (Overhead & Underground)	20,339	21,072	21,850	22,361	22,586	22,993	26,285	29,624	30,766
1860	Meters	204,560	209,611	214,906	215,594	221,987	227,299	240,495	208,734	130,162
1908	Buildings & Fixtures	67,598	70,622	84,429	96,219	95,992	93,897	93,015	104,053	115,442
1915	Office Furniture & Equipment (10 years)	3,896	2,243	1,816	1,816	1,530	692	70	1,000	4,500
1920	Computer Equipment - Hardware	53,089	43,468	35,988	39,038	42,586	46,220	50,501	42,929	41,179
1930	Transportation Equipment	109,892	125,550	147,329	163,127	173,353	193,291	184,468	189,091	203,597
1935	Stores Equipment	-	-	-	-	-	-	-	-	-
1940	Tools, Shop & Garage Equipment	8,128	9,235	8,875	9,457	9,530	9,530	9,530	9,938	10,876
1945	Measurement & Testing Equipment	771	1,708	2,726	2,726	2,814	2,619	2,414	3,539	8,580
1955	Communications Equipment	28,678	16,613	17,370	17,418	3,379	8,346	12,112	11,592	11,072
1960	Miscellaneous Equipment	11,128	11,128	11,128	11,128	11,128	11,128	11,128	11,128	11,128
1980	System Supervisor Equipment	43,771	29,203	31,055	29,253	31,570	44,941	55,672	63,123	73,343
1995/2440	Contributions & Grants/Deferred Revenue	-22,644	-25,552	-33,417	-56,123	-84,260	-102,401	-127,938	-167,749	-204,589
Total Depreciation Expense		1,429,125	1,491,760	1,565,041	1,627,988	1,725,463	1,818,611	1,902,187	1,918,080	1,891,407
Deferred Revenue									167,749	204,589
Net Depreciation		**1,429,125**	**1,491,760**	**1,565,041**	**1,627,988**	**1,725,463**	**1,818,611**	**1,902,187**	**2,085,829**	**2,095,996**

A summary of the annual variances calculated is summarized in Table 2-19 below.

Table 2-19: Depreciation Variance Summary

OEB Account	Description	2017 vs 2018 Actuals	2018 vs 2019 Actuals	2019 vs 2020 Actuals	2020 vs 2021 Actuals	2021 vs 2022 Actuals	2022 vs 2023 Actuals	2023 Actuals vs 2024 Bridge	2024 Bridge vs 2025 Test
1611	Computer Software (Formally known as Account 1925)	41,523	-4,657	-10,415	30,240	-12,896	-8,325	-34,686	-65,036
1612	Land Rights (Formally known as Account 1906)	-	-	-	-	-	-	0	-
1805	Land	-	-	-	-	-	-	-	-
1808	Buildings	-	-	3	257	-0	-	0	-
1815	Transformer Station Equipment >50 kV	-	-	1	-1	-	-	-0	-1,333
1820	Distribution Station Equipment <50 kV	-2,526	7,538	5,304	5,403	10,892	12,555	-354	5,253
1830	Poles, Towers & Fixtures	13,223	14,243	13,318	16,533	22,258	25,709	29,918	25,404
1835	Overhead Conductors & Devices	2,672	2,057	5,821	10,602	9,285	7,655	12,901	12,130
1840	Underground Conduit	5,353	1,409	4,061	4,872	2,123	3,218	2,859	1,100
1845	Underground Conductors & Devices	8,104	10,326	18,086	31,264	18,560	25,724	37,299	43,694
1850	Line Transformers	8,589	13,211	18,808	18,126	16,567	17,841	18,708	23,060
1855	Services (Overhead & Underground)	734	777	512	224	407	3,292	3,339	1,142
1860	Meters	5,050	5,296	687	6,393	5,312	13,196	-31,761	-78,571
1908	Buildings & Fixtures	3,024	13,806	11,790	-226	-2,095	-882	11,038	11,389
1915	Office Furniture & Equipment (10 years)	-1,653	-427	-	-287	-838	-621	930	3,500
1920	Computer Equipment - Hardware	-9,621	-7,480	3,051	3,547	3,634	4,281	-7,572	-1,751
1930	Transportation Equipment	15,658	21,779	15,797	10,227	19,938	-8,823	4,623	14,506
1935	Stores Equipment	-	-	-	-	-	-	-	-
1940	Tools, Shop & Garage Equipment	1,107	-360	582	72	-0	-	408	938
1945	Measurement & Testing Equipment	937	1,019	-	88	-196	-205	1,125	5,042
1955	Communications Equipment	-12,064	757	47	-14,039	4,967	3,767	-520	-520
1960	Miscellaneous Equipment	-	-	-	-	-	-	-	-
1980	System Supervisor Equipment	-14,568	1,852	-1,801	2,316	13,371	10,732	7,450	10,220
1995/2440	Contributions & Grants/Deferred Revenue	-2,908	-7,864	-22,706	-28,137	-18,141	-25,537	-39,811	-36,840
Total Depreciation Expense		62,635	73,281	62,947	97,475	93,148	83,576	15,893	-26,672
Deferred Revenue		-	-	-	-	-	-	167,749	36,840
Net Depreciation		**62,635**	**73,281**	**62,947**	**97,475**	**93,148**	**83,576**	**183,642**	**10,168**

Beginning in 2024, WHESC records Depreciation on capital contributions to Account 2440 Deferred revenue rather than Account 1995 Capital Contributions. As a result of the reallocation, there is a $167,749 variance in Depreciation in Account 2440 Deferred revenue in the 2024 Bridge Year. This is related to allocation only, as the variance in depreciation on contributed capital is $-39,811 which is equal to 2024 Bridge Year Depreciation of $-167,749 less 2023 Actual Depreciation of $-127,938.

The decrease is depreciation in Account 1860 Meters is related to meters that became fully depreciated in 2024. The Depreciation recorded for these meters was $88,721 in 2024. This decrease was partially offset by an increase in depreciation in 2025 in the amount of $10,150 to account for a full year depreciation of meters purchased in 2024, and a half year depreciation for meters purchased in 2025.

The net depreciation calculation difference on the remaining accounts by account basis was below the materiality threshold.

2.4.2 Asset Retirement Obligations

WHESC has not recorded any Asset Retirement Obligations in Fixed Assets.

2.5 Allowance for Working Capital

In accordance with the Filing Requirements and a letter dated June 3, 2015, the OEB provided an update to the OEB's policy for the calculation of the allowance for working capital. The distributor may take one of two approaches for the calculation of its allowance for working capital:

1. Use the default allowance of 7.5% of the sum of Cost of Power ("COP") and OM&A; or
2. File a lead/lag study

WHESC has used the default allowance of 7.5% for the 2025 Test Year in this application. As such, WHESC did not conduct a lead/lag study.

2.5.1 Working Capital Allowance

Table 2-20 below provides a summary of WHESC's Cost of Power and Controllable Expenses used to calculate working capital allowance for 2017 Board Approved, 2017 to 2023 Actual, 2024 Bridge Year and 2025 Test Year. WHESC is proposing a working capital allowance of $4,037,990 for its 2025 Test Year.

Table 2-20: Summary of Working Capital Allowance

Description	2017 Board Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Cost of Power Expenses	**48,709,328**	**42,574,040**	**42,568,699**	**44,518,077**	**51,824,013**	**45,255,363**	**45,857,634**	**44,613,980**	**44,451,498**	**45,016,203**
Controllable Expenses										
Distribution Expenses Operations	1,498,740	1,492,815	1,311,161	1,330,026	1,529,537	1,738,879	1,659,436	1,815,317	1,649,749	2,035,874
Distribution Expenses Maintenance	1,815,576	1,885,768	2,086,551	2,270,810	1,990,642	1,922,813	2,107,765	2,010,190	2,525,383	2,669,176
Billing and Collecting	1,467,344	1,428,794	1,399,519	1,327,067	1,500,139	1,393,265	1,491,435	1,474,496	1,640,375	1,765,877
Commuinty Relations	144,123	149,386	169,206	153,684	63,668	41,182	53,290	59,435	66,867	69,133
Administrative and General Expenses	1,861,960	1,797,550	1,816,145	1,840,781	1,706,537	1,662,859	1,757,534	1,865,676	2,183,405	2,257,849
Donations Leap	12,257	12,000	13,500	13,500	29,311	25,454	14,035	13,156	25,000	25,750
Total Controllable Expenses	**6,800,000**	**6,766,313**	**6,796,083**	**6,935,869**	**6,819,834**	**6,784,453**	**7,083,496**	**7,238,271**	**8,090,780**	**8,823,658**
Working Capital	**55,509,328**	**49,340,353**	**49,364,782**	**51,453,946**	**58,643,847**	**52,039,816**	**52,941,130**	**51,852,250**	**52,542,277**	**53,839,862**
Working Capital Allowance Rates	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**4,163,200**	**3,700,526**	**3,702,359**	**3,859,046**	**4,398,288**	**3,902,986**	**3,970,585**	**3,888,919**	**3,940,671**	**4,037,990**

2.5.1.1 Controllable Costs

WHESC's proposed WCA is based on Operations, Maintenance, Billing & Collecting, Community Relations and Administrative & General expenses. For additional information about WHESC's OM&A expenses, please refer to Exhibit 4 of this Application.

2.5.1.2 Cost of Power

WHESC has calculated its Cost of Power for the 2025 Test Year based on its 2025 load forecast outlined in Exhibit 3 of this Application. The components of WHESC's Cost of Power forecast are summarized in Table 2-21.

Table 2-21: 2025 Test Year COP

Description	2025 Test Year
4705 - Power Purchases	31,855,038
4707 - Global Adjustment	9,219,026
4708 - Charges-WMS	2,318,111
4714 - Charges-NW	4,708,818
4716 - Charges-CN	3,330,132
4751 - IESO SME	130,977
Misc A/R or A/P	-6,545,898
Total Cost of Power Expenses	**45,016,203**

Commodity Prices

In accordance with the Filing Requirements, the commodity price estimate used to calculate COP was determined in a way that bases the split between Regulated Price Plan ("RPP") and non-RPP customers on actual data and uses the most current RPP price. WHESC confirms that the impact of the most recent Ontario Electricity Rebate (19.3%) has been included in the calculation.

The RPP and non-RPP price was obtained from the Regulated Price Plan Price Report for the period of November 1, 2023 to October 31, 2024, published by the OEB on October 19, 2023. For the purposes of calculating the 2025 Test Year, WHESC has used an estimate of $0.11105 per kWh for RPP customers. For non-RPP Class B customers, WHESC has used an estimate of $0.10465 per kWh, which includes $0.03179 per kWh for the Wholesale Electricity Price and $0.07286 per kWh for Global Adjustment charges. For non-RPP Class A customers, WHESC has used an estimate of $0.06979 per kWh, which includes $0.03179 per kWh for the Wholesale Electricity Price and $.0380 per kWh for Global Adjustment charges based on WHESC's average of 2023 historical actual costs.

WHESC understands that the commodity charge will be updated to reflect any changes to commodity prices that may become available prior to approval of its Application.

<u>Table 2-22: Average RPP Supply Cost</u>

Table 3: Average RPP Supply Cost Forecast Summary

RPP Supply Cost Summary for the period from November 1, 2023 through October 31, 2024		$/MWh
Forecast Wholesale Electricity Price - Simple Average		$29.38
Load-Weighted Costs for RPP Consumers		
Wholesale Electricity Cost - RPP-Weighted		$31.79
Global Adjustment	+	$72.86
Adjustment to Clear Existing Variances	+	$5.40
Adjustment to Address Bias Towards Unfavourable Variance	+	$1.00
Average Supply Cost for RPP Consumers	=	**$111.05**

Source: Power Advisory

Regulatory Charges

The Wholesale Market Service ("WMS") Charges for the 2025 Test Year were calculated based on the OEB Decision and Rate Order issued on January 1, 2024 (EB-2023-0268). The Decision and Rate Order sets the Wholesale Market Service Rate (WMS) at $0.0045 per kWh, and the Rural or Remote Rate Protection (RRRP) at $0.0014 per kWh. These rates were applied to the forecasted power purchases for the 2025 Test Year.

Network and Connection Charges

Network and Connection charges were determined by using the RTSR rates calculated in Exhibit 8 applying these rates to the results of the 2025 load forecast. WHESC utilized the most recently approved Uniform Transmission Rates in this calculation. WHESC's proposed RTSR Charges are shown in Table 2-23 below:

Table 2-23: Proposed RTSR Charges

Description	Unit	Proposed Network	Proposed Connection
Residential	kWh	$ 0.0131	$ 0.0090
GS < 50	kWh	$ 0.0116	$ 0.0076
GS > 50	kW	$ 3.9201	$ 2.9744
Street Light	kW	$ 3.6621	$ 2.4470
Sentinel Light	kW	$ 3.6701	$ 2.4524
USL	kWh	$ 0.0116	$ 0.0076

Low Voltage Charges

WHESC does not incur low voltage charges from Hydro One.

Smart Meter Entity Charges

The Smart Meter Entity costs are calculated based on the rate of $0.42 per month for all Residential and General Service < 50 kW customers. This charge was approved by the Board on September 8, 2022 (EB-2022-0137) and is in effect until December 31, 2027, or as further directed by the Board.

Consumption

WHESC used the forecasted monthly purchases (kWh and peak kW) in the load forecast model described in Exhibit 3 to determine the 2025 Test Year Cost of Power.

The split between RPP and Non-RPP volumes for 2025 was determined using 2023 actual consumption by customer type (RPP and Non-RPP) and rate class.

Table 2-24 summarizes WHESC's calculation of its proposed 2025 Test Year Cost of Power used for its WCA.

Table 2-24: 2025 Proposed Cost of Power

		2025 Test Year	RPP		2025 Test Year	non-RPP		Total
Electricity Commodity	**Units**	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	193,532,100		21,491,740	1,690,203		53,732	
GS < 50	kWh	48,518,497		5,387,979	10,203,902		324,382	
GS > 50 (excluding WMP)	kWh	841,461		93,444	136,160,036		4,328,528	
WMP	kWh	0		-	2,743,349		-	
Street Light	kWh	0		-	1,540,002		48,957	
Sentinel Light	kWh	340,183		37,777	58,119		1,848	
USL	kWh	757,291		84,097	80,360		2,555	
SUB-TOTAL				27,095,038			4,760,000	$ 31,855,038

Global Adjustment non-RPP	**Units**							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential - Class B	kWh			0			123,148	
GS < 50 - Class B	kWh			0			743,456	
GS > 50 (excluding WMP) - Class B	kWh			0			6,387,363	
WMP - Class B	kWh			0			-	
Street Light - Class B	kWh			0			112,205	
Sentinel Light - Class B	kWh			0			4,235	
USL - Class B	kWh			0			5,855	
				0			-	
GS > 50 - Class A				0			1,842,764	
				0			-	
SUB-TOTAL				0			9,219,026	$ 9,219,026

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	193,532,100	0.0131	2,538,981	1,690,203	0.0131	22,174	
GS < 50	kWh	48,518,497	0.0116	561,003	10,203,902	0.0116	117,984	
GS > 50 (excluding WMP)	kW	1,867	3.9201	7,318	362,245	3.9201	1,420,028	
WMP	kW	-	-	-	5,093	3.9201	19,967	
Street Light	kW	-	3.6621	-	2,131	3.6621	7,805	
Sentinel Light	kW	901	3.6701	3,308	154	3.6701	564	
USL	kWh	757,291	0.0116	8,756	80,360	0.0116	929	
SUB-TOTAL				3,119,366			1,589,451	4,708,818

Transmission - Connection								
Class per Load Forecast							$	Total
Residential	kWh	193,532,100	0.0090	1,750,853	1,690,203	0.0090	15,291	
GS < 50	kWh	48,518,497	0.0076	369,108	10,203,902	0.0076	77,627	
GS > 50 (excluding WMP)	kW	1,867	2.9744	5,553	362,245	2.9744	1,077,444	
WMP	kW	-	2.9744	-	5,093	2.9744	15,150	
Street Light	kW	-	2.4470	-	4,147	2.4470	10,147	
Sentinel Light	kW	901	2.4524	2,210	154	2.4524	377	
USL	kWh	757,291	0.0076	5,761	80,360	0.0076	611	
SUB-TOTAL				2,133,484			1,196,647	3,330,132

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	193,532,100	0.0041	793,482	1,690,203	0.0041	6,930	
GS < 50	kWh	48,518,497	0.0041	198,926	10,203,902	0.0041	41,836	
GS > 50 (excluding WMP)	kWh	841,461	0.0041	3,450	136,160,036	0.0041	558,256	
WMP	kWh	-	0.0041	-	2,743,349	-	-	
Street Light	kWh	-	0.0041	-	1,540,002	0.0041	6,314	
Sentinel Light	kWh	340,183	0.0041	1,395	58,119	0.0041	238	
USL	kWh	757,291	0.0041	3,105	80,360	0.0041	329	
SUB-TOTAL				1,000,357			613,904	1,614,261
Class A CBR								
Class per Load Forecast							$	Total
Residential				-			-	
GS < 50				-			-	
GS > 50 (excluding WMP)	kWh			-	48,493,782	0.0003	14,548	
WMP				-			-	
Street Light				-			-	
Sentinel Light				-			-	
USL				-			-	
SUB-TOTAL				-			14,548	14,548
Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	193,532,100	0.0004	77,413	1,690,203	0.0004	676	
GS < 50	kWh	48,518,497	0.0004	19,407	10,203,902	0.0004	4,082	
GS > 50 (excluding WMP)	kWh	841,461	0.0004	337	87,666,253	0.0004	35,067	
WMP	kWh	-	0.0004	-	2,743,349	-	-	
Street Light	kWh	-	0.0004	-	1,540,002	0.0004	616	
Sentinel Light	kWh	340,183	0.0004	136	58,119	0.0004	23	
USL	kWh	757,291	0.0004	303	80,360	0.0004	32	
SUB-TOTAL				97,596			40,496	138,091
RRRP								
Class per Load Forecast							$	Total
Residential	kWh	193,532,100	0.0014	270,945	1,690,203	0.0014	2,366	
GS < 50	kWh	48,518,497	0.0014	67,926	10,203,902	0.0014	14,285	
GS > 50 (excluding WMP)	kWh	841,461	0.0014	1,178	136,160,036	0.0014	190,624	
WMP	kWh	-	0.0014	-	2,743,349	-	-	
Street Light	kWh	-	0.0014	-	1,540,002	0.0014	2,156	
Sentinel Light	kWh	340,183	0.0014	476	58,119	0.0014	81	
USL	kWh	757,291	0.0014	1,060	80,360	0.0014	113	
SUB-TOTAL				341,585			209,626	551,211
Low Voltage - No TLF adjustment								
Class per Load Forecast							$	Total
Residential				-			-	
GS < 50				-			-	
GS > 50 (excluding WMP)				-			-	
WMP				-			-	
Street Light				-			-	
Sentinel Light				-			-	
USL				-			-	
SUB-TOTAL				-			-	-
Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential		23,882	0.42	120,365	237	0.42	1,192	
GS < 50		1,740	0.42	8,772	129	0.42	648	
SUB-TOTAL				129,137			1,840	130,977
SUB- TOTAL				33,916,564			17,645,537	51,562,100
OER CREDIT	19.3%			(6,545,897)			0	(6,545,897)
TOTAL				**27,370,667**			**17,645,537**	**45,016,203**

2.6 Distribution System Plan

WHESC has prepared its Distribution System Plan ("DSP") in accordance with the OEB's Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications. The DSP is being filed as a stand-alone and self-sufficient document as Appendix 2-E to this Exhibit. WHESC has organized the information contained in the DSP using the headings indicated in Chapter 5 of the Filing Requirements.

2.7 Policy Options for the Funding of Capital

On September 18, 2014, the OEB issued the *Report of the Board on New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (the ACM Report).* In this report, the OEB established the following mechanism to assist distributors in aligning capital spending and prioritization with better rate predictability and smoothing:

The review and approval of business cases for incremental capital requests that are subject to the criteria of materiality, need and prudence are advanced to coincide with the distributor's cost of service application. To distinguish this from the Incremental Capital Module ("ICM"), this new mechanism will be named the Advanced Capital Module ("ACM").

Advancing the reviews of eligible discrete capital projects, included as part of the distributor's Distribution System Plan ("DSP") and scheduled to go into service during the IR term, is expected to facilitate enhanced pacing and smoothing of rate impacts, as the distributor, the board and other stakeholders will be examining the capital projects over the five-year horizon of the DSP.

WHESC has a discrete capital project within the five-year horizon that it believes would be potentially eligible for this policy option. At this time, it is too early in the investment planning process to make an adequate business case for an investment and meet all the criteria of an ACM. As a result, WHESC is not requesting approval of an ACM mechanism in this rate application.

The subject project is related to WHESC connecting to the upgraded Crowland Transformer Station ("TS") scheduled for completion as part of the Niagara Regional Infrastructure Plan ("RIP") that followed the most recent Integrated Regional Resource Plan ("IRRP"). WHESC anticipates a requirement to fund the capacity incremental of the new TS as well as capital investment requirements related to new feeder egress, facilitating connection of the supply to existing 27.6 kV loads.

2.8 Addition of Previously Approved ACM and ICM Project Assets to Rate Base

WHESC confirms that it has not applied for nor received any ACM or ICM from a previous IRM application. As a result, no ACM or ICM related assets have been added to rate base and WHESC has not completed the Board's Capital Module applicable to ACM and ICM.

2.9 Capitalization

2.9.1 Capitalization Policy

WHESC's current capitalization policy is based on International Financial Reporting Standards ("IFRS") and guidelines set out by the Board, where applicable. WHESC converted to Modified International Financial

Reporting Standards ("MIFRS") for financial reporting purposes on January 1, 2015, and as such, the capitalization policy in effect for the 2024 Bridge Year and 2025 Test Year is compliant with MIFRS. WHESC confirms that no changes have been made to its capitalization policy since its 2017 Cost of Service application (EB-2016-0110).

Capital Assets include property, plant and equipment that are held for use in the production or supply of goods and services and provide a benefit lasting beyond one year. Capital Assets includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour, and other costs directly attributable to bringing the asset to working condition for its intended use.

Intangible assets are also considered capital assets under this criterion. They are defined as assets that lack physical substance and include goodwill, patents, copyrights and computer software.

Capital expenditures also include the improvement or "betterment" of existing assets. A betterment is defined as a cost which enhances the service potential of a capital asset and/or increases its value. A betterment includes expenditures which increase the capacity of the asset, lower associated operating costs, improve the quality of output, or extend the asset's useful life. A betterment does not include general maintenance-related actions that seek to sustain an asset's current value.

Alternatively, 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.

When parts or components of an item of property, plant and equipment have different useful lives, they are accounted for as individual items (major components) of the property, plant and equipment. Components are those which are significant in relation to the total cost of the item and have different depreciation methods or useful lives. Components with similar useful lives and depreciation methods are grouped for the purpose of determining the depreciation charge. Parts of the item that are not individually significant (remainder of the items) are combined and categorized as a single component.

2.9.2 Overhead Costs

IFRS prescribes which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to bringing an asset to the location and to a condition necessary for it to operate in a manner intended by management can be capitalized. Indirect costs, such as general and administrative costs that are not directly attributable to an asset cannot be capitalized under IFRS. WHESC has not changed its capitalization policy since its 2017 Board approved Cost of Service.

WHESC calculates an overhead percentage for payroll benefits, considered labour “burdens.” The burden cost includes vacation, statutory holidays, sick time, CPP, EI, OMERs contributions, health care and other employee benefits. Post Retirement Benefit expenses are not included in this calculation. The resulting overhead percentage is attached to employee hourly rates through the payroll system. Through the timesheet process, employees track their hours by specific work order. This process ensures that only direct labour costs including burden are charged to capital projects.

Table 2-25 below is consistent with Board Appendix 2-D and has been completed to show WHESC’s OM&A costs prior to, and after, the allocation of costs to capital projects.

Table 2-25: Summary of Overhead Expense

Description	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
OM&A Before Capitalization									
Operations & Maintenance	3,924,037	3,997,752	4,224,405	4,210,878	4,448,863	4,469,748	4,572,978	4,469,748	4,572,978
Billing and Collecting	1,428,794	1,399,519	1,327,067	1,500,139	1,393,265	1,491,435	1,474,496	1,491,435	1,474,496
Community Relations	149,386	169,206	153,684	63,668	41,182	53,290	59,435	48,883	53,068
Administrative & General	1,809,550	1,829,645	1,854,281	1,735,848	1,688,313	1,771,569	1,878,832	1,775,977	1,885,199
Total OM&A Before Capitalization	7,311,767	7,396,123	7,559,437	7,510,533	7,571,623	7,786,043	7,985,742	7,786,043	7,985,742
Capitalized Employee Labour	545,454	600,040	623,568	690,699	787,171	702,547	747,471	702,547	747,471
% of Capitalized OM&A	7.46%	8.11%	8.25%	9.20%	10.40%	9.02%	9.36%	9.02%	9.36%

2.9.3 Burden Rates

WHESC only has one overhead that is charged to capital, which is labour burden. This cost is directly allocated to capital through a burden rate set up in the payroll system. The current labour burden rate is 50% of direct labour costs. This rate is only adjusted when a significant change in labour burden to total wages occurs. No change has been made to the current burden rate since the 2017 Cost of Service application.

2.10 Costs of Eligible Investments for the Connection of Qualifying Generation Facilities

WHESC received approval in its 2017 COS application (EB-2016-0110) to obtain payment from the IESO for Ratepayer Protection under O.Reg.330/09 in the amount of $5,172 annually by payment of $431 monthly for Renewable Generation Connection-Provincial Amount. The approval related to an investment in 2014 at an actual cost of $88,852. WHESC confirms that no additional costs related to this investment have been incurred.

WHESC has received total payment from the IESO related to this investment between May 2017 and December 2023 in the amount of $47,188. Per the Decision and Order for 2024 Renewable Generation Connection Rate Protection Compensation Amount Effective June 1, 2024 (EB-2024-0137), WHESC will continue to receive $431 per month until such time as the OEB orders otherwise. Total actual payment received from the IESO from May 2017 to December 2023, as well as the projected amount for the 2024 Test Year, can be seen in Table 2-26 below.

Table 2-26: Rate Protection Payments Received from the IESO

Year	Payment Received
2017	11,920
2018	9,408
2019	5,172
2020	5,172
2021	5,172
2022	5,172
2023	5,172
2024 Bridge Year	5,172
Total	**52,360**

WHESC has completed the Board's Appendix 2-FA and 2-FC to update depreciation and calculate a new up-to-date rate protection amount for the 2025 Test Year through to 2030. Appendix 2-FA and 2-FC have been filed in live Excel format as part of this application.

WHESC is proposing to update it's annual rate protection amount from the current amount of $5,172 to a revised amount of $5,107 in 2025. A summary of the 2017 Board Approved amount, and the updated 2025 to 2030 amounts, are summarized in Table 2-27 below.

Table 2-27: Updated Rate Protection Amount

	2017 Board Approved			2025 Test Year			2026	2027	2028	2029	2030
	Total	Direct Benefit	Provincial	Total	Direct Benefit	Provincial	Provincial	Provincial	Provincial	Provincial	Provincial
		17%	83%		17%	83%	83%	83%	83%	83%	83%
Average NBV	**83,521**	**14,199**	**69,322**	**69,305**	**11,782**	**57,523**	**56,048**	**54,573**	**53,098**	**51,623**	**50,148**
Deemed ST Debt	4%	568	2,773	4%	471	2,301	2,242	2,183	2,124	2,065	2,006
Deemed LT Debt	56%	7,951	38,821	56%	6,598	32,213	31,387	30,561	29,735	28,909	28,083
Deemed Equity	40%	5,679	27,729	40%	4,713	23,009	22,419	21,829	21,239	20,649	20,059
ST Interest	2.08%	12	58	1.76%	8	40	39	38	37	36	35
LT Interest	3.78%	301	1,467	3.72%	245	1,198	1,168	1,137	1,106	1,075	1,045
ROE	8.93%	507	2,476	8.78%	414	2,020	1,968	1,917	1,865	1,813	1,761
Cost of Capital Total		**820**	**4,001**		**668**	**3,259**	**3,175**	**3,092**	**3,008**	**2,925**	**2,841**
OM&A											
Amortization (50 years)	1,777	302	1,475	1,777	302	1,475	1,475	1,475	1,475	1,475	1,475
Grossed-up PILs		- 62	- 304		76	373	425	472	513	550	582
Revenue Requirement		**1,059**	**5,172**		**1,046**	**5,107**	**5,076**	**5,039**	**4,997**	**4,950**	**4,898**
Income Tax											
Net income (ROE)		507	2,476		414	2,020	1,968	1,917	1,865	1,813	1,761
Depreciation		302	1,475		302	1,475	1,475	1,475	1,475	1,475	1,475
CCA (8%)	- 5,776	- 982	- 4,794	- 2,964	- 504	- 2,460	- 2,263	- 2,082	- 1,916	- 1,763	- 1,622
Taxable Income		- 173	- 843		212	1,035	1,180	1,309	1,424	1,525	1,615
Income Taxes Payable (26.5%)		- 46	- 223		56	274	313	347	377	404	428
Grossed up PILs		**- 62**	**- 304**		**76**	**373**	**425**	**472**	**513**	**550**	**582**

Appendix 2-A: OEB Appendix 2-AA Capital Projects Table

Appendix 2-A – (OEB Appendix 2-AA: Capital Projects)

Appendix 2-AA
Capital Projects Table

Projects	2017	2018	2019	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year	2026	2027	2028	2029
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access													
Municipal Relocations/Expansions	26,405	0	0	6,218	185,672	330,025	202,628	798,600	0	0	0	0	0
Residential Services	-43,226	39,752	25,304	29,486	-8,657	39,744	209,946	45,000	46,350	47,741	49,173	50,648	52,167
General Services	19,350	11,016	87,602	150,655	59,367	109,264	226,842	232,780	239,763	246,956	254,365	261,996	269,856
Subdivisions	0	189,771	297,973	1,312,854	681,590	471,937	1,188,012	1,103,000	1,136,000	1,170,000	1,205,000	1,242,000	1,279,000
Meters	73,499	183,342	63,328	48,816	125,509	111,558	315,961	150,000	154,500	159,135	163,909	168,826	173,891
System Access Gross Expenditures	**76,028**	**423,881**	**474,207**	**1,548,029**	**1,043,481**	**1,062,528**	**2,143,389**	**2,329,380**	**1,576,613**	**1,623,832**	**1,672,447**	**1,723,470**	**1,774,914**
System Access Capital Contributions	38,318	170,819	341,881	1,121,885	711,923	637,193	1,219,363	1,720,463	974,149	1,003,563	1,034,110	1,064,794	1,096,617
Sub-Total	**37,710**	**253,062**	**132,326**	**426,144**	**331,558**	**425,335**	**924,026**	**608,917**	**602,464**	**620,269**	**638,337**	**658,676**	**678,297**
System Renewal													
Substation Renewal	324,114	199,795	307,644	216,481	39,933	758,757	0	0	360,000	0	300,000	0	0
Overhead Line Renewal	697,734	185,039	390,788	932,087	1,261,288	1,016,650	1,311,615	1,700,000	1,050,000	1,625,000	945,000	1,392,000	600,000
Underground Line Renewal	436,622	348,013	593,399	637,020	291,811	33,801	410,500	350,000	807,500	805,225	843,182	1,121,377	1,964,819
Pole Replacements	174,279	525,673	406,369	262,552	310,752	239,673	350,892	150,000	302,387	311,459	320,803	330,427	340,340
Transformer Replacements/Spares	134,948	123,096	146,891	157,039	175,043	407,409	97,715	80,000	161,273	166,111	171,095	176,228	181,514
Reactive Underground Replacements	15,441	6,860	43,219	3,962	17,893	68,393	34,731	50,000	51,500	53,045	54,636	56,275	57,964
Reactive Overhead Replacements	5,285	29,220	47,646	63,039	149,045	89,779	122,834	75,000	151,194	155,729	160,401	165,213	170,170
System Renewal Gross Expenditures	1,788,423	1,417,696	1,935,956	2,272,180	2,245,765	2,614,461	2,328,287	2,405,000	2,883,854	3,116,570	2,795,117	3,241,520	3,314,806
System Renewal Capital Contributions													
Sub-Total	**1,788,423**	**1,417,696**	**1,935,956**	**2,272,180**	**2,245,765**	**2,614,461**	**2,328,287**	**2,405,000**	**2,883,854**	**3,116,570**	**2,795,117**	**3,241,520**	**3,314,806**
System Service													
Grid Modernization	28,500	112,550	103,042	78,835	267,139	312,926	141,237	160,000	242,050	249,312	256,791	264,495	272,429
Grid Reinforcement	0	0	0	0	0	0	0	0	0	250,000	225,000	100,000	0
System Service Gross Expenditures	28,500	112,550	103,042	78,835	267,139	312,926	141,237	160,000	242,050	499,312	481,791	364,495	272,429
System Service Capital Contributions													
Sub-Total	**28,500**	**112,550**	**103,042**	**78,835**	**267,139**	**312,926**	**141,237**	**160,000**	**242,050**	**499,312**	**481,791**	**364,495**	**272,429**
General Plant													
Office Equipment	0	0	7,568	0	16,610	48,128	0	20,000	50,000	18,000	5,200	5,356	5,517
Information Systems	140,360	215,087	367,280	271,643	68,550	23,930	44,675	27,640	140,000	41,115	46,014	20,496	21,110
Fleet	73,276	220,017	459,036	31,355	361,328	49,859	196,853	65,000	528,971	214,101	465,878	153,158	75,353
Bulding Improvements	132,478	107,804	345,644	6,683	5,193	0	36,404	389,630	125,000	194,000	32,500	35,000	112,500
Tools	11,746	20,374	21,063	4,400	3,762	0	0	32,800	110,609	30,927	31,855	11,593	56,941
General Plant Gross Expenditures	357,860	563,282	1,200,591	314,081	455,443	121,917	277,932	535,070	954,580	498,143	581,447	225,602	271,420
General Plant Capital Contributions													
Sub-Total	**357,860**	**563,282**	**1,200,591**	**314,081**	**455,443**	**121,917**	**277,932**	**535,070**	**954,580**	**498,143**	**581,447**	**225,602**	**271,420**
Miscellaneous													
Total	**2,212,493**	**2,346,590**	**3,371,915**	**3,091,240**	**3,299,905**	**3,474,639**	**3,671,482**	**3,708,987**	**4,682,948**	**4,734,293**	**4,496,692**	**4,490,293**	**4,536,953**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets ***(input as negative)***													
Total	**2,212,493**	**2,346,590**	**3,371,915**	**3,091,240**	**3,299,905**	**3,474,639**	**3,671,482**	**3,708,987**	**4,682,948**	**4,734,293**	**4,496,692**	**4,490,293**	**4,536,953**
MIST Meters		-82,710											
		2,263,880											

Appendix 2-B: OEB Appendix 2-AB
Capital Expenditures

Appendix 2-B – (OEB Appendix 2-AB - Capital Expenditures)

CATEGORY	Historical Period (previous plan[1] & actual)											
	2017			2018			2019			2020		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	140	76	-45.7%	250	424	69.6%	250	474	89.7%	190	1,548	714.7%
System Renewal	1,735	1,788	3.1%	1,495	1,418	-5.2%	1,775	1,936	9.1%	1,920	2,272	18.3%
System Service	80	29	-64.4%	260	113	-56.7%	35	103	194.3%	35	79	125.1%
General Plant	155	358	130.9%	305	563	84.7%	400	1,201	200.2%	295	314	6.5%
TOTAL EXPENDITURE	2,110	2,251	6.7%	2,310	2,517	9.0%	2,460	3,714	51.0%	2,440	4,213	72.7%
Capital Contributions	-	- 38	--	-	- 171	--	-	- 342	--	-	- 1,122	--
NET CAPITAL EXPENDITURES	2,110	2,212	4.9%	2,310	2,347	1.6%	2,460	3,372	37.1%	2,440	3,091	26.7%
System O&M	$ 3,314	$ 3,379	1.9%	$ 3,380	$ 3,398	0.5%	$ 3,671	$ 3,601	-1.9%	$ 3,759	$ 3,520	-6.4%

CATEGORY	Historical Period (previous plan[1] & actual)												Forecast Period (planned)				
	2021			2022			2023			2024			2025	2026	2027	2028	2029
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	150	1,043	595.7%	715	1,063	48.6%	490	2,143	337.4%	2,329		-100.0%	1,577	1,624	1,672	1,724	1,775
System Renewal	1,770	2,246	26.9%	2,185	2,614	19.7%	2,200	2,328	5.8%	2,405		-100.0%	2,884	3,117	2,795	3,242	3,315
System Service	35	267	663.1%	210	313	49.0%	220	141	-35.9%	160		-100.0%	242	499	482	364	272
General Plant	525	455	-13.3%	205	122	-40.5%	460	278	-39.6%	535		-100.0%	955	498	581	226	271
TOTAL EXPENDITURE	2,480	4,012	61.8%	3,315	4,112	24.0%	3,370	4,891	45.1%	5,429	-	-100.0%	5,658	5,738	5,530	5,556	5,633
Capital Contributions	-	- 712	--	- 50	- 637	1174.3%	- 50	- 1,219	2338.6%	- 1,720		-100.0%	- 974	- 1,004	- 1,034	- 1,065	- 1,097
NET CAPITAL EXPENDITURES	2,480	3,300	33.1%	3,265	3,475	6.4%	3,320	3,671	10.6%	3,709		-100.0%	4,683	4,734	4,496	4,491	4,536
System O&M	$ 3,960	$ 3,662	-7.5%	$ 3,879	$ 3,767	-2.9%	$ 4,054	$ 3,826	-5.6%	$ 4,175		-100.0%	$ 4,705	$ 4,889	$ 5,063	$ 5,182	$ 5,336

Appendix 2-C: OEB Appendix 2-BA Fixed Asset Continuity Schedules

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
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)	$ 966,997	$ 126,550		$ 1,093,547	-$ 677,845	-$ 104,090		-$ 781,935	$ 311,612
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 62,192	-$ 640		-$ 62,832	$ 7,464
N/A	1805	Land	$ 158,686			$ 158,686	-$ 1,236			-$ 1,236	$ 157,450
47	1808	Buildings	$ 96,568			$ 96,568	-$ 63,698	-$ 1,236		-$ 64,934	$ 31,634
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 97,274	-$ 14,857		-$ 112,131	$ 355,228
47	1820	Distribution Station Equipment <50 kV	$ 4,491,261	$ 3,000	-$ 269,283	$ 4,224,978	-$ 2,681,728	-$ 89,556	$ 257,079	-$ 2,514,206	$ 1,710,772
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 9,991,568	$ 600,349		$ 10,591,918	-$ 1,775,470	-$ 194,473		-$ 1,969,943	$ 8,621,974
47	1835	Overhead Conductors & Devices	$ 13,762,667	$ 180,579		$ 13,943,246	-$ 8,824,327	-$ 143,136		-$ 8,967,463	$ 4,975,783
47	1840	Underground Conduit	$ 1,542,830	$ 462,310		$ 2,005,139	-$ 220,036	-$ 34,211		-$ 254,247	$ 1,750,892
47	1845	Underground Conductors & Devices	$ 11,436,604	$ 243,987		$ 11,680,592	-$ 7,793,353	-$ 188,584		-$ 7,981,937	$ 3,698,655
47	1850	Line Transformers	$ 7,198,277	$ 357,028	-$ 18,989	$ 7,536,316	-$ 3,622,017	-$ 129,138	$ 14,779	-$ 3,736,376	$ 3,799,940
47	1855	Services (Overhead & Underground)	$ 855,562	$ 10,720		$ 866,282	-$ 196,154	-$ 20,339		-$ 216,492	$ 649,789
47	1860	Meters	$ 3,071,875	$ 73,499	-$ 53,113	$ 3,092,261	-$ 1,357,767	-$ 204,560	$ 33,862	-$ 1,528,466	$ 1,563,795
47	1860	Meters (Smart Meters)				$ -				$ -	$ -
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures	$ 2,635,551	$ 93,230		$ 2,728,781	-$ 1,309,433	-$ 67,598		-$ 1,377,031	$ 1,351,750
13	1910	Leasehold Improvements				$ -				$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,445			$ 90,445	-$ 78,382	-$ 3,896		-$ 82,278	$ 8,167
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware				$ -				$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 234,822	$ 13,810		$ 248,633	-$ 123,003	-$ 53,089		-$ 176,091	$ 72,541
10	1930	Transportation Equipment	$ 2,178,574	$ 73,276	-$ 254,812	$ 1,997,038	-$ 1,030,124	-$ 109,892	$ 254,812	-$ 885,204	$ 1,111,834
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 100,814	$ 50,994		$ 151,808	-$ 76,557	-$ 8,128		-$ 84,685	$ 67,123
8	1945	Measurement & Testing Equipment	$ 20,451			$ 20,451	-$ 16,819	-$ 771		-$ 17,590	$ 2,861
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 298,231			$ 298,231	-$ 188,991	-$ 28,678		-$ 217,669	$ 80,563
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 126,063	-$ 11,128		-$ 137,191	$ 178,045
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 779,964	$ 28,500		$ 808,464	-$ 606,349	-$ 43,771		-$ 650,120	$ 158,343
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 718,435	-$ 36,018		-$ 754,453	$ 30,349	$ 22,644		$ 52,993	-$ 701,460
47	2440	Deferred Revenue[5]				$ -				$ -	$ -
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 60,076,227**	**$ 2,281,816**	**-$ 596,198**	**$ 61,761,845**	**-$ 30,928,494**	**-$ 1,429,125**	**$ 560,532**	**-$ 31,797,087**	**$ 29,964,758**
		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	**$ 60,076,227**	**$ 2,281,816**	**-$ 596,198**	**$ 61,761,845**	**-$ 30,928,494**	**-$ 1,429,125**	**$ 560,532**	**-$ 31,797,087**	**$ 29,964,758**
		Construction Work In Progress	$ 69,322	-$ 69,322		$ -				$ -	$ -
		Total PP&E	**$ 60,145,549**	**$ 2,212,494**	**-$ 596,198**	**$ 61,761,845**	**-$ 30,928,494**	**-$ 1,429,125**	**$ 560,532**	**-$ 31,797,087**	**$ 29,964,758**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,429,125**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$1,429,125**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
Year 2018

			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)	$ 1,093,547			$ 1,093,547	-$ 781,935	-$ 145,613		-$ 927,548	$ 165,999
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 62,832	-$ 640		-$ 63,472	$ 6,824
N/A	1805	Land	$ 158,686			$ 158,686	-$ 1,236			-$ 1,236	$ 157,450
47	1808	Buildings	$ 96,568			$ 96,568	-$ 64,934	-$ 1,236		-$ 66,169	$ 30,399
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 112,131	-$ 14,857		-$ 126,987	$ 340,371
47	1820	Distribution Station Equipment <50 kV	$ 4,224,978	$ 228,181		$ 4,453,159	-$ 2,514,206	-$ 87,030		-$ 2,601,236	$ 1,851,923
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 10,591,918	$ 707,453		$ 11,299,371	-$ 1,969,943	-$ 207,697		-$ 2,177,640	$ 9,121,731
47	1835	Overhead Conductors & Devices	$ 13,943,246	$ 81,248		$ 14,024,494	-$ 8,967,463	-$ 145,808		-$ 9,113,271	$ 4,911,223
47	1840	Underground Conduit	$ 2,005,139	$ 73,039		$ 2,078,178	-$ 254,247	-$ 39,564		-$ 293,811	$ 1,784,367
47	1845	Underground Conductors & Devices	$ 11,680,592	$ 242,240		$ 11,922,832	-$ 7,981,937	-$ 196,687		-$ 8,178,624	$ 3,744,208
47	1850	Line Transformers	$ 7,536,316	$ 303,002	-$ 42,184	$ 7,797,133	-$ 3,736,376	-$ 137,726	$ 28,377	-$ 3,845,725	$ 3,951,408
47	1855	Services (Overhead & Underground)	$ 866,282	$ 47,970		$ 914,252	-$ 216,492	-$ 21,072		-$ 237,565	$ 676,687
47	1860	Meters	$ 3,092,261	$ 100,332	-$ 9,672	$ 3,182,921	-$ 1,528,466	-$ 209,611	$ 5,326	-$ 1,732,750	$ 1,450,171
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 2,728,781	$ 107,804		$ 2,836,585	-$ 1,377,031	-$ 70,622		-$ 1,447,653	$ 1,388,932
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,445			$ 90,445	-$ 82,278	-$ 2,243		-$ 84,522	$ 5,924
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 248,633			$ 248,633	-$ 176,091	-$ 43,468		-$ 219,559	$ 29,074
10	1930	Transportation Equipment	$ 1,997,038	$ 220,016	-$ 209,354	$ 2,007,700	-$ 885,204	-$ 125,550	$ 206,990	-$ 803,765	$ 1,203,936
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 151,808		-$ 2,941	$ 148,867	-$ 84,685	-$ 9,235	$ 2,765	-$ 91,155	$ 57,712
8	1945	Measurement & Testing Equipment	$ 20,451	$ 20,374		$ 40,825	-$ 17,590	-$ 1,708		-$ 19,298	$ 21,527
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 298,231			$ 298,231	-$ 217,669	-$ 16,613		-$ 234,282	$ 63,949
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 137,191	-$ 11,128		-$ 148,319	$ 166,917
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 808,464	$ 54,389		$ 862,853	-$ 650,120	-$ 29,203		-$ 679,324	$ 183,529
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 754,453	-$ 170,518		-$ 924,971	$ 52,993	$ 25,552		$ 78,545	-$ 846,425
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 61,761,845**	**$ 2,015,531**	**-$ 264,151**	**$ 63,513,224**	**-$ 31,797,087**	**-$ 1,491,760**	**$ 243,458**	**-$ 33,045,389**	**$ 30,467,836**
		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	**$ 61,761,845**	**$ 2,015,531**	**-$ 264,151**	**$ 63,513,224**	**-$ 31,797,087**	**-$ 1,491,760**	**$ 243,458**	**-$ 33,045,389**	**$ 30,467,836**
		Construction Work In Progress	$ -	$ 248,350		$ 248,350				$ -	$ 248,350
		Total PP&E	**$ 61,761,845**	**$ 2,263,881**	**-$ 264,151**	**$ 63,761,574**	**-$ 31,797,087**	**-$ 1,491,760**	**$ 243,458**	**-$ 33,045,389**	**$ 30,716,186**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,491,760**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 1,491,760**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
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)	$ 1,093,547	$ 382,313		$ 1,475,860	-$ 927,548	-$ 140,956		-$ 1,068,504	$ 407,356
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 63,472	-$ 640		-$ 64,112	$ 6,184
N/A	1805	Land	$ 158,686		-$ 3,000	$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 96,568			$ 96,568	-$ 66,169	-$ 1,236		-$ 67,405	$ 29,163
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 126,987	-$ 14,857		-$ 141,844	$ 325,515
47	1820	Distribution Station Equipment <50 kV	$ 4,453,159	$ 214,481	-$ 89,718	$ 4,577,922	-$ 2,601,236	-$ 94,568	$ 89,718	-$ 2,606,086	$ 1,971,836
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 11,299,371	$ 716,853		$ 12,016,224	-$ 2,177,640	-$ 221,940		-$ 2,399,580	$ 9,616,644
47	1835	Overhead Conductors & Devices	$ 14,024,494	$ 124,433		$ 14,148,927	-$ 9,113,271	-$ 147,865		-$ 9,261,136	$ 4,887,792
47	1840	Underground Conduit	$ 2,078,178	$ 67,831		$ 2,146,009	-$ 293,811	-$ 40,973		-$ 334,784	$ 1,811,225
47	1845	Underground Conductors & Devices	$ 11,922,832	$ 377,332		$ 12,300,164	-$ 8,178,624	-$ 207,014		-$ 8,385,637	$ 3,914,527
47	1850	Line Transformers	$ 7,797,133	$ 753,899	-$ 54,059	$ 8,496,973	-$ 3,845,725	-$ 150,938	$ 32,778	-$ 3,963,885	$ 4,533,088
47	1855	Services (Overhead & Underground)	$ 914,252	$ 14,227		$ 928,479	-$ 237,565	-$ 21,850		-$ 259,415	$ 669,065
47	1860	Meters	$ 3,182,921	$ 63,328	-$ 29,546	$ 3,216,703	-$ 1,732,750	-$ 214,906	$ 26,283	-$ 1,921,373	$ 1,295,330
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 2,836,585	$ 345,645		$ 3,182,230	-$ 1,447,653	-$ 84,429		-$ 1,532,082	$ 1,650,148
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 90,445		-$ 72,282	$ 18,163	-$ 84,522	-$ 1,816	$ 72,282	-$ 14,056	$ 4,107
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 248,633	$ 148,293		$ 396,926	-$ 219,559	-$ 35,988		-$ 255,547	$ 141,379
10	1930	Transportation Equipment	$ 2,007,700	$ 459,036	-$ 153,526	$ 2,313,210	-$ 803,765	-$ 147,329	$ 153,526	-$ 797,568	$ 1,515,642
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 148,867	$ 21,063		$ 169,930	-$ 91,155	-$ 8,875		-$ 100,030	$ 69,900
8	1945	Measurement & Testing Equipment	$ 40,825			$ 40,825	-$ 19,298	-$ 2,726		-$ 22,024	$ 18,800
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 298,231	$ 7,568		$ 305,800	-$ 234,282	-$ 17,370		-$ 251,653	$ 54,147
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 148,319	-$ 11,128		-$ 159,446	$ 155,789
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 862,853	$ 75,651		$ 938,504	-$ 679,324	-$ 31,055		-$ 710,379	$ 228,126
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 924,971	-$ 357,264		-$ 1,282,235	$ 78,545	$ 33,417		$ 111,962	-$ 1,170,273
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 63,513,224**	**$ 3,414,689**	**-$ 402,131**	**$ 66,525,782**	**-$ 33,045,389**	**-$ 1,565,041**	**$ 374,587**	**-$ 34,235,843**	**$ 32,289,940**
		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	**$ 63,513,224**	**$ 3,414,689**	**-$ 402,131**	**$ 66,525,782**	**-$ 33,045,389**	**-$ 1,565,041**	**$ 374,587**	**-$ 34,235,843**	**$ 32,289,940**
		Construction Work In Progress	$ 248,350	-$ 42,773	$ -	$ 205,577				$ -	$ 205,577
		Total PP&E	**$ 63,761,574**	**$ 3,371,916**	**-$ 402,131**	**$ 66,731,359**	**-$ 33,045,389**	**-$ 1,565,041**	**$ 374,587**	**-$ 34,235,843**	**$ 32,495,517**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,565,041**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 1,565,041**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
Year 2020

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)	$ 1,475,860	$ 287,678	-$ 897,399	$ 866,138	-$ 1,068,504	-$ 130,541	$ 897,399	-$ 301,645	$ 564,493
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 64,112	-$ 640		-$ 64,752	$ 5,544
N/A	1805	Land	$ 155,686			$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 96,568			$ 96,568	-$ 67,405	-$ 1,238		-$ 68,643	$ 27,925
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 141,844	-$ 14,858		-$ 156,702	$ 310,657
47	1820	Distribution Station Equipment <50 kV	$ 4,577,922	$ 309,643	-$ 71,022	$ 4,816,542	-$ 2,606,086	-$ 99,872	$ 71,022	-$ 2,634,936	$ 2,181,606
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,016,224	$ 615,168		$ 12,631,392	-$ 2,399,580	-$ 235,258		-$ 2,634,838	$ 9,996,554
47	1835	Overhead Conductors & Devices	$ 14,148,927	$ 457,830		$ 14,606,758	-$ 9,261,136	-$ 153,686		-$ 9,414,821	$ 5,191,936
47	1840	Underground Conduit	$ 2,146,009	$ 338,322		$ 2,484,331	-$ 334,784	-$ 45,034		-$ 379,818	$ 2,104,513
47	1845	Underground Conductors & Devices	$ 12,300,164	$ 1,222,095		$ 13,522,260	-$ 8,385,637	-$ 225,100		-$ 8,610,737	$ 4,911,523
47	1850	Line Transformers	$ 8,496,973	$ 903,514	-$ 32,135	$ 9,368,352	-$ 3,963,885	-$ 169,746	$ 13,507	-$ 4,120,124	$ 5,248,228
47	1855	Services (Overhead & Underground)	$ 928,479	$ 26,655		$ 955,134	-$ 259,415	-$ 22,361		-$ 281,776	$ 673,358
47	1860	Meters	$ 3,216,703	$ 48,816	-$ 9,917	$ 3,255,602	-$ 1,921,373	-$ 215,594	$ 6,676	-$ 2,130,291	$ 1,125,311
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 3,182,230	$ 9,052		$ 3,191,281	-$ 1,532,082	-$ 96,219		-$ 1,628,300	$ 1,562,981
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 18,163			$ 18,163	-$ 14,056	-$ 1,816		-$ 15,872	$ 2,291
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 396,926	$ 35,725	-$ 146,769	$ 285,882	-$ 255,547	-$ 39,038	$ 146,769	-$ 147,816	$ 138,066
10	1930	Transportation Equipment	$ 2,313,210	$ 31,355		$ 2,344,565	-$ 797,568	-$ 163,127		-$ 960,694	$ 1,383,870
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 169,930	$ 4,400		$ 174,330	-$ 100,030	-$ 9,457		-$ 109,488	$ 64,842
8	1945	Measurement & Testing Equipment	$ 40,825			$ 40,825	-$ 22,024	-$ 2,726		-$ 24,751	$ 16,074
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 305,800	-$ 2,365		$ 303,435	-$ 251,653	-$ 17,418		-$ 269,070	$ 34,365
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 159,446	-$ 11,128		-$ 170,574	$ 144,661
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 938,504	$ 139,489		$ 1,077,993	-$ 710,379	-$ 29,253		-$ 739,632	$ 338,361
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 1,282,235	-$ 1,136,776		-$ 2,419,011	$ 111,962	$ 56,123		$ 168,085	-$ 2,250,926
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 66,525,782**	**$ 3,290,599**	**-$ 1,157,242**	**$ 68,659,139**	**-$ 34,235,843**	**-$ 1,627,988**	**$ 1,135,373**	**-$ 34,728,457**	**$ 33,930,681**
		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	**$ 66,525,782**	**$ 3,290,599**	**-$ 1,157,242**	**$ 68,659,139**	**-$ 34,235,843**	**-$ 1,627,988**	**$ 1,135,373**	**-$ 34,728,457**	**$ 33,930,681**
		Construction Work In Progress	$ 205,577	-$ 199,359	$ -	$ 6,218				$ -	$ 6,218
		Total PP&E	**$ 66,731,359**	**$ 3,091,240**	**-$ 1,157,242**	**$ 68,665,357**	**-$ 34,235,843**	**-$ 1,627,988**	**$ 1,135,373**	**-$ 34,728,457**	**$ 33,936,900**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,627,988**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 1,627,988**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard	MIFRS
Year	2021

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)	$ 866,138	$ 11,781		$ 877,919	-$ 301,645	-$ 160,781		-$ 462,426	$ 415,493
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 64,752	-$ 640		-$ 65,392	$ 4,904
N/A	1805	Land	$ 155,686			$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 96,568	$ 5,193		$ 101,761	-$ 68,643	-$ 1,495		-$ 70,138	$ 31,622
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 156,702	-$ 14,857		-$ 171,559	$ 295,800
47	1820	Distribution Station Equipment <50 kV	$ 4,816,542	$ 33,456	-$ 54,009	$ 4,795,989	-$ 2,634,936	-$ 105,275	$ 13,189	-$ 2,727,023	$ 2,068,966
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 12,631,392	$ 1,037,962		$ 13,669,354	-$ 2,634,838	-$ 251,791		-$ 2,886,629	$ 10,782,725
47	1835	Overhead Conductors & Devices	$ 14,606,758	$ 602,273		$ 15,209,031	-$ 9,414,821	-$ 164,288		-$ 9,579,110	$ 5,629,921
47	1840	Underground Conduit	$ 2,484,331	$ 148,829		$ 2,633,160	-$ 379,818	-$ 49,906		-$ 429,724	$ 2,203,436
47	1845	Underground Conductors & Devices	$ 13,522,260	$ 744,429		$ 14,266,689	-$ 8,610,737	-$ 256,363		-$ 8,867,100	$ 5,399,588
47	1850	Line Transformers	$ 9,368,352	$ 610,941	-$ 11,634	$ 9,967,659	-$ 4,120,124	-$ 187,872	$ 6,927	-$ 4,301,069	$ 5,666,589
47	1855	Services (Overhead & Underground)	$ 955,134	-$ 8,657		$ 946,477	-$ 281,776	-$ 22,586		-$ 304,362	$ 642,115
47	1860	Meters	$ 3,255,602	$ 125,509	-$ 14,732	$ 3,366,379	-$ 2,130,291	-$ 221,987	$ 10,596	-$ 2,341,682	$ 1,024,697
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 3,191,281			$ 3,191,281	-$ 1,628,300	-$ 95,992		-$ 1,724,293	$ 1,466,988
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 18,163			$ 18,163	-$ 15,872	-$ 1,530		-$ 17,402	$ 761
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 285,882	$ 39,044	-$ 48,292	$ 276,633	-$ 147,816	-$ 42,586	$ 48,292	-$ 142,109	$ 134,524
10	1930	Transportation Equipment	$ 2,344,565	$ 361,328	-$ 29,127	$ 2,676,765	-$ 960,694	-$ 173,353	$ 29,127	-$ 1,104,920	$ 1,571,845
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 174,330			$ 174,330	-$ 109,488	-$ 9,530		-$ 119,018	$ 55,313
8	1945	Measurement & Testing Equipment	$ 40,825	$ 3,762		$ 44,587	-$ 24,751	-$ 2,814		-$ 27,565	$ 17,021
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 303,435	$ 12,000		$ 315,435	-$ 269,070	-$ 3,379		-$ 272,449	$ 42,986
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 170,574	-$ 11,128		-$ 181,702	$ 133,533
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,077,993	$ 240,261		$ 1,318,254	-$ 739,632	-$ 31,570		-$ 771,202	$ 547,052
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 2,419,011	-$ 727,677		-$ 3,146,689	$ 168,085	$ 84,260		$ 252,345	-$ 2,894,344
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 68,659,139**	**$ 3,240,432**	**-$ 157,794**	**$ 71,741,776**	**-$ 34,728,457**	**-$ 1,725,463**	**$ 108,132**	**-$ 36,345,789**	**$ 35,395,988**
		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	**$ 68,659,139**	**$ 3,240,432**	**-$ 157,794**	**$ 71,741,776**	**-$ 34,728,457**	**-$ 1,725,463**	**$ 108,132**	**-$ 36,345,789**	**$ 35,395,988**
		Construction Work In Progress	$ 6,218	$ 59,471		$ 65,690				$ -	$ 65,690
		Total PP&E	**$ 68,665,357**	**$ 3,299,903**	**-$ 157,794**	**$ 71,807,466**	**-$ 34,728,457**	**-$ 1,725,463**	**$ 108,132**	**-$ 36,345,789**	**$ 35,461,678**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,725,463**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 1,725,463**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
Year 2022

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)	$ 877,919	$ 7,854		$ 885,773	-$ 462,426	-$ 147,885		-$ 610,311	$ 275,462
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 65,392	-$ 640		-$ 66,032	$ 4,264
N/A	1805	Land	$ 155,686			$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 101,761			$ 101,761	-$ 70,138	-$ 1,495		-$ 71,633	$ 30,127
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 171,559	-$ 14,857		-$ 186,416	$ 280,943
47	1820	Distribution Station Equipment <50 kV	$ 4,795,989	$ 792,112		$ 5,588,101	-$ 2,727,023	-$ 116,167		-$ 2,843,190	$ 2,744,911
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 13,669,354	$ 1,187,970		$ 14,857,323	-$ 2,886,629	-$ 274,049		-$ 3,160,678	$ 11,696,646
47	1835	Overhead Conductors & Devices	$ 15,209,031	$ 326,198		$ 15,535,229	-$ 9,579,110	-$ 173,573		-$ 9,752,683	$ 5,782,547
47	1840	Underground Conduit	$ 2,633,160	$ 63,435		$ 2,696,595	-$ 429,724	-$ 52,029		-$ 481,753	$ 2,214,842
47	1845	Underground Conductors & Devices	$ 14,266,689	$ 470,514		$ 14,737,203	-$ 8,867,100	-$ 274,923		-$ 9,142,023	$ 5,595,179
47	1850	Line Transformers	$ 9,967,659	$ 727,230	-$ 8,268	$ 10,686,620	-$ 4,301,069	-$ 204,439	$ 5,002	-$ 4,500,507	$ 6,186,113
47	1855	Services (Overhead & Underground)	$ 946,477	$ 41,253		$ 987,731	-$ 304,362	-$ 22,993		-$ 327,355	$ 660,376
47	1860	Meters	$ 3,366,379	$ 111,558	-$ 27,970	$ 3,449,968	-$ 2,341,682	-$ 227,299	$ 19,062	-$ 2,549,920	$ 900,048
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 3,191,281			$ 3,191,281	-$ 1,724,293	-$ 93,897		-$ 1,818,190	$ 1,373,091
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 18,163			$ 18,163	-$ 17,402	-$ 692		-$ 18,093	$ 70
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 276,633	$ 8,986		$ 285,619	-$ 142,109	-$ 46,220		-$ 188,329	$ 97,290
10	1930	Transportation Equipment	$ 2,676,765	$ 49,859	-$ 46,331	$ 2,680,294	-$ 1,104,920	-$ 193,291	$ 46,331	-$ 1,251,881	$ 1,428,413
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 174,330			$ 174,330	-$ 119,018	-$ 9,530		-$ 128,548	$ 45,783
8	1945	Measurement & Testing Equipment	$ 44,587			$ 44,587	-$ 27,565	-$ 2,619		-$ 30,184	$ 14,403
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 315,435	$ 52,738		$ 368,173	-$ 272,449	-$ 8,346		-$ 280,794	$ 87,378
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 181,702	-$ 11,128		-$ 192,830	$ 122,406
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,318,254	$ 294,582		$ 1,612,836	-$ 771,202	-$ 44,941		-$ 816,143	$ 796,693
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 3,146,689	-$ 647,121		-$ 3,793,809	$ 252,345	$ 102,401		$ 354,745	-$ 3,439,064
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 71,741,776**	**$ 3,487,168**	**-$ 82,569**	**$ 75,146,376**	**-$ 36,345,789**	**-$ 1,818,611**	**$ 70,394**	**-$ 38,094,006**	**$ 37,052,370**
		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	**$ 71,741,776**	**$ 3,487,168**	**-$ 82,569**	**$ 75,146,376**	**-$ 36,345,789**	**-$ 1,818,611**	**$ 70,394**	**-$ 38,094,006**	**$ 37,052,370**
		Construction Work In Progress	$ 65,690	-$ 12,530	$ -	$ 53,160				$ -	$ 53,160
		Total PP&E	**$ 71,807,466**	**$ 3,474,638**	**-$ 82,569**	**$ 75,199,536**	**-$ 36,345,789**	**-$ 1,818,611**	**$ 70,394**	**-$ 38,094,006**	**$ 37,105,530**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,818,611**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 1,818,611**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
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)	$ 885,773	$ 35,450		$ 921,223	-$ 610,311	-$ 139,560		-$ 749,871	$ 171,352
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 66,032	-$ 640		-$ 66,672	$ 3,624
N/A	1805	Land	$ 155,686			$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 101,761			$ 101,761	-$ 71,633	-$ 1,495		-$ 73,128	$ 28,632
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 186,416	-$ 14,857		-$ 201,273	$ 266,086
47	1820	Distribution Station Equipment <50 kV	$ 5,588,101	$ 41,215		$ 5,629,316	-$ 2,843,190	-$ 128,722		-$ 2,971,912	$ 2,657,404
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 14,857,323	$ 1,382,763		$ 16,240,086	-$ 3,160,678	-$ 299,758		-$ 3,460,435	$ 12,779,651
47	1835	Overhead Conductors & Devices	$ 15,535,229	$ 439,307		$ 15,974,536	-$ 9,752,683	-$ 181,228		-$ 9,933,911	$ 6,040,626
47	1840	Underground Conduit	$ 2,696,595	$ 258,409		$ 2,955,004	-$ 481,753	-$ 55,247		-$ 537,000	$ 2,418,005
47	1845	Underground Conductors & Devices	$ 14,737,203	$ 1,151,098		$ 15,888,300	-$ 9,142,023	-$ 300,647		-$ 9,442,671	$ 6,445,630
47	1850	Line Transformers	$ 10,686,620	$ 711,918	-$ 4,307	$ 11,394,231	-$ 4,500,507	-$ 222,280	$ 2,840	-$ 4,719,947	$ 6,674,284
47	1855	Services (Overhead & Underground)	$ 987,731	$ 222,096		$ 1,209,827	-$ 327,355	-$ 26,285		-$ 353,640	$ 856,187
47	1860	Meters	$ 3,449,968	$ 315,961	-$ 25,265	$ 3,740,664	-$ 2,549,920	-$ 240,495	$ 19,565	-$ 2,770,849	$ 969,814
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 3,191,281	$ 36,404		$ 3,227,685	-$ 1,818,190	-$ 93,015		-$ 1,911,205	$ 1,316,480
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 18,163			$ 18,163	-$ 18,093	-$ 70		-$ 18,163	-$ 0
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 285,619	$ 34,040		$ 319,659	-$ 188,329	-$ 50,501		-$ 238,830	$ 80,829
10	1930	Transportation Equipment	$ 2,680,294	$ 64,388	-$ 17,988	$ 2,726,693	-$ 1,251,881	-$ 184,468	$ 17,988	-$ 1,418,361	$ 1,308,333
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 174,330			$ 174,330	-$ 128,548	-$ 9,530		-$ 138,077	$ 36,253
8	1945	Measurement & Testing Equipment	$ 44,587			$ 44,587	-$ 30,184	-$ 2,414		-$ 32,597	$ 11,989
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 368,173			$ 368,173	-$ 280,794	-$ 12,112		-$ 292,907	$ 75,266
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 192,830	-$ 11,128		-$ 203,958	$ 111,278
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,612,836	$ 131,727		$ 1,744,563	-$ 816,143	-$ 55,672		-$ 871,815	$ 872,748
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 3,793,809	-$ 1,232,600		-$ 5,026,409	$ 354,745	$ 127,938		$ 482,683	-$ 4,543,726
47	2440	Deferred Revenue[5]	$ -			$ -	$ -			$ -	$ -
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 75,146,376**	**$ 3,592,176**	**-$ 47,560**	**$ 78,690,993**	**-$ 38,094,006**	**-$ 1,902,187**	**$ 40,393**	**-$ 39,955,800**	**$ 38,735,193**
		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	**$ 75,146,376**	**$ 3,592,176**	**-$ 47,560**	**$ 78,690,993**	**-$ 38,094,006**	**-$ 1,902,187**	**$ 40,393**	**-$ 39,955,800**	**$ 38,735,193**
		Construction Work In Progress	$ 53,160	$ 79,305	$ -	$ 132,465				$ -	$ 132,465
		Total PP&E	**$ 75,199,536**	**$ 3,671,482**	**-$ 47,560**	**$ 78,823,458**	**-$ 38,094,006**	**-$ 1,902,187**	**$ 40,393**	**-$ 39,955,800**	**$ 38,867,658**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,902,187**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	
			Net Depreciation	**-$ 1,902,187**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
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)	$ 921,223			$ 921,223	-$ 749,871	-$ 104,874		-$ 854,745	$ 66,478
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 66,672	-$ 640		-$ 67,312	$ 2,984
N/A	1805	Land	$ 155,686			$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 101,761			$ 101,761	-$ 73,128	-$ 1,495		-$ 74,624	$ 27,137
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 201,273	-$ 14,857		-$ 216,129	$ 251,229
47	1820	Distribution Station Equipment <50 kV	$ 5,629,316			$ 5,629,316	-$ 2,971,912	-$ 128,368		-$ 3,100,280	$ 2,529,036
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 16,240,086	$ 1,609,020		$ 17,849,106	-$ 3,460,435	-$ 329,675		-$ 3,790,111	$ 14,058,995
47	1835	Overhead Conductors & Devices	$ 15,974,536	$ 850,830		$ 16,825,366	-$ 9,933,911	-$ 194,129		-$ 10,128,040	$ 6,697,326
47	1840	Underground Conduit	$ 2,955,004	$ 27,500		$ 2,982,504	-$ 537,000	-$ 58,106		-$ 595,106	$ 2,387,399
47	1845	Underground Conductors & Devices	$ 15,888,300	$ 1,267,250		$ 17,155,550	-$ 9,442,671	-$ 337,946		-$ 9,780,616	$ 7,374,934
47	1850	Line Transformers	$ 11,394,231	$ 784,780		$ 12,179,011	-$ 4,719,947	-$ 240,988		-$ 4,960,935	$ 7,218,077
47	1855	Services (Overhead & Underground)	$ 1,209,827	$ 45,000		$ 1,254,827	-$ 353,640	-$ 29,624		-$ 383,264	$ 871,563
47	1860	Meters	$ 3,740,664	$ 150,000		$ 3,890,664	-$ 2,770,849	-$ 208,734		-$ 2,979,583	$ 911,081
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 3,227,685	$ 389,630		$ 3,617,315	-$ 1,911,205	-$ 104,053		-$ 2,015,258	$ 1,602,057
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 18,163	$ 20,000		$ 38,163	-$ 18,163	-$ 1,000		-$ 19,163	$ 19,000
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 319,659	$ 27,640		$ 347,299	-$ 238,830	-$ 42,929		-$ 281,760	$ 65,540
10	1930	Transportation Equipment	$ 2,726,693	$ 65,000		$ 2,791,693	-$ 1,418,361	-$ 189,091		-$ 1,607,452	$ 1,184,242
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 174,330	$ 10,300		$ 184,630	-$ 138,077	-$ 9,938		-$ 148,015	$ 36,615
8	1945	Measurement & Testing Equipment	$ 44,587	$ 22,500		$ 67,087	-$ 32,597	-$ 3,539		-$ 36,136	$ 30,951
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 368,173			$ 368,173	-$ 292,907	-$ 11,592		-$ 304,499	$ 63,674
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 203,958	-$ 11,128		-$ 215,086	$ 100,150
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,744,563	$ 160,000		$ 1,904,563	-$ 871,815	-$ 63,123		-$ 934,938	$ 969,625
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 5,026,409	-$ 1,720,463		-$ 6,746,872	$ 482,683	$ 167,749		$ 650,432	-$ 6,096,440
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 78,690,993**	**$ 3,708,987**	**$ -**	**$ 82,399,980**	**-$ 39,955,800**	**-$ 1,918,080**	**$ -**	**-$ 41,873,880**	**$ 40,526,100**
		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	**$ 78,690,993**	**$ 3,708,987**	**$ -**	**$ 82,399,980**	**-$ 39,955,800**	**-$ 1,918,080**	**$ -**	**-$ 41,873,880**	**$ 40,526,100**
		Construction Work In Progress	$ 132,465			$ 132,465				$ -	$ 132,465
		Total PP&E	**$ 78,823,458**	**$ 3,708,987**	**$ -**	**$ 82,532,445**	**-$ 39,955,800**	**-$ 1,918,080**	**$ -**	**-$ 41,873,880**	**$ 40,658,565**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 1,918,080**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 167,749
			Net Depreciation	**-$ 2,085,829**

Appendix 2-C – (OEB Appendix 2-BA - Fixed Asset Continuity Schedules)

Accounting Standard MIFRS
Year 2025

			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)	$ 921,223			$ 921,223	-$ 854,745	-$ 39,838		-$ 894,583	$ 26,640
CEC	1612	Land Rights (Formally known as Account 1906)	$ 70,296			$ 70,296	-$ 67,312	-$ 640		-$ 67,953	$ 2,343
N/A	1805	Land	$ 155,686			$ 155,686	-$ 1,236			-$ 1,236	$ 154,450
47	1808	Buildings	$ 101,761			$ 101,761	-$ 74,624	-$ 1,495		-$ 76,119	$ 25,642
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 467,359			$ 467,359	-$ 216,129	-$ 13,523		-$ 229,653	$ 237,706
47	1820	Distribution Station Equipment <50 kV	$ 5,629,316	$ 360,000		$ 5,989,316	-$ 3,100,280	-$ 133,622		-$ 3,233,902	$ 2,755,414
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 17,849,106	$ 931,387		$ 18,780,493	-$ 3,790,111	-$ 355,079		-$ 4,145,190	$ 14,635,303
47	1835	Overhead Conductors & Devices	$ 16,825,366	$ 362,194		$ 17,187,560	-$ 10,128,040	-$ 206,260		-$ 10,334,300	$ 6,853,261
47	1840	Underground Conduit	$ 2,982,504	$ 82,500		$ 3,065,004	-$ 595,106	-$ 59,206		-$ 654,312	$ 2,410,692
47	1845	Underground Conductors & Devices	$ 17,155,550	$ 1,463,500		$ 18,619,050	-$ 9,780,616	-$ 381,640		-$ 10,162,256	$ 8,456,794
47	1850	Line Transformers	$ 12,179,011	$ 1,060,036		$ 13,239,047	-$ 4,960,935	-$ 264,048		-$ 5,224,983	$ 8,014,065
47	1855	Services (Overhead & Underground)	$ 1,254,827	$ 46,350		$ 1,301,177	-$ 383,264	-$ 30,766		-$ 414,030	$ 887,147
47	1860	Meters	$ 3,973,374	$ 154,500		$ 4,127,874	-$ 3,015,424	-$ 130,162		-$ 3,145,587	$ 982,287
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ 3,617,315	$ 125,000		$ 3,742,315	-$ 2,015,258	-$ 115,442		-$ 2,130,700	$ 1,611,615
13	1910	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 38,163	$ 50,000		$ 88,163	-$ 19,163	-$ 4,500		-$ 23,663	$ 64,500
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ -			$ -	$ -
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 347,299	$ 140,000		$ 487,299	-$ 281,760	-$ 41,179		-$ 322,938	$ 164,361
10	1930	Transportation Equipment	$ 2,791,693	$ 661,436		$ 3,453,129	-$ 1,607,452	-$ 203,597		-$ 1,811,048	$ 1,642,081
8	1935	Stores Equipment	$ 30,023			$ 30,023	-$ 30,023			-$ 30,023	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 184,630	$ 10,609		$ 195,239	-$ 148,015	-$ 10,876		-$ 158,891	$ 36,348
8	1945	Measurement & Testing Equipment	$ 67,087	$ 100,000		$ 167,087	-$ 36,136	-$ 8,580		-$ 44,716	$ 122,370
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 368,173			$ 368,173	-$ 304,499	-$ 11,072		-$ 315,571	$ 52,602
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ 315,235			$ 315,235	-$ 215,086	-$ 11,128		-$ 226,213	$ 89,022
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,904,563	$ 242,050		$ 2,146,613	-$ 934,938	-$ 73,343		-$ 1,008,281	$ 1,138,332
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 6,746,872	-$ 974,149		-$ 7,721,021	$ 650,432	$ 204,589		$ 855,020	-$ 6,866,001
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 82,482,690**	**$ 4,815,413**	**$ -**	**$ 87,298,103**	**-$ 41,909,721**	**-$ 1,891,407**	**$ -**	**-$ 43,801,128**	**$ 43,496,974**
		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	**$ 82,482,690**	**$ 4,815,413**	**$ -**	**$ 87,298,103**	**-$ 41,909,721**	**-$ 1,891,407**	**$ -**	**-$ 43,801,128**	**$ 43,496,974**
		Construction Work In Progress	$ 132,465	-$ 132,465	$ -	$ -				$ -	$ -
		Total PP&E	**$ 82,615,155**	**$ 4,682,948**	**$ -**	**$ 87,298,103**	**-$ 41,909,721**	**-$ 1,891,407**	**$ -**	**-$ 43,801,128**	**$ 43,496,974**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 1,891,407**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	$ 204,589
			Net Depreciation	**-$ 2,095,996**

Appendix 2-D: OEB Appendix 2-C Depreciation and Amortization Expense

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2017

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]	Depreciation Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets,	Variance [4]
		a	b	c	d	e = 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)	$ 966,997	$ 509,821	$ 126,550	$ -	$ 520,450	5.00	20.00%	**$ 104,090**	$ 104,090	**$ 0**
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	**$ 640**	$ 640	**$ -**
1805	Land	$ 158,686		$ -	$ -	$ 158,686	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 96,568	$ 22,434	$ -	$ -	$ 74,134	60.00	1.67%	**$ 1,236**	$ 1,236	**$ -**
1810	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 467,359		$ -	$ -	$ 467,359	31.46	3.18%	**$ 14,857**	$ 14,857	**-$ 0**
1820	Distribution Station Equipment <50 kV	$ 4,491,261	$ 708,465	$ 3,000	$ 269,283	$ 3,515,013	39.25	2.55%	**$ 89,556**	$ 89,556	**-$ 0**
1825	Storage Battery Equipment	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 9,991,568	$ 568,089	$ 600,349	$ -	$ 9,723,654	50.00	2.00%	**$ 194,473**	$ 194,473	**$ -**
1835	Overhead Conductors & Devices	$ 13,762,667	$ 6,696,157	$ 180,579	$ -	$ 7,156,800	50.00	2.00%	**$ 143,136**	$ 143,136	**$ 0**
1840	Underground Conduit	$ 1,542,830	$ 63,448	$ 462,310	$ -	$ 1,710,536	50.00	2.00%	**$ 34,211**	$ 34,211	**$ -**
1845	Underground Conductors & Devices	$ 11,436,604	$ 5,901,093	$ 243,987	$ -	$ 5,657,505	30.00	3.33%	**$ 188,584**	$ 188,584	**$ 0**
1850	Line Transformers	$ 7,198,277	$ 2,192,288	$ 357,028	$ 18,989	$ 5,165,514	40.00	2.50%	**$ 129,138**	$ 129,138	**-$ 0**
1855	Services (Overhead & Underground)	$ 855,562	$ 47,371	$ 10,720	$ -	$ 813,550	40.00	2.50%	**$ 20,339**	$ 20,339	**-$ 0**
1860	Meters	$ 3,071,875	$ 38,777	$ 73,499	$ 53,113	$ 3,016,734	14.75	6.78%	**$ 204,560**	$ 204,560	**$ 0**
1860	Meters (Smart Meters)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,635,551	$ 535,937	$ 93,230	$ -	$ 2,146,229	31.75	3.15%	**$ 67,598**	$ 67,598	**-$ 0**
1910	Leasehold Improvements	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 90,445	$ 51,482	$ -	$ -	$ 38,964	10.00	10.00%	**$ 3,896**	$ 3,896	**-$ 0**
1915	Office Furniture & Equipment (5 years)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 234,822	$ 29,372	$ 13,810	$ -	$ 212,355	4.00	25.00%	**$ 53,089**	$ 53,089	**$ -**
1930	Transportation Equipment	$ 2,178,574	$ 453,511	$ 73,276	$ 254,812	$ 1,506,889	13.71	7.29%	**$ 109,892**	$ 109,892	**-$ 0**
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	**$ 0**	$ -	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 100,814	$ 45,031	$ 50,994	$ -	$ 81,280	10.00	10.00%	**$ 8,128**	$ 8,128	**$ 0**
1945	Measurement & Testing Equipment	$ 20,451	$ 12,739	$ -	$ -	$ 7,712	10.00	10.00%	**$ 771**	$ 771	**-$ 0**
1950	Power Operated Equipment	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 298,231	$ 11,454	$ -	$ -	$ 286,778	10.00	10.00%	**$ 28,678**	$ 28,678	**$ 0**
1955	Communication Equipment (Smart Meters)	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	**$ 11,128**	$ 11,128	**$ -**
1970	Load Management Controls Customer Premises	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 779,964	$ 6,334	$ 28,500	$ -	$ 787,880	18.00	5.56%	**$ 43,771**	$ 43,771	**$ 0**
1985	Miscellaneous Fixed Assets	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 718,435	$ 169,333	-$ 36,018	$ -	-$ 905,777	40.00	2.50%	**-$ 22,644**	-$ 22,644	**-$ 0**
2440	Deferred Revenue	$ -			$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 60,076,227**	**$ 18,184,497**	**$ 2,281,816**	**$ 596,198**	**$ 42,436,440**	**$ 618**		**$ 1,429,125**	**$ 1,429,125**	**-$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2018

		Book Values				Service Lives		Depreciation 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,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = 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)	$ 1,093,547	$ 365,482	$ -	$ -	$ 728,065	5.00	20.00%	**$ 145,613**	$ 145,613	**-$ 0**
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	**$ 640**	$ 640	**$ -**
1805	Land	$ 158,686	$ -	$ -	$ -	$ 158,686	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 96,568	$ 22,434	$ -	$ -	$ 74,134	60.00	1.67%	**$ 1,236**	$ 1,236	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 467,359	$ -	$ -	$ -	$ 467,359	31.46	3.18%	**$ 14,857**	$ 14,857	**-$ 0**
1820	Distribution Station Equipment <50 kV	$ 4,224,978	$ 923,195	$ 228,181	$ -	$ 3,415,873	39.25	2.55%	**$ 87,030**	$ 87,030	**-$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 10,591,918	$ 560,816	$ 707,453	$ -	$ 10,384,828	50.00	2.00%	**$ 207,697**	$ 207,697	**$ -**
1835	Overhead Conductors & Devices	$ 13,943,246	$ 6,693,483	$ 81,248	$ -	$ 7,290,387	50.00	2.00%	**$ 145,808**	$ 145,808	**$ -**
1840	Underground Conduit	$ 2,005,139	$ 63,448	$ 73,039	$ -	$ 1,978,210	50.00	2.00%	**$ 39,564**	$ 39,564	**-$ 0**
1845	Underground Conductors & Devices	$ 11,680,592	$ 5,901,093	$ 242,240	$ -	$ 5,900,619	30.00	3.33%	**$ 196,687**	$ 196,687	**$ 0**
1850	Line Transformers	$ 7,536,316	$ 2,136,577	$ 303,002	$ 42,184	$ 5,509,056	40.00	2.50%	**$ 137,726**	$ 137,726	**-$ 0**
1855	Services (Overhead & Underground)	$ 866,282	$ 47,371	$ 47,970	$ -	$ 842,895	40.00	2.50%	**$ 21,072**	$ 21,072	**-$ 0**
1860	Meters	$ 3,092,261	$ 41,541	$ 100,332	$ 9,672	$ 3,091,214	14.75	6.78%	**$ 209,611**	$ 209,611	**-$ 0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,728,781	$ 540,429	$ 107,804	$ -	$ 2,242,254	31.75	3.15%	**$ 70,622**	$ 70,622	**$ 0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 90,445	$ 68,011	$ -	$ -	$ 22,434	10.00	10.00%	**$ 2,243**	$ 2,243	**$ 0**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 248,633	$ 74,761	$ -	$ -	$ 173,871	4.00	25.00%	**$ 43,468**	$ 43,468	**-$ 0**
1930	Transportation Equipment	$ 1,997,038	$ 176,088	$ 220,016	$ 209,354	$ 1,721,604	13.71	7.29%	**$ 125,550**	$ 125,550	**-$ 0**
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	**$ 0**	$ -	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 151,808	$ 56,513	$ -	$ 2,941	$ 92,354	10.00	10.00%	**$ 9,235**	$ 9,235	**$ -**
1945	Measurement & Testing Equipment	$ 20,451	$ 13,560	$ 20,374	$ -	$ 17,077	10.00	10.00%	**$ 1,708**	$ 1,708	**-$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 298,231	$ 132,097	$ -	$ -	$ 166,135	10.00	10.00%	**$ 16,613**	$ 16,613	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	**$ 11,128**	$ 11,128	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 808,464	$ 309,998	$ 54,389	$ -	$ 525,661	18.00	5.56%	**$ 29,203**	$ 29,203	**$ 0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 754,453	$ 182,379	-$ 170,518	$ -	-$ 1,022,091	40.00	2.50%	**-$ 25,552**	-$ 25,552	**-$ 0**
2440	Deferred Revenue	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 61,761,845**	**$ 18,430,638**	**$ 2,015,531**	**$ 264,151**	**$ 44,074,821**	**$ 618**		**$ 1,491,760**	**$ 1,491,760**	**-$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2019

Account	Description	**Book Values**				**Service Lives**		**Depreciation 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,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = 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)	$ 1,093,547	$ 579,923	$ 382,313	$ -	$ 704,780	5.00	20.00%	**$ 140,956**	$ 140,956	**-$ 0**
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	**$ 640**	$ 640	**$ -**
1805	Land	$ 158,686	$ -	$ -	$ 3,000	$ 155,686	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 96,568	$ 22,434	$ -	$ -	$ 74,134	60.00	1.67%	**$ 1,236**	$ 1,236	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 467,359	$ -	$ -	$ -	$ 467,359	31.46	3.18%	**$ 14,857**	$ 14,857	**-$ 0**
1820	Distribution Station Equipment <50 kV	$ 4,453,159	$ 758,947	$ 214,481	$ 89,718	$ 3,711,734	39.25	2.55%	**$ 94,568**	$ 94,568	**$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 11,299,371	$ 560,816	$ 716,853	$ -	$ 11,096,981	50.00	2.00%	**$ 221,940**	$ 221,940	**$ 0**
1835	Overhead Conductors & Devices	$ 14,024,494	$ 6,693,483	$ 124,433	$ -	$ 7,393,228	50.00	2.00%	**$ 147,865**	$ 147,865	**-$ 0**
1840	Underground Conduit	$ 2,078,178	$ 63,448	$ 67,831	$ -	$ 2,048,645	50.00	2.00%	**$ 40,973**	$ 40,973	**-$ 0**
1845	Underground Conductors & Devices	$ 11,922,832	$ 5,901,093	$ 377,332	$ -	$ 6,210,405	30.00	3.33%	**$ 207,014**	$ 207,014	**-$ 0**
1850	Line Transformers	$ 7,797,133	$ 2,082,517	$ 753,899	$ 54,059	$ 6,037,506	40.00	2.50%	**$ 150,938**	$ 150,938	**$ -**
1855	Services (Overhead & Underground)	$ 914,252	$ 47,371	$ 14,227	$ -	$ 873,994	40.00	2.50%	**$ 21,850**	$ 21,850	**-$ 0**
1860	Meters	$ 3,182,921	$ 15,728	$ 63,328	$ 29,546	$ 3,169,311	14.75	6.78%	**$ 214,906**	$ 214,906	**-$ 0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 2,836,585	$ 328,800	$ 345,645	$ -	$ 2,680,608	31.75	3.15%	**$ 84,429**	$ 84,429	**$ 0**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 90,445	$ -	$ -	$ 72,282	$ 18,163	10.00	10.00%	**$ 1,816**	$ 1,816	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 248,633	$ 178,829	$ 148,293	$ -	$ 143,950	4.00	25.00%	**$ 35,988**	$ 35,988	**$ -**
1930	Transportation Equipment	$ 2,007,700	$ 63,442	$ 459,036	$ 153,526	$ 2,020,250	13.71	7.29%	**$ 147,329**	$ 147,329	**$ -**
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	**$ 0**	$ -	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 148,867	$ 70,649	$ 21,063	$ -	$ 88,750	10.00	10.00%	**$ 8,875**	$ 8,875	**$ -**
1945	Measurement & Testing Equipment	$ 40,825	$ 13,560	$ -	$ -	$ 27,264	10.00	10.00%	**$ 2,726**	$ 2,726	**-$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 298,231	$ 128,312	$ 7,568	$ -	$ 173,703	10.00	10.00%	**$ 17,370**	$ 17,370	**-$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	**$ 11,128**	$ 11,128	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 862,853	$ 341,689	$ 75,651	$ -	$ 558,989	18.00	5.56%	**$ 31,055**	$ 31,055	**-$ 0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 924,971	$ 233,064	-$ 357,264	$ -	-$ 1,336,667	40.00	2.50%	**-$ 33,417**	-$ 33,417	**$ -**
2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 63,513,224**	**$ 18,205,468**	**$ 3,414,689**	**$ 402,131**	**$ 46,612,970**	**$ 618**		**$ 1,565,041**	**$ 1,565,041**	**$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2020

		Book Values				**Service Lives**		**Depreciation 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,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = 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)	$ 1,475,860	$ 69,595	$ 287,678	$ 897,399	$ 652,704	5.00	20.00%	**$ 130,541**	$ 130,541	**$ 0**
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	**$ 640**	$ 640	**$ -**
1805	Land	$ 155,686	$ -	$ -	$ -	$ 155,686	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 96,568	$ 22,276	$ -	$ -	$ 74,292	60.00	1.67%	**$ 1,238**	$ 1,238	**$ -**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 467,359	$ -	$ -	$ -	$ 467,359	31.46	3.18%	**$ 14,857**	$ 14,858	**$ 1**
1820	Distribution Station Equipment <50 kV	$ 4,577,922	$ 741,801	$ 309,643	$ 71,022	$ 3,919,920	39.25	2.55%	**$ 99,872**	$ 99,872	**-$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 12,016,224	$ 560,906	$ 615,168	$ -	$ 11,762,902	50.00	2.00%	**$ 235,258**	$ 235,258	**$ -**
1835	Overhead Conductors & Devices	$ 14,148,927	$ 6,693,545	$ 457,830	$ -	$ 7,684,298	50.00	2.00%	**$ 153,686**	$ 153,686	**$ -**
1840	Underground Conduit	$ 2,146,009	$ 63,448	$ 338,322	$ -	$ 2,251,722	50.00	2.00%	**$ 45,034**	$ 45,034	**-$ 0**
1845	Underground Conductors & Devices	$ 12,300,164	$ 6,158,223	$ 1,222,095	$ -	$ 6,752,989	30.00	3.33%	**$ 225,100**	$ 225,100	**$ 0**
1850	Line Transformers	$ 8,496,973	$ 2,126,751	$ 903,514	$ 32,135	$ 6,789,844	40.00	2.50%	**$ 169,746**	$ 169,746	**$ -**
1855	Services (Overhead & Underground)	$ 928,479	$ 47,371	$ 26,655	$ -	$ 894,435	40.00	2.50%	**$ 22,361**	$ 22,361	**$ 0**
1860	Meters	$ 3,216,703	$ 51,745	$ 48,816	$ 9,917	$ 3,179,449	14.75	6.78%	**$ 215,594**	$ 215,594	**$ -**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 3,182,230	$ 131,815	$ 9,052	$ -	$ 3,054,941	31.75	3.15%	**$ 96,219**	$ 96,219	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 18,163		$ -	$ -	$ 18,163	10.00	10.00%	**$ 1,816**	$ 1,816	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 396,926	$ 111,866	$ 35,725	$ 146,769	$ 156,153	4.00	25.00%	**$ 39,038**	$ 39,038	**$ 0**
1930	Transportation Equipment	$ 2,313,210	$ 92,019	$ 31,355	$ -	$ 2,236,868	13.71	7.29%	**$ 163,127**	$ 163,127	**$ -**
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	**$ 0**	$ -	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 169,930	$ 77,556	$ 4,400	$ -	$ 94,574	10.00	10.00%	**$ 9,457**	$ 9,457	**-$ 0**
1945	Measurement & Testing Equipment	$ 40,825	$ 13,560	$ -	$ -	$ 27,264	10.00	10.00%	**$ 2,726**	$ 2,726	**-$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 305,800	$ 130,441	-$ 2,365	$ -	$ 174,176	10.00	10.00%	**$ 17,418**	$ 17,418	**$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	**$ 11,128**	$ 11,128	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 938,504	$ 481,686	$ 139,489	$ -	$ 526,563	18.00	5.56%	**$ 29,253**	$ 29,253	**$ 0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 1,282,235	$ 394,292	-$ 1,136,776	$ -	-$ 2,244,915	40.00	2.50%	**-$ 56,123**	-$ 56,123	**$ 0**
2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 66,525,782**	**$ 18,090,257**	**$ 3,290,599**	**$ 1,157,242**	**$ 48,923,583**	**$ 618**		**$ 1,627,987**	**$ 1,627,988**	**$ 1**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2021

		Book Values				Service Lives		Depreciation 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,**	**Variance [4]**
		a	**b**	**c**	**d**	**e = 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)	$ 866,138	$ 68,125	$ 11,781	$ -	$ 803,904	5.00	20.00%	$ 160,781	$ 160,781	$ 0
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	$ 640	$ 640	$ -
1805	Land	$ 155,686	$ -	$ -	$ -	$ 155,686	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ 96,568	$ 9,452	$ 5,193	$ -	$ 89,713	60.00	1.67%	$ 1,495	$ 1,495	$ -
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 467,359	$ 0	$ -	$ -	$ 467,359	31.46	3.18%	$ 14,857	$ 14,857	$ 0
1820	Distribution Station Equipment <50 kV	$ 4,816,542	$ 647,273	$ 33,456	$ 54,009	$ 4,131,988	39.25	2.55%	$ 105,275	$ 105,275	-$ 0
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 12,631,392	$ 560,825	$ 1,037,962	$ -	$ 12,589,548	50.00	2.00%	$ 251,791	$ 251,791	$ -
1835	Overhead Conductors & Devices	$ 14,606,758	$ 6,693,483	$ 602,273	$ -	$ 8,214,411	50.00	2.00%	$ 164,288	$ 164,288	$ -
1840	Underground Conduit	$ 2,484,331	$ 63,448	$ 148,829	$ -	$ 2,495,297	50.00	2.00%	$ 49,906	$ 49,906	$ 0
1845	Underground Conductors & Devices	$ 13,522,260	$ 6,203,570	$ 744,429	$ -	$ 7,690,904	30.00	3.33%	$ 256,363	$ 256,363	-$ 0
1850	Line Transformers	$ 9,368,352	$ 2,147,298	$ 610,941	$ 11,634	$ 7,514,890	40.00	2.50%	$ 187,872	$ 187,872	$ 0
1855	Services (Overhead & Underground)	$ 955,134	$ 47,371	-$ 8,657	$ -	$ 903,434	40.00	2.50%	$ 22,586	$ 22,586	-$ 0
1860	Meters	$ 3,255,602	$ 29,894	$ 125,509	$ 14,732	$ 3,273,731	14.75	6.78%	$ 221,987	$ 221,987	-$ 0
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 3,191,281	$ 143,520	$ -	$ -	$ 3,047,762	31.75	3.15%	$ 95,992	$ 95,992	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 18,163	$ 2,868	$ -	$ -	$ 15,296	10.00	10.00%	$ 1,530	$ 1,530	-$ 0
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 285,882	$ 86,769	$ 39,044	$ 48,292	$ 170,342	4.00	25.00%	$ 42,586	$ 42,586	$ 0
1930	Transportation Equipment	$ 2,344,565	$ 119,002	$ 361,328	$ 29,127	$ 2,377,100	13.71	7.29%	$ 173,353	$ 173,353	$ 0
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	$ 0	$ -	-$ 0
1940	Tools, Shop & Garage Equipment	$ 174,330	$ 79,032	$ -	$ -	$ 95,299	10.00	10.00%	$ 9,530	$ 9,530	$ 0
1945	Measurement & Testing Equipment	$ 40,825	$ 14,563	$ 3,762	$ -	$ 28,142	10.00	10.00%	$ 2,814	$ 2,814	-$ 0
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 303,435	$ 275,649	$ 12,000	$ -	$ 33,786	10.00	10.00%	$ 3,379	$ 3,379	-$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	$ 11,128	$ 11,128	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,077,993	$ 629,868	$ 240,261	$ -	$ 568,256	18.00	5.56%	$ 31,570	$ 31,570	$ 0
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 2,419,011	$ 587,544	-$ 727,677	$ -	-$ 3,370,394	40.00	2.50%	-$ 84,260	-$ 84,260	$ -
2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 68,659,139**	**$ 18,530,913**	**$ 3,240,432**	**$ 157,794**	**$ 51,590,647**	**$ 618**		**$ 1,725,463**	**$ 1,725,463**	**-$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2022

Account	Description	Book Values				Service Lives		Depreciation Expense			
		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,	Variance [4]
		a	b	c	d	e = 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)	$ 877,919	$ 142,420	$ 7,854	$ -	$ 739,426	5.00	20.00%	$ 147,885	$ 147,885	-$ 0
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	$ 640	$ 640	$ -
1805	Land	$ 155,686	$ -	$ -	$ -	$ 155,686	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ 101,761	$ 12,061	$ -	$ -	$ 89,700	60.00	1.67%	$ 1,495	$ 1,495	-$ 0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 467,359	$ 0	$ -	$ -	$ 467,359	31.46	3.18%	$ 14,857	$ 14,857	$ 0
1820	Distribution Station Equipment <50 kV	$ 4,795,989	$ 632,562	$ 792,112	$ -	$ 4,559,484	39.25	2.55%	$ 116,167	$ 116,167	$ 0
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 13,669,354	$ 560,906	$ 1,187,970	$ -	$ 13,702,433	50.00	2.00%	$ 274,049	$ 274,049	$ -
1835	Overhead Conductors & Devices	$ 15,209,031	$ 6,693,483	$ 326,198	$ -	$ 8,678,647	50.00	2.00%	$ 173,573	$ 173,573	$ 0
1840	Underground Conduit	$ 2,633,160	$ 63,448	$ 63,435	$ -	$ 2,601,429	50.00	2.00%	$ 52,029	$ 52,029	-$ 0
1845	Underground Conductors & Devices	$ 14,266,689	$ 6,254,255	$ 470,514	$ -	$ 8,247,691	30.00	3.33%	$ 274,923	$ 274,923	-$ 0
1850	Line Transformers	$ 9,967,659	$ 2,145,430	$ 727,230	$ 8,268	$ 8,177,576	40.00	2.50%	$ 204,439	$ 204,439	$ -
1855	Services (Overhead & Underground)	$ 946,477	$ 47,371	$ 41,253	$ -	$ 919,732	40.00	2.50%	$ 22,993	$ 22,993	$ 0
1860	Meters	$ 3,366,379	$ 42,115	$ 111,558	$ 27,970	$ 3,352,074	14.75	6.78%	$ 227,299	$ 227,299	$ -
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 3,191,281	$ 210,044	$ -	$ -	$ 2,981,237	31.75	3.15%	$ 93,897	$ 93,897	$ -
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 18,163	$ 11,248	$ -	$ -	$ 6,916	10.00	10.00%	$ 692	$ 692	$ -
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 276,633	$ 96,246	$ 8,986	$ -	$ 184,880	4.00	25.00%	$ 46,220	$ 46,220	-$ 0
1930	Transportation Equipment	$ 2,676,765	$ 4,868	$ 49,859	$ 46,331	$ 2,650,496	13.71	7.29%	$ 193,291	$ 193,291	-$ 0
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	$ 0	$ -	-$ 0
1940	Tools, Shop & Garage Equipment	$ 174,330	$ 79,032	$ -	$ -	$ 95,299	10.00	10.00%	$ 9,530	$ 9,530	-$ 0
1945	Measurement & Testing Equipment	$ 44,587	$ 18,399	$ -	$ -	$ 26,187	10.00	10.00%	$ 2,619	$ 2,619	$ 0
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 315,435	$ 258,349	$ 52,738	$ -	$ 83,455	10.00	10.00%	$ 8,346	$ 8,346	$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	$ 11,128	$ 11,128	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,318,254	$ 656,610	$ 294,582	$ -	$ 808,935	18.00	5.56%	$ 44,941	$ 44,941	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	-$ 3,146,689	$ 625,773	-$ 647,121	$ -	-$ 4,096,022	40.00	2.50%	-$ 102,401	-$ 102,401	-$ 0
2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 71,741,776**	**$ 18,675,978**	**$ 3,487,168**	**$ 82,569**	**$ 54,726,814**	**$ 618**		**$ 1,818,611**	**$ 1,818,611**	**-$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2023

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]	Depreciation Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets,	Variance [4]
		a	b	c	d	e = 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)	$ 885,773	$ 205,697	$ 35,450	$ -	$ 697,801	5.00	20.00%	**$ 139,560**	$ 139,560	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	**$ 640**	$ 640	**$ -**
1805	Land	$ 155,686	$ -	$ -	$ -	$ 155,686	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 101,761	$ 12,061	$ -	$ -	$ 89,700	60.00	1.67%	**$ 1,495**	$ 1,495	**-$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 467,359	$ 0	$ -	$ -	$ 467,359	31.46	3.18%	**$ 14,857**	$ 14,857	**$ 0**
1820	Distribution Station Equipment <50 kV	$ 5,588,101	$ 556,452	$ 41,215	$ -	$ 5,052,257	39.25	2.55%	**$ 128,722**	$ 128,722	**$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 14,857,323	$ 560,825	$ 1,382,763	$ -	$ 14,987,880	50.00	2.00%	**$ 299,758**	$ 299,758	**$ -**
1835	Overhead Conductors & Devices	$ 15,535,229	$ 6,693,483	$ 439,307	$ -	$ 9,061,400	50.00	2.00%	**$ 181,228**	$ 181,228	**$ 0**
1840	Underground Conduit	$ 2,696,595	$ 63,448	$ 258,409	$ -	$ 2,762,351	50.00	2.00%	**$ 55,247**	$ 55,247	**-$ 0**
1845	Underground Conductors & Devices	$ 14,737,203	$ 6,293,339	$ 1,151,098	$ -	$ 9,019,412	30.00	3.33%	**$ 300,647**	$ 300,647	**-$ 0**
1850	Line Transformers	$ 10,686,620	$ 2,147,074	$ 711,918	$ 4,307	$ 8,891,198	40.00	2.50%	**$ 222,280**	$ 222,280	**$ 0**
1855	Services (Overhead & Underground)	$ 987,731	$ 47,371	$ 222,096	$ -	$ 1,051,407	40.00	2.50%	**$ 26,285**	$ 26,285	**$ 0**
1860	Meters	$ 3,449,968	$ 36,008	$ 315,961	$ 25,265	$ 3,546,675	14.75	6.78%	**$ 240,495**	$ 240,495	**$ -**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 3,191,281	$ 256,242	$ 36,404	$ -	$ 2,953,241	31.75	3.15%	**$ 93,015**	$ 93,015	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 18,163	$ 17,462	$ -	$ -	$ 702	10.00	10.00%	**$ 70**	$ 70	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 285,619	$ 100,635	$ 34,040	$ -	$ 202,004	4.00	25.00%	**$ 50,501**	$ 50,501	**-$ 0**
1930	Transportation Equipment	$ 2,680,294	$ 164,986	$ 64,388	$ 17,988	$ 2,529,513	13.71	7.29%	**$ 184,468**	$ 184,468	**-$ 0**
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	**$ 0**	$ -	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 174,330	$ 79,032	$ -	$ -	$ 95,299	10.00	10.00%	**$ 9,530**	$ 9,530	**-$ 0**
1945	Measurement & Testing Equipment	$ 44,587	$ 20,451	$ -	$ -	$ 24,136	10.00	10.00%	**$ 2,414**	$ 2,414	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 368,173	$ 247,048	$ -	$ -	$ 121,125	10.00	10.00%	**$ 12,112**	$ 12,112	**-$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	**$ 11,128**	$ 11,128	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 1,612,836	$ 676,596	$ 131,727	$ -	$ 1,002,103	18.00	5.56%	**$ 55,672**	$ 55,672	**-$ 0**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	-$ 3,793,809	$ 707,391	-$ 1,232,600	$ -	-$ 5,117,500	40.00	2.50%	**-$ 127,938**	-$ 127,938	**$ 0**
2440	Deferred Revenue	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
	Total	**$ 75,146,376**	**$ 19,006,961**	**$ 3,592,176**	**$ 47,560**	**$ 57,887,943**	**$ 618**		**$ 1,902,187**	**$ 1,902,187**	**-$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2024

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]	Depreciation Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix 2-BA Fixed Assets,	Variance [4]
		a	b	c	d	e = 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)	$ 921,223	$ 396,854	$ -	$ -	$ 524,369	5.00	20.00%	$ 104,874	$ 104,874	$ -
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	$ 640	$ 640	$ 0
1805	Land	$ 155,686	$ -	$ -	$ -	$ 155,686	-	0.00%	$ -	$ -	$ -
1808	Buildings	$ 101,761	$ 12,061	$ -	$ -	$ 89,700	60.00	1.67%	$ 1,495	$ 1,495	$ 0
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 467,359	$ 0	$ -	$ -	$ 467,359	31.46	3.18%	$ 14,857	$ 14,857	-$ 0
1820	Distribution Station Equipment <50 kV	$ 5,629,316	$ 590,946	$ -	$ -	$ 5,038,371	39.25	2.55%	$ 128,368	$ 128,368	$ 0
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 16,240,086	$ 560,825	$ 1,609,020	$ -	$ 16,483,771	50.00	2.00%	$ 329,675	$ 329,675	$ 0
1835	Overhead Conductors & Devices	$ 15,974,536	$ 6,693,483	$ 850,830	$ -	$ 9,706,468	50.00	2.00%	$ 194,129	$ 194,129	$ 0
1840	Underground Conduit	$ 2,955,004	$ 63,448	$ 27,500	$ -	$ 2,905,306	50.00	2.00%	$ 58,106	$ 58,106	-$ 0
1845	Underground Conductors & Devices	$ 15,888,300	$ 6,383,552	$ 1,267,250	$ -	$ 10,138,374	30.00	3.33%	$ 337,946	$ 337,946	$ 0
1850	Line Transformers	$ 11,394,231	$ 2,147,114	$ 784,780	$ -	$ 9,639,507	40.00	2.50%	$ 240,988	$ 240,988	-$ 0
1855	Services (Overhead & Underground)	$ 1,209,827	$ 47,371	$ 45,000	$ -	$ 1,184,955	40.00	2.50%	$ 29,624	$ 29,624	-$ 0
1860	Meters	$ 3,740,664	$ 737,383	$ 150,000	$ -	$ 3,078,281	14.75	6.78%	$ 208,734	$ 208,734	-$ 0
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ 3,227,685	$ 118,817	$ 389,630	$ -	$ 3,303,683	31.75	3.15%	$ 104,053	$ 104,053	$ 0
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 18,163	$ 18,163	$ 20,000	$ -	$ 10,000	10.00	10.00%	$ 1,000	$ 1,000	$ 0
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 319,659	$ 161,762	$ 27,640	$ -	$ 171,717	4.00	25.00%	$ 42,929	$ 42,929	$ 0
1930	Transportation Equipment	$ 2,726,693	$ 166,289	$ 65,000	$ -	$ 2,592,904	13.71	7.29%	$ 189,091	$ 189,091	$ -
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	$ 0	$ -	-$ 0
1940	Tools, Shop & Garage Equipment	$ 174,330	$ 80,102	$ 10,300	$ -	$ 99,378	10.00	10.00%	$ 9,938	$ 9,938	$ -
1945	Measurement & Testing Equipment	$ 44,587	$ 20,451	$ 22,500	$ -	$ 35,386	10.00	10.00%	$ 3,539	$ 3,539	-$ 0
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 368,173	$ 252,251	$ -	$ -	$ 115,922	10.00	10.00%	$ 11,592	$ 11,592	-$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	$ 11,128	$ 11,128	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ 1,744,563	$ 688,353	$ 160,000	$ -	$ 1,136,210	18.00	5.56%	$ 63,123	$ 63,123	-$ 0
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 5,026,409	$ 823,311	-$ 1,720,463	$ -	-$ 6,709,952	40.00	2.50%	-$ 167,749	-$ 167,749	$ 0
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	$ -	$ -	$ -
	Total	**$ 78,690,993**	**$ 20,083,896**	**$ 3,708,987**	**$ -**	**$ 60,461,590**	**$ 618**		**$ 1,918,079**	**$ 1,918,080**	**$ 0**

Appendix 2-D – (OEB Appendix 2-C - Depreciation and Amortization Expense)

Year 2025

Account	Description	Book Values				Service Lives		Depreciation Expense			
		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,	Variance [4]
		a	b	c	d	e = 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)	$ 921,223	$ 722,032	$ -	$ -	$ 199,191	5.00	20.00%	**$ 39,838**	$ 39,838	**$ -**
1612	Land Rights (Formally known as Account 1906)	$ 70,296	$ 54,296	$ -	$ -	$ 16,000	25.00	4.00%	**$ 640**	$ 640	**$ 0**
1805	Land	$ 155,686	$ -	$ -	$ -	$ 155,686	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 101,761	$ 12,061	$ -	$ -	$ 89,700	60.00	1.67%	**$ 1,495**	$ 1,495	**$ 0**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ 467,359	$ 41,944	$ -	$ -	$ 425,415	31.46	3.18%	**$ 13,523**	$ 13,523	**$ -**
1820	Distribution Station Equipment <50 kV	$ 5,629,316	$ 564,756	$ 360,000	$ -	$ 5,244,561	39.25	2.55%	**$ 133,622**	$ 133,622	**$ 0**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 17,849,106	$ 560,825	$ 931,387	$ -	$ 17,753,974	50.00	2.00%	**$ 355,079**	$ 355,079	**$ 0**
1835	Overhead Conductors & Devices	$ 16,825,366	$ 6,693,483	$ 362,194	$ -	$ 10,312,980	50.00	2.00%	**$ 206,260**	$ 206,260	**$ 0**
1840	Underground Conduit	$ 2,982,504	$ 63,448	$ 82,500	$ -	$ 2,960,306	50.00	2.00%	**$ 59,206**	$ 59,206	**-$ 0**
1845	Underground Conductors & Devices	$ 17,155,550	$ 6,438,106	$ 1,463,500	$ -	$ 11,449,195	30.00	3.33%	**$ 381,640**	$ 381,640	**$ -**
1850	Line Transformers	$ 12,179,011	$ 2,147,114	$ 1,060,036	$ -	$ 10,561,915	40.00	2.50%	**$ 264,048**	$ 264,048	**-$ 0**
1855	Services (Overhead & Underground)	$ 1,254,827	$ 47,371	$ 46,350	$ -	$ 1,230,630	40.00	2.50%	**$ 30,766**	$ 30,766	**-$ 0**
1860	Meters	$ 3,973,374	$ 2,131,066	$ 154,500	$ -	$ 1,919,558	14.75	6.78%	**$ 130,162**	$ 130,162	**$ 0**
1860	Meters (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ 3,617,315	$ 14,545	$ 125,000	$ -	$ 3,665,270	31.75	3.15%	**$ 115,442**	$ 115,442	**$ -**
1910	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 38,163	$ 18,163	$ 50,000	$ -	$ 45,000	10.00	10.00%	**$ 4,500**	$ 4,500	**$ -**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 347,299	$ 252,585	$ 140,000	$ -	$ 164,714	4.00	25.00%	**$ 41,179**	$ 41,179	**$ -**
1930	Transportation Equipment	$ 2,791,693	$ 330,596	$ 661,436	$ -	$ 2,791,815	13.71	7.29%	**$ 203,597**	$ 203,597	**$ -**
1935	Stores Equipment	$ 30,023	$ 30,023	$ -	$ -	$ 0	10.00	10.00%	**$ 0**	$ -	**-$ 0**
1940	Tools, Shop & Garage Equipment	$ 184,630	$ 81,173	$ 10,609	$ -	$ 108,762	10.00	10.00%	**$ 10,876**	$ 10,876	**$ 0**
1945	Measurement & Testing Equipment	$ 67,087	$ 31,284	$ 100,000	$ -	$ 85,802	10.00	10.00%	**$ 8,580**	$ 8,580	**-$ 0**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 368,173	$ 257,454	$ -	$ -	$ 110,718	10.00	10.00%	**$ 11,072**	$ 11,072	**-$ 0**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ 315,235	$ 37,040	$ -	$ -	$ 278,196	25.00	4.00%	**$ 11,128**	$ 11,128	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ 1,904,563	$ 705,410	$ 242,050	$ -	$ 1,320,178	18.00	5.56%	**$ 73,343**	$ 73,343	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -		$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 6,746,872	$ 949,601	-$ 974,149	$ -	-$ 8,183,548	40.00	2.50%	**-$ 204,589**	-$ 204,589	**$ -**
2005	Property Under Finance Lease	$ -		$ -	$ -	$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 82,482,690**	**$ 22,184,376**	**$ 4,815,413**	**$ -**	**$ 62,706,020**	**$ 618**		**$ 1,891,407**	**$ 1,891,407**	**$ 0**

Appendix 2-E
Distribution System Plan

Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

Distribution System Plan

2025 Cost of Service Application

Historical Period:
2017 – 2024 (2024 Bridge Year)

Forecast Period:
2025-2029

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List of Acronyms

Acronym	Meaning
ACA	Asset Condition Assessment
ACSR	Aluminum Conductor Steel Reinforced
AEUSP	Association of Electrical Utility Safety Professionals
AM	Asset Management
AMI	Advanced Metering Infrastructure
AWG	American Wire Gauge
CDM	Conservation Demand Management
CHI	Customer Hour Interrupted
CI	Customer Interrupted
C&I	Commercial and Industrial
CNP	Canadian Niagara Power
COS	Cost of Service
DCA	Distribution
DER	Distributed Energy Resource
DR	Demand Reduction
DSC	Distribution System Code
DSO	Distribution System Operator
DSP	Distribution System Plan
EDA	Electricity Distributors Association
EOL	End of Life
ESA	Electrical Safety Authority
GIS	Geographic Information System
GS	General Service
GSC	Grid Smart City Cooperative
HI	Health Index
HONI	Hydro One Networks Inc.
ICM	Incremental Capital Module
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
LOS	Loss of Supply
LTR	Limited Time Rating
MED	Major Event Day
MIST	Meter Inside the Settlement Timeframe
NA	Needs Assessment
NPEI	Niagara Peninsula Energy Inc.
NWS	Non-Wires Solutions
OEB	Ontario Energy Board
OH	Overhead
REG	Renewable Energy Generation
RIP	Regional Infrastructure Plan
RRFE	Renewed Regulatory Framework for Electricity Distributors
RRR	Reporting and Record-keeping Requirements
SA	Scoping Assessment
SAIDI	Systems Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TUL	Typical Useful Life
UG	Underground
USF	Utilities Standards Forum
WHESC	Welland Hydro Electric System Corp.

5.2 Distribution System Plan

5.2.1 Distribution System Plan Overview

Welland Hydro-Electric System Corp. ("WHESC") has prepared this Distribution System Plan ("DSP") in accordance with the Ontario Energy Board's ("OEB's") Chapter 5 Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications ("the Filing Requirements") as part of its 2025 Cost of Service Application (the "Application").

This DSP is a stand-alone document that is filed in support of WHESC's Application. This document has been organized using the same headings as the Filing Requirements, with the corresponding section number from the Filing Requirements for each heading. It identifies material initiatives and programs to be undertaken during the filed planning period. The DSP spans 13 years, with the historical period of 2017 to 2024, with 2024 being the bridge year, and a forecast period of 2025 to 2029, with 2025 being the test year.

The DSP contents are organized into three major sections including:

- Section 5.2 provides an overview of the DSP, including coordinated planning with Third Parties, and performance measurement for continuous improvement.
- Sections 5.3 provides an overview of WHESC's Asset Management ("AM") practices, includes asset lifecycle optimization, and capacity for renewable energy generation ("REG").
- Section 5.4 provides a summary of WHESC's capital expenditure plan, including an overview of the capital expenditure planning process, and justification of the material projects (above the material threshold of $68,000).

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

5.2.1.1 Description of the Utility Company

WHESC is a municipally owned electricity distributor, wholly owned by the City of Welland, licensed by the OEB. In accordance with its Distribution License ED-2003-0002, WHESC provides electricity distribution services within the City of Welland.

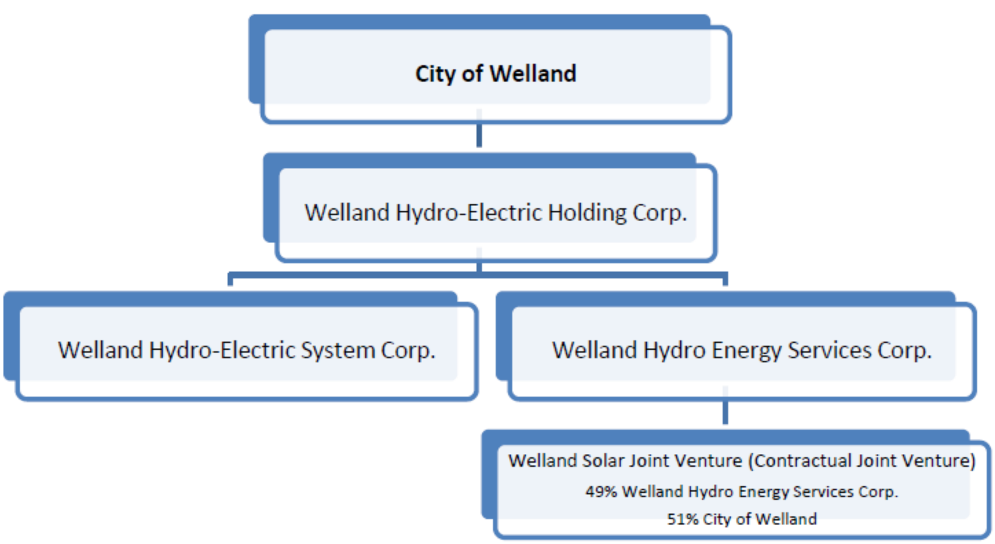


Figure 5.2-1: Corporate Structure

WHESC supplies service to 25,753 customers in a service territory of approximately 81 square kilometers. Additional details regarding WHESC's service area are provided in Section 5.3.2.1. Figure 5.2-2 illustrates WHESC's service territory boundaries.

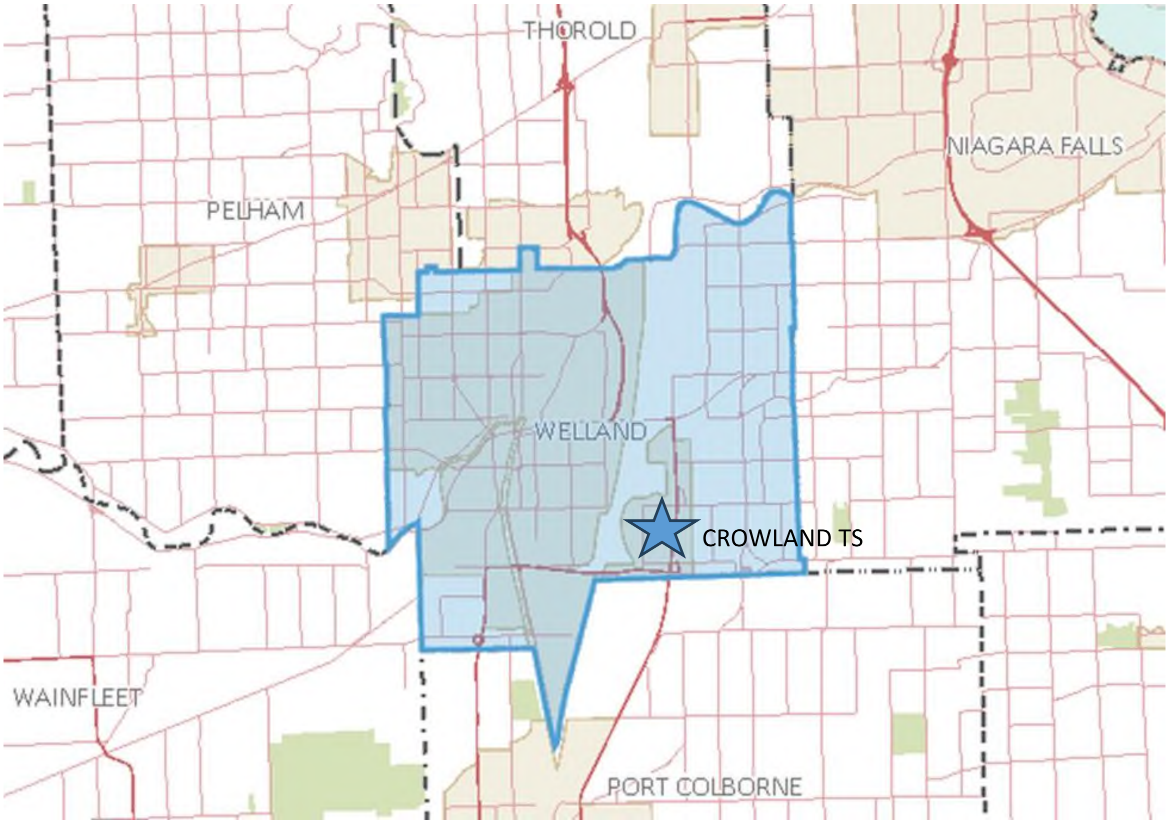


Figure 5.2-2: Map Depicting WHESC's Service Area Boundaries

WHESC strives to work collaboratively amongst utility professionals through membership with the Electricity Distributors Associated ("EDA"), Utility Standards Form ("USF"), Association of Electrical Utility Safety Professionals ("AEUSP") and the Grid Smart City Cooperative ("GSC").

WHESC owns, maintains, and operates approximately 498 km of overhead primary distribution feeders and 161 km of underground primary distribution circuits. WHESC receives power from a single transformer station ("Crowland TS"), which is owned and operated by Hydro One Networks Inc. ("HONI"). The station provides nine 27.6kV feeder breakers to distribute power throughout the city via WHESC's 27.6 kV distribution system.

Our Vision

Welland Hydro will remain a community-owned asset and continue to collaborate with others, embracing best practices to implement appropriate product and service innovations in a timely manner within an ever-changing provincial policy environment.

Our Mission

Welland Hydro is a community-owned asset whose team of highly skilled professionals are committed to distributing safe, reliable power that enhances the quality of life in Welland.

This DSP was prepared to provide to the OEB and all interested stakeholders:

- An overview of WHESC's asset planning objectives and goals;
- A review of WHESC's asset-related operational performance in the eight-year historical period;
- A preview of WHESC's planned expenditures for the forecast period that illustrates WHESC's plan for further-improving its asset-related performance against the four outcomes established by the OEB; and
- A detailed justification of WHESC's planned capital expenditures in the 2025 Test Year.

5.2.1.2 Capital Investment Highlights

In the Filing Requirements, the OEB has specified the investment categories to be used by distributors in their filings. WHESC has identified each investment category and the key drivers that are applicable in each case. These are listed at a program category level along with a representative example of the applicable projects/activities presented in this DSP based on the 'trigger' driver of the expenditure. The result of this is summarized in Table 5.2-1 below. Each program category has been expanded in greater detail in subsequent sections of the DSP that describe specific projects within each.

	OEB Example Drivers	OEB Example Projects/Activities	WHESC Drivers	WHESC Program Categories
System Access	Customer Service Request	New customer connections. Modifications to existing customer connections. Expansion for customer connections or property developments.	Customer Service Requests	Customer Connections Expansions (Subdivisions) Expansions (Transformers/Meters)
	Other 3rd party infrastructure development requirements	System modifications for property or infrastructure development (e.g. relocating pole lines for road widening).	Other 3rd party infrastructure development requirements	Municipal Relocations
	Mandated Service Obligations (Distribution System Code, Conditions of Service, etc.	Metering. Long Term Load Transfer.	Mandated Service Obligations	Retail Meters
System Renewal	Assets/asset systems at end of service life due to: -failure -failure risk -substandard performance -high performance risk -functional -obsolescence	Programs to refurbish/replace assets or asset systems; (e.g.. poles, conductor, physical plant, relays, switchgear, transformer, other equipment).	Assets/asset systems at end of service life due to failure or failure risk. Distribution loss reduction. SAIDI/SAIFI.	Substation Renewal Overhead Line Renewal Underground Line Renewal Miscellaneous
System Service	System operations objectives -Safety -Reliability -Power Quality -Other performance/functionality	Protection & control upgrade; (e.g. reclosers, relays). Automation by device type/function. SCADA.	System operations objectives: Safety Reliability Power Quality Other performance/ functionality SAIDI/SAIFI	SCADA Enhancements Substation System Enhancements
General Plant	System capital investment support System maintenance support Business operations efficiency Non-system physical support	Structures & depreciable improvements. Equipment and tools. Finance & Admin/Billing Software Systems.	System capital investment support System maintenance support Business operations efficiency Non-system physical support	Furniture & Equipment Computer Hardware Computer Software Communication Equipment Measurement & Testing Equipment Tools Automotive Equipment & Vehicles Buildings & Grounds Renewables

Table 5.2-1: Summary of WHESC's Investment Drivers

Historical capital investments in each of these categories have been provided in Table 5.2-2, along with forecast capital expenditures. Capital contributions in support of system expansions are shown in this table along with the system operating and maintenance expenditures in each year.

CATEGORY	Historical Period							Bridge	Forecast				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
System Access	76	424	474	1,548	1,043	1,063	2,143	2,329	1,577	1,624	1,672	1,724	1,775
System Renewal	1,788	1,418	1,936	2,272	2,246	2,614	2,328	2,405	2,884	3,117	2,795	3,242	3,315
System Service	29	113	103	79	267	313	141	160	242	499	482	364	272
General Plant	358	563	1,201	314	455	122	278	535	955	498	581	226	271
Gross Capital Expenditure	2,251	2,517	3,714	4,213	4,012	4,112	4,891	5,429	5,658	5,738	5,530	5,556	5,633
Capital Contributions	- 38	- 171	- 342	- 1,122	- 712	- 637	- 1,219	- 1,720	- 974	- 1,004	- 1,034	- 1,065	- 1,097
Net Capital Expenditure	2,212	2,347	3,372	3,091	3,300	3,475	3,671	3,709	4,683	4,734	4,496	4,491	4,536
System O&M	$ 3,379	$ 3,398	$ 3,601	$ 3,520	$ 3,662	$ 3,767	$ 3,826	$ 4,175	$ 4,705	$ 4,889	$ 5,063	$ 5,182	$ 5,336

Table 5.2-2: Historical Actual & Forecast Capex and OM&A

This DSP builds upon the previous version developed as part of the 2017 distribution rate application. In 2018, WHESC completed an Asset Condition Assessment ("ACA") to better inform investment decisions, particularly in the system renewal category. The ACA was updated in 2023, supporting asset management strategies in this DSP.

The latest ACA demonstrates improvements in a few key areas related to asset management over the historical period. The number of asset classes being monitored and assessed for health indices has increased from eight to fifteen. The data availability index has improved across all previously assessed asset classes. Additionally, the improvement in health index across the original eight asset classes demonstrates a commitment sustaining the performance of WHESC's distribution system.

WHESC monitors reliability performance, asset health indices, asset utilization, and customer connection requirements as key drivers for capital expenditure planning. WHESC's objective in this DSP is to appropriately prioritize and pace non-discretionary capital investments related to replacement or renewal of assets at end-of-life.

The investment drivers over the forecast period are as follows:

System Access

System Access investments are modifications to the existing system that will allow WHESC to provide customers with access to its electricity services. These investments are often triggered by customer requests and are completed to fulfill WHESC's service obligations. Forecasted expenditures are based on load growth estimates. WHESC regularly participates in pre-consultation activities with the municipality and gleans information on prospective development activity. The City of Welland has experienced an uptick in housing and commercial development since 2019, resulting in increased expenditure in this category of investment. New development has triggered road relocation work and system expansions to facilitate new connections.

Meter reverification work, new customer connections and commercial Meter Inside the Settlement Timeframe (MIST) installations will continue into the forecast period. Meter pre-sampling and final sampling for meter seal extensions are expected to have a minor additional cost impact in the years 2025 through 2029.

System Renewal

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

As seen in Table 5.2-2 above, System Renewal represents approximately 67% of the forecasted net capital expenditures based on the asset replacement requirements over the period. Both overhead and underground system rebuilds offer the opportunity in many areas to incorporate voltage conversions, during the design and construction stages, resulting in reduced system losses. The pacing of asset replacement in the forecast period is expected to remain consistent with the historical period, giving due consideration to customer engagement results informing this DSP.

System Service

System Service investments include the deployment of new assets aimed at improving reliability and distribution system redundancy. With increased growth and expansion of the distribution system, WHESC continues to deploy distribution system automation to sustain or improve reliability. Historically, WHESC invested in Supervisory Control and Data Acquisition ("SCADA") systems and protection system upgrades to improve grid visibility. Planned capital investments in the forecast period aim to continue the deployment of monitoring and control devices to improve flexibility and resiliency.

Additional investments in this category have been planned to add external intertie capability, enabling load transfers. These investments will bridge the capacity gap identified in Integrated Regional Resource Planning (IRRP) pertaining to the Welland area.

General Plant

General Plant investments are performed to maintain assets that are not part of the distribution system but are used to support day-to-day business and operational activities. The average annual expenditure in this investment category over the forecast period is approximately 11% of the total budget. The main expenditures in this category during the Test Year and over the forecast period are with respect to fleet sustainment, facility upgrades, and re-investment in information systems.

5.2.1.3 Key Changes since Last DSP Filing

COVID-19 Pandemic

The COVID-19 pandemic led to additional challenges that will likely persist over the DSP period of 2025 to 2029. WHESC has experienced significant increases in material and equipment costs, a strained labor market and supply chain disruptions that have affected project execution. WHESC has considered these factors when planning and has taken steps to ensure these challenges are considered in advance of program execution.

Climate Change

In 2023, the OEB released a Report to the Minister of Energy titled "Improving Distribution Sector Resilience, Responsiveness, and Cost Efficiency". The report was in response to the Minister's Letter of Direction in 2022, requesting advice and proposals from the OEB to improve distribution sector resiliency, responsiveness and cost efficiency in relation to major weather events.

Major weather events impacting Ontario Local Distribution Companies ("LDC"s) have increased in frequency in recent years as the impacts of climate change intensify. The items proposed in the report that WHESC has focused on in relation to the DSP are:

- Integrating resilience into system planning
- Engaging in regular data-driven assessments of vulnerabilities in the distribution system and operations in the event of server weather
- Prioritizing value for customers when investing in system enhancement for resilience purposes
- Measuring and reporting on restoration of service metrics

WHESC plans to continue investment in grid modernization with technology deployments that benefit grid visibility. To maximize the benefit of technology deployments, WHESC has implemented a 24 x 7 system control operation. This allows WHESC to operationally position itself to manage high impact events. The system control operation has been implemented using a shared cost model with another LDC in alignment with the same resiliency and grid visibility objectives. WHESC believes that this, along with its asset management based decisions prioritize the value for customers in improving resiliency posture. Customer engagement in support of this application confirmed that there is a desire to ready our distribution system in advance of significant weather events.

Energy Transition / Electrification

The energy transition of transportation and heating sources is at the forefront of planning processes. WHESC in partnership with GSC member LDCs, procured an Electrification Strategy Study. This study provides insight on potential EV adoption rates and heating fuel source switching, along with recommendations on system preparedness. WHESC considered these recommendations in developing its capital investment plan over the forecast period.

WHESC uses its SmartMap system as a tool to identify portions of its distribution system where Level 2 or higher EV charging is deployed. This tool is also used to identify impacts of EV related load additions to the distribution system, informing planning decisions. WHESC will continue to monitor data analytic tools along with changing customer requirements to inform investment decisions and capacity requirements.

Asset Condition Assessments

WHESC's previous DSP was not supported by an ACA when filed with the 2017 Cost of Service (COS). WHESC performed an ACA in 2018 and the resulting report was used to better inform system renewal investments in the historical period. In 2023, WHESC updated the ACA, and the associated report is a significant driver of planned system renewal investments in the forecast period.

Acceleration of Residential Housing Development

The City of Welland became increasingly proactive in economic development initiatives aimed at increasing housing starts during the historical period. With recent participation by the municipality in the Ontario Government's Building Faster Fund, it is likely that recently experienced residential growth rates will continue. This will continue to have an impact on the level of system access investment required to facilitate new electricity connections.

5.2.1.4 DSP Objectives

WHESC's DSP is designed to support the achievement of the four key OEB established Renewed Regulatory Framework for Electricity (RRFE) 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; utilities deliver on system reliability and quality objectives;

3. **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirement imposed further to Ministerial directives to the Board); and

4. **Financial Performance**: financial viability is maintained; and savings from operational effectiveness are sustainable.

The majority of WHESC's planned investments are categorized as system renewal (over 65%). While asset renewal investments are paced, a fundamental objective is to sustain system reliability by maintaining a prudent level of asset health. From recurring bi-annual surveys and most recently, feedback received on WHESC's DSP, system reliability ranks in the top two customer concerns, along with affordability. WHESC's current DSP incorporates a sufficient level of renewal and system service based investment to sustain reliability performance while managing growth.

System service investment accounts for approximately 8% of WHESC's planned capital expenditure. Most of the planned investment in this category is directed at continued grid modernization initiatives. With growth in customer connections and planned conversion of existing load to the 27.6 kV system, WHESC continues to manage increased exposure on its nine distribution circuits. Continued improvement in system reliability is achieved through the deployment of automated recloser, sectionalizer, and switching devices. These deployments expedite restoration activities via SCADA through WHESC's system control service, available on a 24 x 7 basis.

While planned system service based investment benefits system reliability, grid visibility is also enhanced. This positions WHESC's distribution system to manage increased connections related to electrification and DER deployment. WHESC continues to integrate real time data stemming from these investments into its analytical tools, namely SmartMap. This enables near real time analysis of power flow and asset utilization to make prudent operational and asset management decisions.

WHESC exercised cost control through its previous DSP period, resulting in the assignment of Cohort 1 to the LDC in 2021. The Cohort assignment is a result of OEB benchmarking activities used for establishing stretch factor rankings. WHESC intends to continue employing cost control measures aimed at balancing affordability with performance. WHESC understands that the Minister of Energy continues to be focused on affordability, observing key themes from the letter of direction provided to the OEB in October of 2022. In the context of "Distribution Sector Resiliency, Responsiveness, and Cost Efficiency", the letter indicated:

> *"Ontario's electricity distribution sector will have a critical role in Ontario's electrification transition. As the pace of the electrification of the economy increases and extreme weather events as a result of climate change impact our businesses and communities, there will be pressure on local distribution companies (LDCs) to continue to provide high levels of reliability and resiliency to their customers, be responsive to changing consumer expectations and new government mandates, and to do it all at an affordable price. This year, Ontario experienced two extreme weather events, which affected LDC infrastructure across Eastern Ontario. As our climate changes, the OEB will have an important role to play in ensuring LDCs are preparing their distribution infrastructure for these kinds of events. LDCs will need greater capacity to meet these expectations – capacity that can be enabled by aggressively pursuing efficiencies through consolidation or enhanced shared services, adoption of innovative technologies and processes, collaboration on responsibilities like cybersecurity, and changes to the utility remuneration and incentive structure that ensure LDCs make the right investments for their customers."*

This DSP demonstrates a continued effort to pursue efficiencies through shared service approaches while improving system resiliency. WHESC collaborates with GSC partner LDCs to implement best practices when deploying grid automation based technology, deploying common standards and operating philosophies to maximize efficiency. WHESC has implemented a shared system control service designed to maximize the benefits of these technology deployments at a shared cost. WHESC intends to continue this approach in preparation for intensification of electrification activities and increased EV adoption rates. WHESC will be well positioned to manage increased penetration of DER and ready for the requirements of a Distribution System Operator (DSO), as this evolves.

WHESC must keep pace with new connection requirements and as such has planned approximately 14% of net capital investment in the system access category. With accelerated housing development evident in the historical period, WHESC leverages information gleaned from routine participation in municipal planning activities to determine the expected level of expenditure required for System Access based investments.

Investments in General Plant are largely aimed at asset renewal expenditures. WHESC has completed needs assessments of fleet, facilities, and information systems to determine the necessary level of investment required to sustain function. General Plant based investments account for 11% of WHESC's planned capital expenditure.

5.2.2 Coordinated Planning with Third Parties

5.2.2.1 Customers

WHESC understands the importance of coordinating infrastructure planning with the customers it serves. In support of this DSP, WHESC internally designed and implemented a customized customer engagement strategy. The purpose of the engagement was to:

- Educate customers on our role as a distributor
- Provide an understanding of WHESC's cost profile
- Gain information on how customers foresee changes in their electricity usage
- Provide an overview of our investment plan
- Obtain customer feedback regarding the appropriateness the investment plan
- Confirm preferences for future engagement

WHESC created a survey workbook which can be found in Appendix 5-C. The survey was deployed via the internet, using the Constant Contact platform. The platform allowed WHESC to gather survey results in a secure and anonymized manner.

WHESC reached out to 7,459 residential and general service customers that have e-mail contact information on file. The survey was also advertised on WHESC's website and social media platforms. Survey responses were gathered in May of 2024.

There were 988 survey respondents, consisting of 973 residential, 11 GS < 50 kW, and two GS > 50 kW customers. Two respondents completed the survey that are not customers of WHESC. Figure 5.2-3 summarizes the survey responses regarding the type of electricity customer participating.

MULTIPLE CHOICE

What type of electricity customer are you?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Residential		973	98%
Small Business (described on your bill as account type GS < 50)		11	1%
Commercial/Industrial (described on your bill as account type GS > 50)		2	0%
I'm not a Welland Hydro customer		2	0%
	Total Responses	988	100%

Figure 5.2-3: Customer Engagement: Type of Electricity Customer

Most respondents indicated that they are satisfied with the service level provided by WHESC. This is in alignment with feedback received from bi-annual customer satisfaction surveys. Most recently WHESC's customer satisfaction rating from the bi-annual survey was 98%. In addition, as evident in previous surveys, customers indicated that affordability and service reliability are the most important factors for us to consider. WHESC's strategic goals and objectives continue to align with this feedback.

WHESC has reviewed the balance of customer feedback gleaned from this engagement and has considered the following to inform planned expenditures:

- Customers indicated that electricity usage would likely continue to be the same with only 18% of respondents indicating anticipation of increase usage
- WHESC should prepare for extreme weather events, influenced by climate change, to the greatest extent possible
- Customers believe technology enhancements are important to access outage information and monitor usage
- Operating expenses are appropriate, however affordability is a top priority
- System renewal activities should be accelerated with over 50% of respondents supporting that approach
- Grid modernization investments should be accelerated

This DSP and, specifically, planned investment levels have incorporated this customer feedback. Following a description of WHESC's categoric investment plan for the forecast period, specific questions were asked to assess whether customers were supportive of the plan.

For overhead line rebuilds, customers were asked the question depicted in Figure 5.2-4.

Overhead Line Rebuilds

The majority of Welland Hydro's distribution system consists of overhead lines. Approximately $7.3M of investment is planned to rebuild sections of the overhead system. This includes the replacement of approximately 550 poles, 120 transformers, and 24km of deficient conductor. For reference, Welland Hydro's recent Asset Condition assessment indicates that 591 poles are in "Very Poor" condition.

12) Given the details provided about planned overhead line rebuilds in the next five years, should Welland Hydro:

- ☐ Proceed with the current plan, replacing 550 poles in "Very Poor" condition.
- ☐ Proceed at an accelerated pace, replacing 750 poles, including poles in both "Very Poor", and "Poor" condition. For a residential customer, this would result in a bill increase of $0.04 per month annually ($0.48 more per year).
- ☐ Proceed at a slower pace, replacing only 300 poles in "Very Poor" condition. For a residential customer, this would result in a bill decrease of $0.03 per month annually ($0.36 less per year).

Figure 5.2-4: Customer Engagement - Overhead Line Rebuilds

The response result to the question pertaining to overhead line rebuilds is summarized in Figure 5.2-5. Over 50% of WHESC customers indicated that WHESC should proceed with overhead line rebuilds at an accelerated pace, given the advertised bill impact to a residential customer.

MULTIPLE CHOICE

Given the details provided about planned overhead line rebuilds in the next five years, should Welland Hydro:

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Proceed with the current plan, replacing 550 poles in "Very Poor" condition.		352	35%
Proceed at an accelerated pace, replacing 750 poles, including poles in both "Very Poor", and "Poor" condition. For a residential customer, this would result in a bill increase of $0.04 per month annually ($0.48 more per year).		560	56%
Proceed at a slower pace, replacing only 300 poles in "Very Poor" condition. For a residential customer, this would result in a bill decrease of $0.03 per month annually ($0.36 less per year).		76	7%
	Total Responses	**988**	**100%**

Figure 5.2-5: Customer Engagement - OH Line Response

Pertaining to underground system replacements, customers were asked:

Underground System Replacements

Welland Hydro maintains approximately 160km of underground distribution systems. Approximately $5.1M of investment is planned to rebuild sections of the underground system. This includes the replacement of approximately 4km of deficient cable, 60 transformers, and 5 switching cubicles. For reference, Welland Hydro's recent Asset Condition assessment indicates that 3.7km of underground cable is in "Poor" or "Very Poor" condition, with 11km being over 40 years in service.

13) Given the details provided about planned underground system replacements in the next five years, should Welland Hydro:

- ☐ Proceed with the current plan, replacing 4km of cable and associated systems over 40 years in service.
- ☐ Proceed at an accelerated pace, replacing 6km of cable and associated systems over 40 years in service. For a residential consumer, this would result in a bill increase of $0.02 per month annually ($0.24 more per year).
- ☐ Proceed at a slower pace, replacing 3.2 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).

Figure 5.2-6: Customer Engagement - Underground System Replacements

The response result pertaining to underground system replacements is summarized in Figure 5.2-7. Over 50% of WHESC customers indicated that WHESC should proceed with underground system replacements at an accelerated pace, given the advertised bill impact to a residential customer.

MULTIPLE CHOICE

Given the details provided about planned underground system replacements in the next five years, should Welland Hydro:

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Proceed with the current plan, replacing 4 km of cable and associated systems over 40 years in service.			380	38%
Proceed at an accelerated pace, replacing 6 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill increase of $0.02 per month annually ($0.24 more per year).			532	53%
Proceed at a slower pace, replacing 3.2 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).			76	7%
		Total Responses	**988**	**100%**

Figure 5.2-7: Customer Engagement - UG System Response

Pertaining to grid modernization investments, customers were asked:

Grid Modernization Investments

Welland Hydro maintains a fleet of 34 automated devices on its main distribution system. These devices are designed to detect system anomalies and operate to isolate faulted sections of circuit. Welland Hydro's system control staff leverages these devices to minimize the number of customers impacted by an outage and in many cases, mitigate the total duration of the event. The five-year investment plan includes $875K for the deployment of 10 additional automated devices to maintain or improve reliability as the distribution system expands to accommodate growth.

14) Based on the grid modernization investments planned for the next five years, should Welland Hydro:

- ☐ Proceed with the current plan, introducing two new automated devices per year.
- ☐ Proceed at an accelerated pace, introducing three new automated devices per year. For a residential consumer, this would result in a bill increase of $0.01 per month annually ($0.12 more per year).
- ☐ Proceed at a slower pace, introducing one new automated device per year. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).

Figure 5.2-8: Customer Engagement - Grid Modernization Investments

The response result pertaining to grid modernization investments is summarized in Figure 5.2-9. Over 50% of WHESC customers indicated that WHESC should proceed with grid modernization investments at an accelerated pace, given the advertised bill impact to a residential customer.

MULTIPLE CHOICE

Based on the grid modernization investments planned for the next five years, should Welland Hydro:

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Proceed with the current plan, introducing two new automated devices per year.		390	39%
Proceed at an accelerated pace, introducing three new automated devices per year. For a residential customer, this would result in a bill increase of $0.01 per month annually ($0.12 more per year).		507	51%
Proceed at a slower pace, introducing one new automated device per year. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).		91	9%
	Total Responses	**988**	**100%**

Figure 5.2-9: Customer Engagement - Grid Modernization Response

Where feasible, adjustments have been made to capital expenditure levels incorporating feedback related to discretionary investments. This includes system renewal investment pacing and expenditures in the system service category.

Complete survey results are included in Appendix 5-D.

5.2.2.2 Large Customers

WHESC communicates annually with large customers having over 1MW of average monthly peak demand. The purpose is generally to discuss power quality, reliability and redundancy issues. Future capacity requirements and any participation in demand response or conservation activities are discussed on an annual basis to assist customers in managing electricity utilization. This also assists WHESC in understanding how utilization changes impact the operation of the distribution system and investment plans.

5.2.2.3 Subdivision Developers

WHESC recognizes that subdivision development is a part of a larger provincial and national objective, having greater focus in the current landscape. Well planned subdivision development processes provide connection efficiency and can reduce execution time.

WHESC has regular interaction with subdivision developers in cooperation with municipal and regional planning stakeholders. Typically, the City of Welland initiates development consultations, inviting relevant stakeholders in the area.

At the time of writing this DSP, there are 943 pending connections based on committed residential subdivision developments. From municipally driven consultation meetings, WHESC is also aware of pending developments that have not yet reached the point of contractual arrangements. In addition, there is a queue of approximately 10 commercial developments in various stages of design and construction and some system expansions to meet development needs. Development projects are funded under the System Access category.

5.2.2.4 Municipalities

WHESC takes part in the "South Niagara Public Utilities Committee" which meets quarterly. As of this writing, the most recent meeting was in November 2023, and attendees included Municipal and

Regional Representatives from across the area as well as Ministry of Labour, Ministry of Transportation, Enbridge Gas, and Niagara Peninsula Conservation Authority in addition to the other LDCs and telecommunication entities as discussed below.

At this meeting, the City of Welland presented plans for infrastructure renewal and expansions that may have impacts on WHESC plant under the System Access category. In addition, the Niagara Region has about 15 projects in the Welland area that may require coordination with WHESC plant under the System Access category.

Also at these recurring committee meetings, WHESC presents the status of System Renewal projects that require coordination with the other utilities in the area.

5.2.2.5 Transmitter

WHESC took part in the Niagara Regional Infrastructure Plan (RIP) report as published by HONI in July 2023. The report is attached in Appendix 5-E. The RIP follows the completion of the Niagara Integrated Regional Resource Plan (IRRP), and the Niagara Region Needs Assessment (NA) and Scoping Assessment (SA) plans completed since 2021.

The RIP identifies a 2.3% annual load growth across the entire area from 2023 to 2032 which includes large industrial customers. The projected growth rate for LDCs not accounting for industrial customers is 1.3%/yr.

The RIP identifies several needs in the WHESC supply system. The transformers at Crowland TS (WHESC's only supply point), will exceed their 10-day Limited Time Rating (LTR) in 2024 and there is a need to perform asset renewal on the transformers by 2029. There is also a need to upgrade capacity of the 115 kV supply lines A6C/A7C between Crowland TS and Allanburg TS by 2029. This is to reduce load on the Allanburg 230 kV to 115 kV autotransformers. In addition, the RIP notes that loss of the incoming 230 kV circuits Q26M/Q28A will result in an unacceptable load loss on the A6C/A7C circuits supplying WHESC and Port Colborne and will require mitigation.

To resolve these constraints, HONI is proposing to increase the supply voltage to Crowland TS from 115 kV to 230 kV and the capacity from 50/83 MVA to 75/125 MVA. Included in that project, HONI will upgrade the 18 km of double circuit line from Crowland TS to "Abitibi Junction" from 115 kV to 230 kV. (See Figure 5.2-10)

A separate project will upgrade the 230 kV circuit (Q28A) from "Abitibi Junction" to the Beck 2 SS which is expected to exceed its line rating in 2024. The 115 kV A6C circuit from Crowland south to Port Colborne TS was replaced in the previous planning cycle and will remain.

As per the RIP, HONI is estimating an investment of $128 Million for the Crowland 230 kV conversation and an additional $3 Million for the Q28A 230 kV line uprate. The Crowland TS project has a planned In-Service date of 2029.

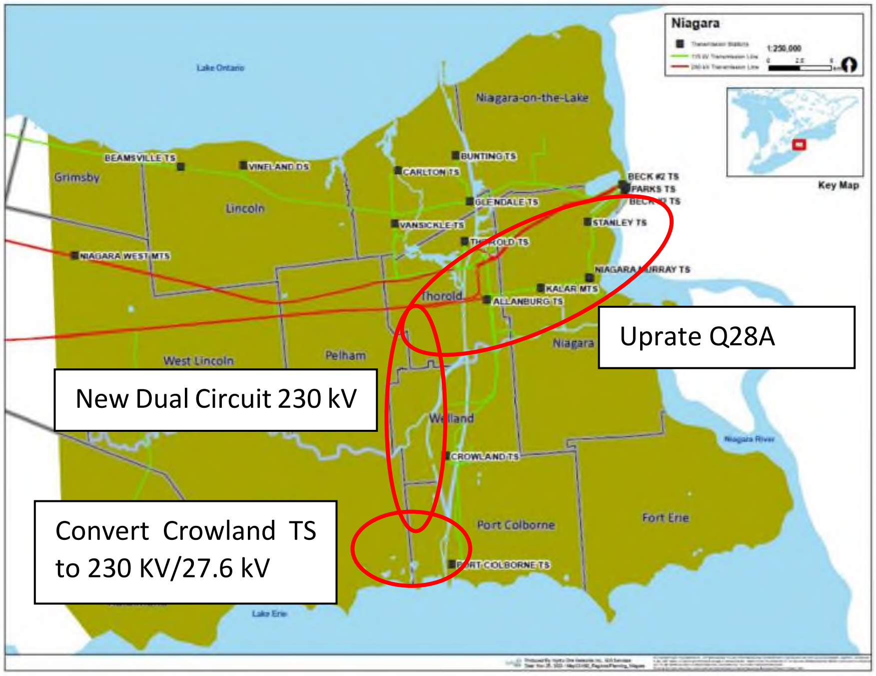


Figure 5.2-10: Regional Infrastructure Planning for the Crowland TS Replacement

5.2.2.6 Other LDC's

Regional LDCs took part in the RIP process detailed in Section 5.2.2.5, above. The complete list being Alectra Utilities Corporation, Canadian Niagara Power Inc., Grimsby Power Inc., HONI-Distribution, Niagara-on-the-Lake Hydro Inc., Niagara Peninsula Energy Inc and WHESC. There are several projects listed in the RIP that affect supply constraints to those service territories. It is reasonably concluded that WHESC has coordinated supply options with the neighbouring LDC's.

5.2.2.7 IESO

The Niagara IRRP was completed by the IESO in December 2022. The IESO was also party to the RIP discussed in detail in Section 5.2.2.55.1Transmitter. The IRRP was stakeholder-ed following the IESO standard procedures.

5.2.2.8 Regional Planning Process

The regional planning process includes the RIP discussed in Section 5.2.2.5, and the IRRP that was completed by the IESO in 2022. The IRRP supports the load growth estimates for Crowland TS that indicate the facility will be beyond capacity in the near term (immediately). The IRRP also makes the conclusion that the 115 kV network in the area is over capacity effective immediately. Thirdly the IRRP supports the need to replace the aged transformer assets at Crowland TS as soon as 2026. Finally, the IRRP concludes that load security on the WHESC 115 kV supply feeders requires intervention.

As part of the solution for the WHESC, non-wires alternatives were explored. These included Conservation Demand Management (CDM), Distributed Energy Resources (DER), and Demand Reductions (DR). All were reviewed and rejected. In addition, the process identified that the overload condition at Crowland TS would persist even if the station were renewed (like for like) and therefore an upgrade of capacity at Crowland TS is required, and it should be transferred to a 230 kV supply as the preferred solution.

There are no inconsistencies between this DSP and the current Regional Plan. The preferred solution to address WHESC needs as described above, will likely result in capital investment requirements for the station capacity incremental and costs associated with new feeder egress. WHESC's cost obligations for these items are not currently known and will be identified through the detailed design and associated cost assessments produced by the transmitter. It is WHESC's intention to file an Incremental Capital Module ("ICM") related to these investment requirements, once specific obligations are known.

5.2.2.9 Telecommunication Entities

The telecommunications companies in WHESC's service area consisting of Cogeo, Bell Canada, Niagara Regional Broadband, and Rogers take part in the South Niagara Public Utilities Commission as described in Section 5.2.2.4. This occurs on a quarterly basis.

At the most recent meeting, Cogeco presented a list of 20 projects at various stages of design and construction in the Welland service area. In addition, the Niagara Region maintains a permitting system for on-going work on regional right-of-ways and provided a list of ten active permits in the Welland area. Approximately half of these are telecommunications projects.

As a result of these consultations, WHESC is well informed of the activities of the telecommunication entities in the area and has the opportunity to plan for any future requirements. WHESC is not currently planning any specific projects required to support telecommunications needs.

5.2.2.10 Renewable Energy Generation

Currently, WHESC has 18.2 MW of connected Renewable Energy Generation (REGs) and Distributed Energy Resources (DER) connected to the distribution system. There is an additional 6MW of applications in the queue. It is understood that all REG facilities connected to the system are DERs, but not all DERs are "renewable". Also, energy storage is a DER that can be renewable if paired with a renewable resource. For the purpose of system constraints all REG / DER connections need to be assessed, but for the purpose of REG investments, only the renewable resources are considered.

The WHESC system has a capacity in excess of the upstream HONI station capacity and is not significantly constrained for the addition of new REGs and/or DERs on any of its feeders. WHESC expects to be able to continue connecting projected REGs and DERs. There are no embedded distributors on the WHESC system that influence capacity to connect, however, there is a HONI owned and operated feeder (M13) at Crowland TS. The HONI owned M13 feeder does have REG/DER connections which consume some of the available capacity at Crowland TS.

Any generation connection will add to system short circuit levels that occur in the event of a fault. WHESC must assess REG/DERs for impact on short circuit levels associated with distribution circuits. HONI performs Distribution Connection Assessments ("DCA") to identify any impacts on the upstream supply systems, inclusive of Crowland TS.

Any generation on the system will affect the thermal limitations for normal operation of equipment. WHESC must assess REG/DERs for thermal impacts including directional flow at Crowland TS.

It is necessary to avoid system "islanding" in the event that the source protection operates as per the requirements of CSA 22.3 No 9 which is derived from IEEE 1547. There are various mechanisms to ensure "anti-islanding" depending on the size of the generator and the type of the resource.

The following is a summary of the REG and DER connections to the WHESC system since 2008:

Year	FIT		MicroFit		Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
2008	-	-	1	9.4	-	-	-	-	-	-	1	9.4
2009	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	1	10.0	-	-	-	-	-	-	1	10.0
2011	-	-	8	71.7	-	-	-	-	-	-	8	71.7
2012	2	350.0	12	100.7	-	-	-	-	-	-	14	450.7
2013	2	500.0	16	170.0	-	-	-	-	-	-	18	670.0
2014	3	11,000.0	11	109.3	1	1.2	-	-	-	-	15	11,110.5
2015	-	-	19	190.0	-	-	-	-	-	-	19	190.0
2016	-	-	14	140.0	-	-	-	-	-	-	14	140.0
2017	-	-	23	230.0	1	5.7	2	73.0	-	-	26	308.7
2018	3	1,300.0	3	30.0	-	-	-	-	-	-	6	1,330.0
2019	-	-	-	-	-	-	-	-	1	3,828.0	1	3,828.0
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	1	10.0	-	-	-	-	1	10.0
2022	-	-	-	-	2	49.7	-	-	-	-	2	49.7
2023	-	-	-	-	3	27.8	-	-	-	-	3	27.8
Total	**10**	**13,150.0**	**108**	**1,061.0**	**8**	**94.3**	**2**	**73.0**	**1**	**3,828.0**	**129**	**18,206.4**

Table 5.2-3: REG/DER Connections

All of the facilities associated with the data supplied in Table 5.2-3 are REG with the exception of one Load Displacement facility rated at 3.8 MW. The fuel source for this facility is natural gas.

WHESC has assessed the ability to connect REG and DER facilities and constraints are governed by the available thermal and short circuit capacity at the supplying Crowland TS. Table 5.2-4 summarizes the current capacity consumed by WHESC:

Station	Bus Name	Feeders	Voltage (kV)	SC Cap. (MVA)	Thermal Cap. (MW)	Existing DG (MW)
Crowland TS	QY	M14, M15, M16, M17, M18, M19, M20, M21, M22	27.6	177.6	67.6	18.2 (WHESC only)

Table 5.2-4: Summary of DG Capacity at Crowland TS

WHESC has forecasted REG/DER connections from 2024 through to 2029. The forecast is based on assumed net metering facility deployments with recent changes to O. Reg. 541/05: Net Metering. WHESC is also aware of two contemplated load displacement facilities which are incorporated into the forecast in Table 5.2-5:

Year	Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW
2024	4	20					4	20
2025	7	35			1	6,000	8	6,035
2026	9	45			1	3,000	10	3,045
2027	11	55					11	55
2028	13	65					13	65
2029	15	75					15	75
Total	**59**	**295**	**-**	**-**	**2**	**9,000**	**61**	**9,295**

Table 5.2-5: Projected REG/DER Growth

Based on the projections in Table 5.2-5, WHESC does not have any feeder level constraints that would prohibit connection of these facilities. The most constrained distribution circuit in WHESC's system has the capability of connecting 8MW of REG/DER in addition to the forecasted facilities identified above. The constraint on that specific feeder (Crowland M17) is due to the presence of existing DER facilities consuming over 11MW of thermal capacity on the circuit.

WHESC submitted a REG investment plan to the IESO and received a Letter of Comment in response from the IESO. The IESO confirmed that WHESC's information on REG connections is consistent with that of the IESO and that the Regional Planning Needs Assessment Report indicates that the Regional Planning Process for the Niagara region is complete and will be undertaken again when the next five-year planning cycle commences. WHESC's REG investment plan has been included as Appendix 5-F and the full letter of comment can be found in Appendix 5-G.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

WHESC uses a set of performance measures to continuously monitor and evaluate achievement with respect to the four performance outcomes established by the OEB, particularly in respect to the Electricity Distributors Scorecard. These measures allow WHESC to capture deviations in its performance year-over-year and provide a means for comparison to other Ontario LDCs.

A summary of these performance measures detailed in the scorecard are outlined in Table 5.2-6, below:

<table>
<tr><th>Performance Outcome</th><th>Performance Category</th><th colspan="2">Measures</th></tr>
<tr><td rowspan="6">Customer Focus</td><td rowspan="3">Service Quality</td><td colspan="2">New Residential/Small Business Services Connected On Time</td></tr>
<tr><td colspan="2">Scheduled Appointments Met On Time</td></tr>
<tr><td colspan="2">Telephone Calls Answered On Time</td></tr>
<tr><td rowspan="3">Customer Satisfaction</td><td colspan="2">First Contact Resolution</td></tr>
<tr><td colspan="2">Billing Accuracy</td></tr>
<tr><td colspan="2">Customer Satisfaction Survey Results</td></tr>
<tr><td rowspan="10">Operational Effectiveness</td><td rowspan="4">Safety</td><td colspan="2">Level of Public Awareness</td></tr>
<tr><td colspan="2">Level of Compliance with Ontario Regulation 22/04</td></tr>
<tr><td rowspan="2">Serious Electrical Incident Index</td><td>Number of General Public Incidents</td></tr>
<tr><td>Rate per 10, 100, 1000 km of Line</td></tr>
<tr><td rowspan="2">System Reliability</td><td colspan="2">SAIDI</td></tr>
<tr><td colspan="2">SAIFI</td></tr>
<tr><td>Asset Management</td><td colspan="2">Distribution System Plan Implementation Progress</td></tr>
<tr><td rowspan="3">Cost Control</td><td colspan="2">Efficiency Assessment</td></tr>
<tr><td colspan="2">Total Cost per Customer</td></tr>
<tr><td colspan="2">Total Cost per km</td></tr>
<tr><td rowspan="3">Financial Performance</td><td rowspan="3">Financial Ratios</td><td colspan="2">Liquidity: Current Ratio</td></tr>
<tr><td colspan="2">Leverage: Total Debt to Equity Ratio</td></tr>
<tr><td colspan="2">Profitability: Regulatory Return on Equity</td></tr>
</table>

Table 5.2-6: Performance Metrics - OEB's Electricity Distributor Scorecard

Welland Hydro also tracks distribution losses to monitor asset/system operations performance. This additional metric is shown in Table 5.2-7:

Performance Outcomes	Performance Categories	Measures	Motivation
Asset and/or System Operations Performance	Distribution Losses	Percentage Line Loss	Corporate

Table 5.2-7: Performance Metrics - Distribution Losses

The performance metrics as described above are addressed in the following sections. Table 5.2-8 summarizes WHESC's performance over the historical period:

Performance Outcome	Performance Category	Measures		2017	2018	2019	2020	2021	2022	2023
Customer Focus	Service Quality	New Residential/Small Business Services		100.00%	100.00%	94.82%	94.52%	99.68%	99.61%	95.53%
		Scheduled Appointments Met On Time		98.64%	94.90%	93.16%	98.28%	97.88%	93.99%	94.88%
		Telephone Calls Answered on Time		96.19%	97.29%	88.90%	86.15%	83.07%	77.88%	76.33%
	Customer Satisfaction	First Contact Resolution		75.00%	80.00%	80.00%	77.00%	99.89%	99.81%	99.70%
		Billing Accuracy		99.98%	99.99%	99.99%	99.99%	99.91%	99.88%	99.97%
		Customer Satisfaction Survey Result		92.00%	96.00%	96.00%	96.00%	96.00%	98.00%	98.00%
Operational Effectiveness	Safety	Level of Public Awareness		83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	C
		Serious Electrical Incidents	Number of General Public Incidents	1	0	0	0	0	2	0.0
			Rate per 10, 100, 1000 km of Line	0.208	0	0	0	0	0.402	0.0
	System Reliability	SAIDI		1.83	1.46	1.71	2.36	1.52	1.13	1.33
		SAIFI		1.56	1.70	2.41	2.02	1.35	1.14	1.08
	Asset Management	Distribution System Plan Implementation		Completed	Completed	Completed	Completed	Completed	Completed	Completed
	Cost Control	Efficiency Assessment		2	2	2	1	1	1	1
		Total Cost per Customer		$ 497	$ 501	$ 512	$ 494	$ 494	$ 518	$ 561
		Total Cost per km		$ 23,937	$ 24,354	$ 24,714	$ 24,038	$ 24,455	$ 26,144	$ 29,198
Financial Performance	Financial Ratios	Liquidity: Current Ratio		1.51	1.53	1.44	1.73	1.58	1.32	1.41
		Leverage: Total Debt to Equity Ratio		0.81	0.77	0.83	0.97	0.91	0.86	0.92
		Profitability: Regulatory Return on Equity		8.51%	11.41%	10.44%	9.36%	10.72%	11.71%	12.97%
Asset and/or System Operations Performance	Distribution Losses	Percentage Line Losses		3.99%	3.70%	3.65%	4.03%	3.98%	3.93%	4.06%

Table 5.2-8: WHESC Performance - Historical Period

5.2.3.1.1 Objectives for Continuous Improvement Set Out in Last DSP Filing

In WHESC's previous DSP, objectives for continuous improvement were generally to meet or exceed OEB targets for the metrics shown in Table 5.2-8. In a few categories, WHESC established specific targets that exceeded OEB values. For the currently relevant measures, WHESC's previously established target, 2017 performance, 2023 performance, and the historical average are shown in Table 5.2-9, below.

Performance Category	Measures		WHESC Target	2017	2023	Historical Average
Service Quality	New Residential/Small Business Services		90.0%	100.00%	95.53%	97.74%
	Scheduled Appointments Met On Time		90.0%	98.64%	94.88%	95.96%
	Telephone Calls Answered on Time		65.0%	96.19%	76.33%	86.54%
Customer Satisfaction	First Contact Resolution		80.0%	75.00%	99.70%	87.34%
	Billing Accuracy		99.5%	99.98%	99.97%	99.96%
	Customer Satisfaction Survey Result		90% - "A" Grade	92.00%	98.00%	96.00%
Safety	Level of Public Awareness		80%	83.00%	83.00%	83.00%
	Level of Compliance with Ontario Regulation 22/04		C	C	C	C
	Serious Electrical Incidents	Number of General Public Incidents	0	1	0.0	0.4
		Rate per 10, 100, 1000 km of Line	0	0.208	0.0	0.087
System Reliability	SAIDI		2.0	1.83	1.33	1.62
	SAIFI		1.8	1.56	1.08	1.61
Asset Management	Distribution System Plan Implementation		Completed	Completed	Completed	Completed
Cost Control	Efficiency Assessment		2	2	1	1
	Total Cost per Customer		2.5% Increase Annually	$ 497	$ 561	2.1% Average Increase Annually
	Total Cost per km		2.5% Increase Annually	$ 23,937	$ 29,198	3.6% Average Increase Annually
Financial Ratios	Liquidity: Current Ratio		Greater than 1.0	1.51	1.41	1.50
	Leverage: Total Debt to Equity Ratio		Less than 1.5	0.81	0.92	0.87
	Profitability: Regulatory Return on Equity		Within +/- 3% of 8.78%	8.51%	12.97%	10.73%
Distribution Losses	Percentage Line Losses		Not Exceeding 4.29%	3.99%	4.06%	3.91%

Table 5.2-9: WHESC Performance Against Previous DSP Objectives

Section 5.2.3.2 provides an overview of WHESC's historical performance in each category. In general, the objectives set out in WHESC's last DSP have been achieved. Areas where the objectives have not been achieved on an average basis are:

- Serious Electrical Incident Occurrence and Rate

  Welland Hydro continues to manage the safety of the general public and it's employees as a top priority and believes it is prudent to continue to strive for zero serious electrical incident occurrences. The occurrences in the historical period are summarized in Section 5.2.3.2.2. While factors influencing occurrences are not always in WHESC's direct control, investments identified in this DSP have been prioritized against health and safety outcomes that are in the control of the distributor.

- Total Cost Per km Annual Increase:

  WHESC's objective in the last DSP was to maintain a total cost per km below a 2.5% increase annually. While this objective was not met, it is notable that the objective of total cost per customer was exceeded. A factor in this measure is the impact of WHESC's rebuild and voltage conversion efforts on total circuit km's of line. In some cases, a rebuild/conversion project results in the elimination of circuit(s), placing downward pressure on total circuit kilometres.

With reference to Table 5.2-9, there are a few notables areas in which WHESC exceeded targets established in the previous DSP. These are:

- Customer Satisfaction Survey Result

  WHESC most recent survey result yielded a 98% customer satisfaction rate, well above the provincial average in 2023 of 90%. WHESC's customer satisfaction result has increased over the historical period. Reliability performance and affordability remain top areas of concern for LDC customers and WHESC's performance in both areas are indicative of the survey results.

- Efficiency Assessment

  WHESC has implemented efficiency measures in the historical period resulting in a ranking that moved WHESC to Cohort 1 in 2020.

5.2.3.2 Service Quality and Reliability

5.2.3.2.1 Customer Focus

The two key performance categories related to the "Customer Focus" performance outcome are "Service Quality" and "Customer Satisfaction". WHESC's performance in each of these categories is shown in Table 5.2-10, for the historical period 2017 to 2023.

Performance Outcome	Performance Category	Measures	2017	2018	2019	2020	2021	2022	2023
Customer Focus	Service Quality	New Residential/Small Business Services	100.00%	100.00%	94.82%	94.52%	99.68%	99.61%	95.53%
		Scheduled Appointments Met On Time	98.64%	94.90%	93.16%	98.28%	97.88%	93.99%	94.88%
		Telephone Calls Answered on Time	96.19%	97.29%	88.90%	86.15%	83.07%	77.88%	76.33%
	Customer Satisfaction	First Contact Resolution	75.00%	80.00%	80.00%	77.00%	99.89%	99.81%	99.70%
		Billing Accuracy	99.98%	99.99%	99.99%	99.99%	99.91%	99.88%	99.97%
		Customer Satisfaction Survey Result	92.00%	96.00%	96.00%	96.00%	96.00%	98.00%	98.00%

Table 5.2-10: Customer Focus Outcomes

Service Quality

WHESC follows the OEB targets for service quality-based metrics. Historically, WHESC has exceeded the OEB target of 90% for new residential and small business services connected within five business days or less. WHESC uses a software-based tracking tool for new services that manages pre-requisites for a new connection to proceed. Operations staff leverage this tool to ensure that new service connections are expedited once all pre-requisites are met.

WHESC also tracks whether scheduled appointments are met on time through its work force management software. WHESC has exceeded the OEB target of 90% for this measure in each year of the historical period.

Additionally, WHESC's telephone system tracks the time elapsed before staff answer inbound calls in queue.

WHESC's performance against the "Telephone Calls Answered on Time" measure has declined over the historical period. Although still exceeding the OEB target of 65% or greater, WHESC attributes the decline in performance to growth and associated workload demand for new/upgrade service processing through the customer service department. WHESC has identified resource adjustments in the COS filing associated with this DSP, with the intention of addressing declining performance.

Customer Satisfaction

WHESC has improved its performance over the historical period, resolving a customer's inquiry on first contact over 99% of the time. Billing accuracy continues to remain well above the OEB defined target of 98%

WHESC conducts bi-annual customer satisfaction surveys to determine how the LDC is performing against both provincial and national peers. The latest survey was conducted in 2022 and 98% of customers indicated they are satisfied with the overall service level provided by WHESC. The survey helps inform WHESC's future investment planning. Customers continue to indicate that affordability and service reliability are the most important considerations related to WHESC's service.

5.2.3.2.2 Operational Effectiveness

The four key performance categories related to the "Operational Effectiveness" performance outcome are "Safety", "System Reliability", "Asset Management", and "Cost Control". WHESC's performance in each of these categories is shown in Table 5.2-11, for the historical period 2017 to 2023.

Performance Outcome	Performance Category	Measures		2017	2018	2019	2020	2021	2022	2023
Operational Effectiveness	Safety	Level of Public Awareness		83.00%	83.00%	83.00%	83.00%	83.00%	83.00%	83.00%
		Level of Compliance with Ontario Regulation 22/04		C	C	C	C	C	C	C
		Serious Electrical Incidents	Number of General Public Incidents	1	0	0	0	0	2	0.0
			Rate per 10, 100, 1000 km of Line	0.208	0	0	0	0	0.402	0.0
	System Reliability	SAIDI		1.83	1.46	1.71	2.36	1.52	1.13	1.33
		SAIFI		1.56	1.70	2.41	2.02	1.35	1.14	1.08
	Asset Management	Distribution System Plan Implementation		Completed	Completed	Completed	Completed	Completed	Completed	Completed
	Cost Control	Efficiency Assessment		2	2	2	1	1	1	1
		Total Cost per Customer		$ 497	$ 501	$ 512	$ 494	$ 494	$ 518	$ 561
		Total Cost per km		$ 23,937	$ 24,354	$ 24,714	$ 24,038	$ 24,455	$ 26,144	$ 29,198

Table 5.2-11: Operational Effectiveness Outcomes

Safety

WHESC has met or exceeded the OEB defined metrics related to the safety of employees and the public, throughout the historical period. WHESC conducts bi-annual electrical safety awareness surveys to confirm the public's understanding of electrical hazards related to our distribution system.

WHESC continues to maintain full compliance with Ontario Regulation 22/04. Maintenance, operation, and implementation of new distribution system plant adheres to Electrical Safety Authority (ESA) guidelines based on annual third party audit findings.

A requirement of Ontario Regulation 22/04 is the reporting of serious electrical incidents. Generally, any time a portion of the electrical system operating over 750 V interacts with the public space, the incident is reportable with a few exceptions. For 2017, WHESC reported one serious electrical incident. Following a fault on WHESC's 4.16 kV system, a restricted conductor failed and entered the public space in an energized condition.

In 2022, WHESC reported two serious electrical incidents. One was attributed to a member of the public vandalizing a 4.16kV distribution pole, causing primary conductor to enter the public space.

The second was due to failure of a primary connector on the 4.16kV system, causing a primary conductor to enter the public space.

These events did not result in injury to a member of the public or WHESC staff. The incidents along with those not meeting ESA's reporting criteria are reviewed at Operations Committee meetings. Negative trends are identified along with opportunities for corrective action. In addition to taking steps to increase electrical safety awareness to the public within our service area, WHESC has incorporated mitigation of known safety risks into its capital investment plans. There are several system renewal projects incorporating the removal of restricted conductor from the distribution system.

Reliability

System Reliability Performance is documented in detail in Section 5.2.3.2.5.

Asset Management

WHESC's last DSP covered the period 2017 through 2021. WHESC tracked DSP progress through Operations Committee review of annual variances. Throughout the period, WHESC generally met or exceeded planned expenditures. The 2018 ACA report provided valuable insight into the annual capital planning process, influencing internally driven expenditures and system renewal pacing to sustain asset health.

Cost Control

WHESC moved to Cohort 1 based on Pacific Economics Group's benchmarking and efficiency assessment in 2020. Cost per customer has remained stable through the historical period, below the pace of inflation and growth.

In the historical period, WHESC invested in grid modernizing technology to improve grid visibility and operational response to unplanned events. Refer to Section 5.3.1.2.7 for additional details. WHESC continues to evaluate shared service model approaches to improving performance outcomes at managed cost.

5.2.3.2.3 Financial Awareness

The three key performance categories related to the "Financial Performance" outcomes are "Liquidity", "Leverage", and "Profitability". WHESC's performance in each of these categories is shown in Table 5.2-12, for the historical period 2017 to 2023.

Performance Outcome	Performance Category	Measures	2017	2018	2019	2020	2021	2022	2023
Financial Performance	Financial Ratios	Liquidity: Current Ratio	1.51	1.53	1.44	1.73	1.58	1.32	1.41
		Leverage: Total Debt to Equity Ratio	0.81	0.77	0.83	0.97	0.91	0.86	0.92
		Profitability: Regulatory Return on Equity	8.51%	11.41%	10.44%	9.36%	10.72%	11.71%	12.97%

Table 5.2-12: Performance Metrics - Financial Ratios

As an indicator of financial health, a liquidity ratio (current assets / current liabilities) greater than 1.0 is a good indicator that WH can pay its short term debts and meet financial obligations. WHESC has consistently maintained a liquidity ratio above 1.0.

The OEB has set a deemed capital structure of 60% debt and 40% equity for LDCs operating in Ontario. This deemed structure assumes a debt-to-equity ratio of 1.5 (60/40). A debt-to-equity ratio greater than 1.5 indicates that a distributor is more leveraged than the deemed capital structure. WHESC has consistently operated with a debt-to-equity ratio below 1.0 in the historical period. This demonstrates that WHESC is able to leverage additional debt should this be required to fund capital investment.

WHESC's deemed regulatory return from the 2017 COS was 8.78%. The OEB allows a distributor to earn within +/-3% of the expected Return on Equity (ROE). In 2023, WHESC exceeded the +3% deadband due to stronger than normal growth and unanticipated FTE losses. Prior to 2023, WHESC's achieved ROE was within the +/-3% deadband. WHESC views the conditions experienced in 2023 to be anomalous, specifically in relation to growth projections. WHESC continues to rely on load projections established in support of the 2022 IRRP and the subsequent RIP as the basis for growth in the forecast period.

5.2.3.2.4 Distribution Line Losses

WHESC system losses have been tracked over the historical period and are shown in Table 5.2-13, below:

Performance Outcome	Performance Category	Measures	2017	2018	2019	2020	2021	2022	2023
Asset and/or System Operations Performance	Distribution Losses	Percentage Line Losses	3.99%	3.70%	3.65%	4.03%	3.98%	3.93%	4.06%

Table 5.2-13: Performance Metrics – Distribution Losses

Distribution system losses have averaged 3.91% over the historical period, with the most recent year reporting 4.06%. WHESC has demonstrated a consistent ability to manage system losses while growth in connected load and demand continues. WHESC's capital expenditures over the historical period have included voltage conversion on portions of the distribution system from 4.16kV to 27.6kV. Municipal substation upgrades have also occurred whereby replacement power transformer capacity is reduced, typically resulting in a mitigation of system losses.

5.2.3.2.5 System Reliability Performance

Methods and Metrics

WHESC monitors system reliability indices System Average Interruption Duration Index ("SAIDI"), System Average Interruption Frequency Index ("SAIFI"), and Customer Average Interruption Duration Index ("CAIDI") on a monthly basis. The indices and associated trends are reviewed in recurring, board-level Operations Committee meetings.

WHESC's SmartMap system, driven by Advanced Meter Infrastructure ("AMI") and outage calls is the source of information for these indices. SmartMap has predictive algorithms that analyze inbound outage notifications to indicate the most likely protective element that has operated. In conjunction with SCADA observations, WHESC's control room leverages automated devices to expedite restoration of service to customers where possible. Following remote restoration activities, field staff are dispatched to investigate the cause. Control room operators leverage AMI, SmartMap, and SCADA data to capture outage and restoration times, resulting in accurate reporting of customer count, outage duration, and outage cause related to reliability indices.

All outages, including momentary, are tracked. Outages with a duration of greater than 1 minute are included in service reliability indices.

Overall service reliability indices are summarized monthly. The underlying data includes identification of the associated feeders to permit circuit level trending. Trending is reviewed annually to inform system investment decisions.

WHESC's customer engagement activities indicate that service reliability is a high priority for customers. WHESC strives to balance customer and system growth with improving reliability performance. Where deemed beneficial, technology deployments target poor performing portions of the distribution system for mitigation. The OEB scorecard targets for SAIDI and SAIFI are used as the default targets for reliability performance objectives. These are calculated as follows:

- SAIDI: System Average Interruption Duration Index

$$\text{SAIDI} = \frac{\text{Total Customer Hours of Interruption}}{\text{Average Number of Customers Served}}$$

- SAIFI: System Average Interruption Frequency Index

$$\text{SAIFI} = \frac{\text{Total Customer Interruptions}}{\text{Average Number of Customers Served}}$$

WHESC analyzes these performance indices both in total and adjusted for Loss of Supply ("LOS"). In the historical period, WHESC did experience outages caused by LOS at the supplying Crowland TS. WHESC also considered whether significant events over a threshold of SAIDI met the threshold and criteria to be classified as a Major Event Day ("MED"). The contribution to SAIDI of a particular event must meet the calculated threshold for the period (using the IEEE Standard 1366 approach) and must also meet the criteria defining an MED. The MED criteria is generally met if the event was beyond the control of the LDC, was unforeseeable, unpredictable, and unavoidable.

WHESC reports SAIDI and SAIFI to its Operations Committee in total, adjusted for LOS, and adjusted for MED. In the historical period, WHESC did not have a MED. Therefore, the balance of data presented in this section does not include indices adjusted for MED.

Historical Performance

Figure 5.2-11 below indicates the performance for SAIDI for the historical period.

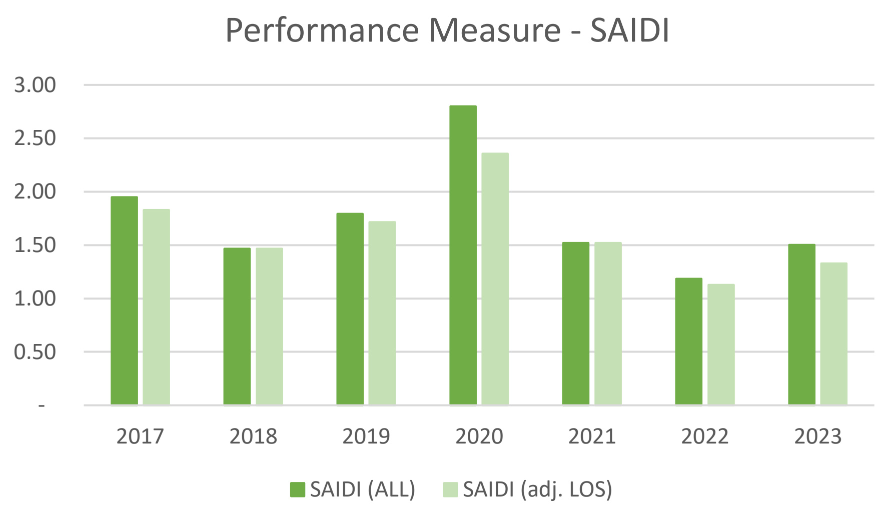


Figure 5.2-11: Annual SAIDI from 2017 to 2023

The performance index in 2020 of 2.36 (adjusted for LOS) included one significant weather event that contributed 0.93 (39%) to the value of SAIDI. This was the most significant outage event in the historical period. The value of SAIDI with this event removed is 1.46 for 2020, which is more in line with the annual trend.

There has been a declining trend in SAIDI from 2017 to 2023. This is largely attributed to the impact of technology deployments integrated with SCADA, and implementation of a 24 x 7 system control coverage model in 2021. These two factors in combination, allow operators to immediately respond to unplanned outages. Faulted sections are isolated through SCADA, minimizing the number of customers affected by the outage and the duration of the event.

Additionally, operators have access to SmartMAP which provides basic Outage Management System ("OMS") functionality. SmartMAP analyzes integrated AMI outage and restoration notifications along with customer calls to predict the failed device location. Operators are notified of both device operations from SCADA and predicted outages from SmartMAP, on a 24 x 7 basis.

There outage events inclusive of outage cause code LOS in the historical period were caused by HONI owned and operated breaker failure conditions that resulted in bus outages. WHESC formally requested preventative maintenance on the devices in question at various points in this historical period. HONI completed refurbishment work based on these requests.

Figure 5.2-12 illustrates SAIFI performance for the historical period.

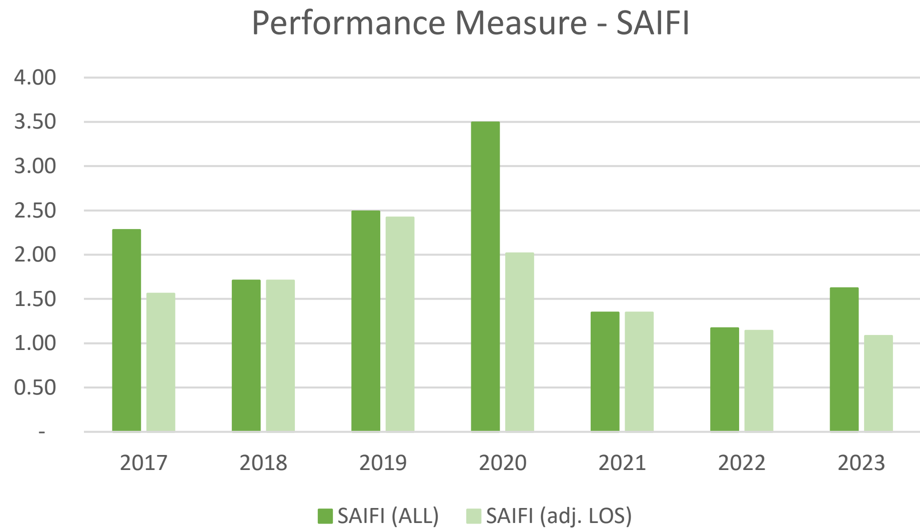


Figure 5.2-12: Annual SAIFI from 2017 to 2023

SAIFI was highly influenced by LOS induced events over the historical period. Station bus outages, affecting approximately ½ of WHESC's customer base in each instance, caused a significant number of customers to experience an outage than would have been the case otherwise. The reason that SAIDI wasn't as significantly affected was the ability for WHESC to immediately transfer load to the other station bus, via SCADA controlled, external tie points within its distribution system. When feeder interties are constructed, redundancy between station bus supply points is considered.

Observing SAIFI adjusted to exclude LOS, there has been a declining trend over the historical period. The declining trend is for the same reasons identified above pertaining to the trend in SAIDI.

The table below summarizes SAIDI and SAIFI for the period 2017 to 2023. WH confirms that the data presented in Table 5.2-14 is consistent with the data reported in support of the annual scorecard of electricity distributors.

Index	2017	2018	2019	2020	2021	2022	2023	Historical Average
SAIDI - excluding LOS	1.83	1.46	1.71	2.36	1.52	1.13	1.33	1.62
SAIFI - excluding LOS	1.56	1.70	2.41	2.02	1.35	1.14	1.08	1.61
SAIDI - including LOS	1.95	1.46	1.79	2.80	1.52	1.18	1.50	1.74
SAIFI - including LOS	2.28	1.70	2.48	3.50	1.35	1.17	1.61	2.01
SAIDI - excluding LOS & MED	1.83	1.46	1.71	2.36	1.52	1.13	1.33	1.62
SAIFI - excluding LOS & MED	1.56	1.70	2.41	2.02	1.35	1.14	1.08	1.61

Table 5.2-14: Historical System Reliability Indices

As evident in the Table 5.2-14, WHESC has not reported any Major Events for the 2017 to 2023 historical period. While WHESC did experience significant weather events, none met the definition and criteria for a Major Event as defined in Section 2.1.4.2 of the RRR reporting requirements.

Outages by Cause Code

The following sections and figures provide the breakdown of historical outages for the period 2017 to 2023 regarding the number of outages, number of customers interrupted, and number of customer hours experienced by the outages. Tracking outage performance by cause code provides invaluable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the five-year historical performance range is used as a target and results outside this range indicate positive or negative trending.

Outage Occurrences

Table 5.2-15 summarizes the number of outage occurrences by year for the period 2017 to 2023:

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total # of Outages	%
0 - Unknown/Other	2	3	0	0	1	5	3	14	0.8%
1 - Scheduled Outage	180	160	160	184	167	35	87	973	58.4%
2 - Loss of Supply	1	0	3	13	0	2	3	22	1.3%
3 - Tree Contact	4	8	20	2	15	9	5	63	3.8%
4 - Lightning	0	0	0	4	5	3	0	12	0.7%
5 - Defective Equipment	34	31	36	64	24	19	26	234	14.0%
6 - Adverse Weather	35	44	65	36	28	21	15	244	14.6%
7 - Adverse Environment	0	0	0	0	0	0	0	0	0.0%
8 - Human Element	0	2	5	1	2	0	2	12	0.7%
9 - Foreign Interference	11	17	4	14	20	10	17	93	5.6%
Total	**267**	**265**	**293**	**318**	**262**	**104**	**158**	**1,667**	**100.0%**

Table 5.2-15: Historical Outage Occurrences

Figure 5.2-13 shows the annual trend in total outage occurrences over the historical period. As scheduled outages for performing construction and maintenance tend to be the leading cause annually, there has been a concerted effort to reduce these occurrences. Strategies include coordination of maintenance activities, more extensive use of utility arborists to reduce outage scope and using third party services to tension string in proximity to energized circuits. Although there can be a large volume of scheduled outages in a year, the number of customers affected per outage is typically small.

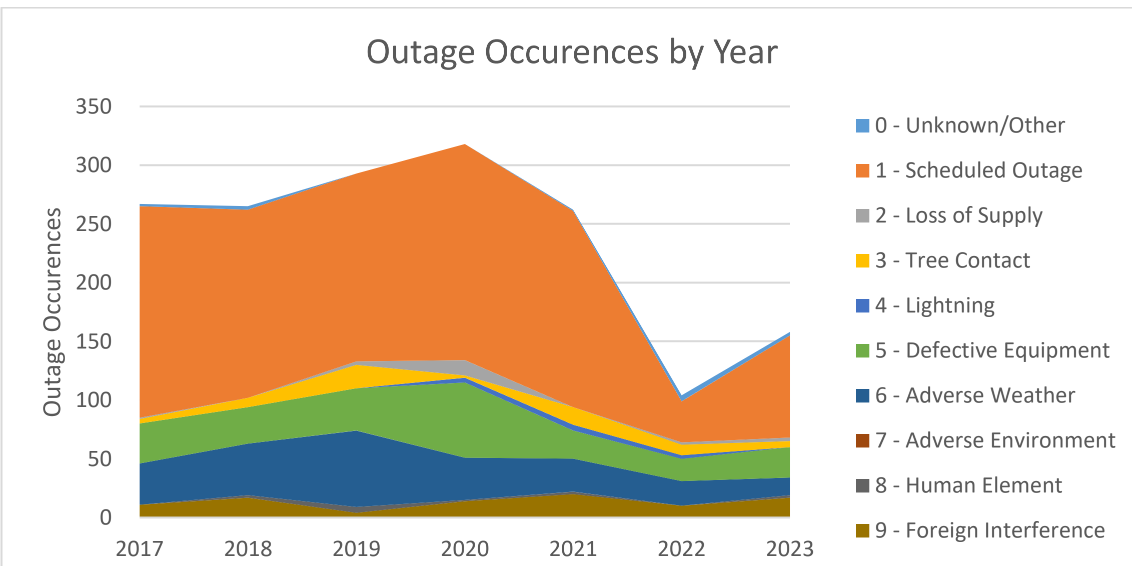


Figure 5.2-13: Historical Outage Occurrences by Year

Customers Interrupted by Cause Code

Table 5.2-16 provides an annual summary the number of customer interruptions by cause code.

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total Customer Interruptions	%
0 - Unknown/Other	493	514	0	0	35	5,460	71	6,573	2.0%
1 - Scheduled Outage	4,376	7,457	2,959	3,744	3,428	3,878	2,555	28,397	8.4%
2 - Loss of Supply	16,477	0	1,645	35,415	0	742	13,515	67,794	20.1%
3 - Tree Contact	95	4,830	12,171	27	9,771	768	146	27,808	8.3%
4 - Lightning	0	0	0	4,769	5,163	56	0	9,988	3.0%
5 - Defective Equipment	9,046	2,674	5,552	9,732	2,234	10,222	2,208	41,668	12.4%
6 - Adverse Weather	19,313	22,002	35,536	27,329	4,205	5,305	4,492	118,182	35.1%
7 - Adverse Environment	0	0	0	0	0	0	0	0	0.0%
8 - Human Element	0	40	495	10	412	0	491	1,448	0.4%
9 - Foreign Interference	2,382	2,020	66	2,490	7,566	2,668	17,449	34,641	10.3%
Total	**52,182**	**39,537**	**58,424**	**83,516**	**32,814**	**29,099**	**40,927**	**336,499**	**100.0%**

Table 5.2-16: Customer Interruptions by Cause Code

Figure 5.2-14 depicts the number of customers interrupted annually, by outage cause. LOS events have a significant influence on the number of customers interrupted. As mentioned previously, these outages impact many customers per occurrence, approaching ½ of WHESC's customer base.

Customers impacted by adverse weather have diminished over the historical period. This is in part due to the significance of weather events experienced. It is also in part due to the grid modernization deployments over the period. SCADA controlled devices, strategically deployed to sectionalize feeders by customer count or length of line, reduce the number of customers initially impacted by the event. These devices were deployed with a protection coordination scheme, such that fault isolation is on a section of line rather than the entire feeder. Devices can operate as a line recloser, sectionalizer, or switch, and the mode of operation can be changed remotely based on system configuration.

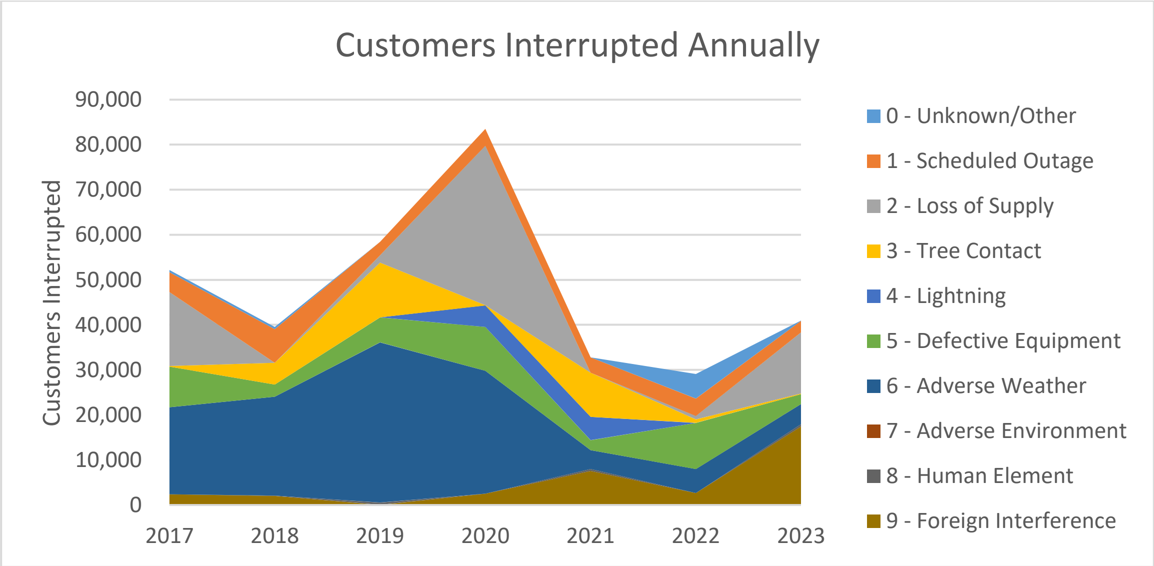


Figure 5.2-14: Customer Interruptions Annually

Customer Hours of Interruption by Cause Code

Table 5.2-17 summarizes the hours of customer interruption by cause code.

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total Customer Hours	%
0 - Unknown/Other	735	318	0	0	74	4,398	81	5,605	**1.9%**
1 - Scheduled Outage	13,449	8,300	8,435	9,811	7,669	5,783	9,553	63,000	**21.5%**
2 - Loss of Supply	2,746	0	1,823	10,616	0	1,396	4,409	20,991	**7.2%**
3 - Tree Contact	137	2,126	5,449	9	8,788	1,604	119	18,231	**6.2%**
4 - Lightning	0	0	0	3,317	2,155	228	0	5,700	**1.9%**
5 - Defective Equipment	9,071	3,371	2,723	6,300	3,105	8,719	4,175	37,464	**12.8%**
6 - Adverse Weather	16,328	18,249	23,027	31,368	8,406	5,691	8,373	111,442	**38.1%**
7 - Adverse Environment	0	0	0	0	0	0	0	0	**0.0%**
8 - Human Element	0	11	612	13	214	0	109	960	**0.3%**
9 - Foreign Interference	2,189	1,573	72	5,434	6,676	1,998	11,231	29,171	**10.0%**
Total	**44,654**	**33,947**	**42,141**	**66,869**	**37,086**	**29,818**	**38,050**	**292,566**	**100.0%**

Table 5.2-17: Customer Hours of Interruption by Cause Code

In addition to the number of customers affected by outages caused by adverse weather declining over the historical period, the associated outage duration per customer did as well. Again, this is partly attributed to grid modernization initiatives that reduce the number of customers affected, and in turn the total number of customer hours of interruption.

The LOS caused events resulted in less of an impact on customer hours of duration due to WHESC's ability to transfer load to alternate sources. As stated previously, load transfers took place immediately following LOS events at Crowland TS.

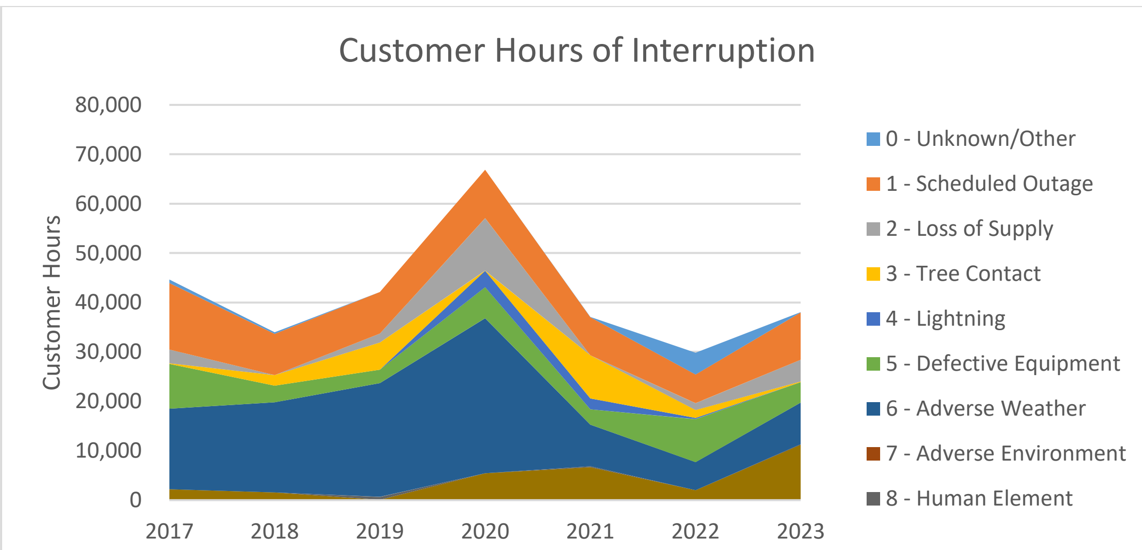


Figure 5.2-15: Customer Hours of Interruption Annually

5.2.3.3 Distributor Specific Reliability Targets

WHESC uses the Reliability Targets as specified by the *Report of the OEB: Electricity Distribution System Reliability Measures and Expectations.* WHESC's performance expectations are set based on historical performance which has been found to be a reasonable method to report on the effectiveness of reliability programs.

5.3 Asset Management Process

This section provides an overview of WHESC's asset management process and the links between this process and the expenditure decisions that comprise WHESC's capital investment plan.

5.3.1 Planning Process

5.3.1.1 Overview of the Planning Process

WHESC is committed to distributing electricity in a safe, reliable, affordable, and sustainable manner. This underlying objective is the foundation of our asset management process and influences WHESC's planning decisions.

The asset management process facilitates the operation, maintenance, and investment in new or replaced distribution system assets. The process seeks to align long term asset management strategies with strategic objectives and corporate goals. Process outcomes related to safety, reliability, and affordability are regularly reviewed such that there is continual improvement driving system performance.

WHESC planning process incorporates key objectives in alignment with the corporations strategic objectives. The following asset management objectives have been established:

- Health and Safety Performance: WHESC must maintain and operate its distribution system in a manner that places public and worker health and safety as the top priority. Assets are maintained and operated such that risk to the public is mitigated to the greatest extent possible.
- Asset Performance: Asset condition is a key driver influencing WHESC's investment decisions. WHESC has conducted Asset Condition Assessments (ACA) to better inform and prioritize investments. Asset health is continuously evaluated with the objective of sustaining asset condition.
- Environment: WHESC's asset management decisions seek to minimize impact to the environment in which its infrastructure is deployed. Whether introducing new assets, maintaining existing installations, or operating the system, WHESC's objective is mitigate environmental risk. The process includes consideration of risks associated with asset failure.
- Meeting Regulatory and Legal Obligations: WHESC must operate its distribution system in a manner that meets or exceeds regulatory and legal requirements.
- System Capacity: WHESC considers the ability of the distribution system to supply the changing needs of the existing customer base along with demand from new customer connections.
- System Reliability: WHESC is committed to managing system reliability through scenarios of customer growth and climate change impacts. Asset health sustainment decisions, grid modernization initiatives, and continued enhancement of grid visibility are key areas of focus in order to achieve this objective.
- Operational Efficiency and Affordability: WHESC's has demonstrated its commitment to providing reliable service while managing costs to the customers it serves. Sustaining this level of performance is a key objective when considering operating and maintenance activities and system investment decisions.

WHESC's asset management objectives are designed to achieve the desired RRFE outcomes and align with corporate goals. Table 5.3-1 below indicates the relationship between the RRFE outcomes and WHESC's corporate goals, asset management objectives, and project ranking criteria.

RRFE Outcome	Corporate Goal	Asset Management Objective	Weight Assignment
Customer Focus	Providing value to customers	Operational Efficiency and Affordability	Medium
Operational Effectiveness	Reliability and resilience	Asset Performance	High
		Environment	High
		Health and Safety Performance	High
		System Reliability	Medium
		System Capacity	High
		Meeting Regulatory and Legal Obligations	High
Financial Performance	Financial Integrity within OEB tolerances	Operational Efficiency and Affordability	Medium
		Meeting Regulatory and Legal Obligations	High
	Balanced approach to capital spending	Operational Efficiency and Affordability	Medium
Public Policy Responsiveness	Public Policy Compliance	Health and Safety Performance	High
		Meeting Regulatory and Legal Obligations	High

Table 5.3-1: Linkage of WHESC's Asset Management Objectives to Corporate Goals

The corporate goals identified in Table 5.3-1 were established in alignment with WHESC mission statement and in conjunction with the strategic planning objectives. Asset management objectives, designed to achieve these goals are used to determine adherence of investment decisions with the goals of the corporation.

Proposed investments are evaluated against the weighted asset management objectives for the purpose of prioritization. WHESC has assigned the asset management objective weights summarized in Figure 5.3-1. These values have been established to ensure asset management investment decisions best align with corporate goals and objectives. The projects summarized in Table 5.4-17 and Table 5.4-18 illustrate how projects are ranked against these weighted objectives.

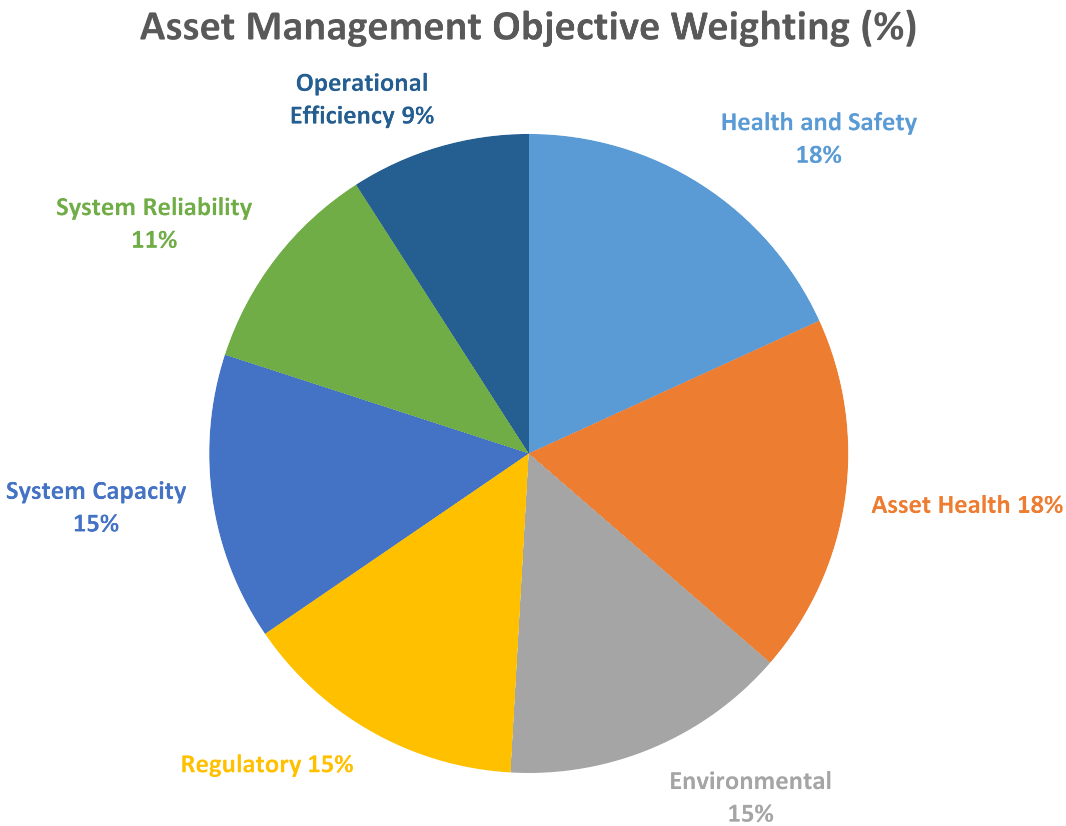


Figure 5.3-1: Asset Management Objective Weighting

5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

5.3.1.2.1 Asset Condition Assessments

Since WHESC's previous DSP filing, WHESC has performed two formal ACAs. In 2018, WHESC performed its first formal ACA, the results of which were used to better inform investment decisions, particularly those categorized as system renewal.

In 2023, WHESC performed another ACA in order to inform investment decisions in this distribution planning cycle. The availability of data from WHESC's GIS has improved since the last ACA was performed, either from an increased volume of data in each asset class, or from a better integrity of asset class data.

The results of the 2023 ACA have been used to better inform internally driven investment decisions in both the system renewal and general plant categories of investment.

5.3.1.2.2 Asset Health Tracking in GIS

Data collection processes, asset condition mitigation measures, and asset health data are all captured within WHESC's GIS system. This aggregation of data supports identification of internally driven investment needs based on asset condition. Proposed projects are modelled in the GIS system and the derived priority of the investment tracked for analysis purposes.

5.3.1.2.3 Pole Testing Enhancements

WHESC now performs cyclical comprehensive pole testing and overhead inspection on its entire asset base, replacing the previously implemented hybrid approach that incorporated visual inspection methods. Section 5.3.3.2.4 provides additional detail on WHESC's pole testing and inspection program. WHESC pole inspections are now inclusive of a non-destructive test method called "Polux" on all WHESC owned pole assets. This results in an accurate depiction of pole integrity, better informing ACAs and ultimately renewal based investment decisions.

5.3.1.2.4 Work Estimating System Integration

WHESC uses Quadra job costing software, integrated within its financial systems. The system houses WHESC engineering standards and associated resource costs for project execution. Engineering technicians utilize this software in conjunction with GIS based designs to schedule and track projects, produce estimates, and allocate material to work orders. The platform also supports variance analysis based on integration with the financial system, Microsoft Dynamics GP ("Great Plains").

Quadra replaced legacy work estimating system and processes. WHESC's proposed investments are fully supported by Quadra based estimates to improve budget to actual variances. Through the job closeout review process, WHESC intends to observe continual improvement in project estimates over time.

5.3.1.2.5 Data Analytics

WHESC implemented the SmartMAP hosted solution, integrating all operational data into a single platform. SmartMAP is a map based product that models WHESC's distribution system, inclusive of primary and secondary systems. The system operating state is presented in real time, leveraging data from meters, automated switches, and fault indicators. System control operators utilize the system to analyze real time metrics such as power flow, voltage stability, and outage conditions. All operational WHESC staff have real time access to voltage performance, asset utilization, and outage occurrences, presented in a dashboard format.

Full integration with the following systems has been achieved in the SmartMap platform:

- AMI
- C&I Settlement Systems
- CIS
- GIS
- SCADA

SmartMAP provides system planners with a single view into near real time operational data, better informing both short and mid-term investment decisions. The system benefits not only planning processes but also provides real time data analytics to support WHESC's day-to-day operations.

5.3.1.2.6 Municipal Coordination

In continued partnership with local government stakeholders, WHESC attends weekly pre-consultation sessions for new developments in the City of Welland, as described in Section 5.2.2.4. This affords an opportunity for developers to understand any pre-requisites for electricity supply needs. It also provides WHESC with important signaling regarding pending capacity and system reinforcement needs.

This approach has been observed to be beneficial to all stakeholders involved, allowing WHESC to support accelerated housing initiatives occurring or contemplated within the area that it serves. WHESC's is better informed to make decisions in the system access and system renewal category of investments based on information gathered in these sessions.

5.3.1.2.7 Grid Modernization

WHESC has continued to invest in its SCADA system, stabilizing its existing fleet of legacy remote controlled switches and adding new automated devices under the system service category of investment. In 2020, WHESC completed a protection study on its main 28 kV distribution system. Following this, WHESC implemented a new protection scheme on this system, introducing reclosing and sectionalizing devices. These devices are fully integrated with SCADA. Modern relaying and data acquisition systems were also installed in the fleet of WHESC's 13 distribution substations supplying the 4.16 kV distribution system.

WHESC implemented a 24 x 7 system control coverage model. This allows system operators to fully leverage technology deployments at any time that a system disturbance requires management. System operators have full access to SCADA, SmartMap, and detailed GIS information on a 24 x 7 basis. The system control service and associated costs are shared between WHESC and another GSC partner LDC. As a result, both entities reap the benefits of a 24 x 7 coverage model with managed costs. The specific associated costs incurred by WHESC are lower than historical experience, when contract services were acquired to provide 24 x 7 coverage.

5.3.1.3 Process

The planning process generally focuses on the determination of which investments are included in the five year business plan. The objective of WHESC's planning process is to address the needs resulting from internal drivers, external drivers, and strategic business objectives. Projects are prioritized for implementation once all mandatory expenditures have been addressed in the capital investment plan. The process followed is generally depicted in Figure 5.3-2 and is as follows:

5.3.1.3.1 Perform Needs Assessment

There are three high level categories of input to the needs assessment process. These are external drivers, internal drivers, and strategic investments.

External Drivers

External drivers are inclusive of new / modified customer connections, customer preferences, municipal project coordination, and regulatory requirements. The investment requirements stemming from these drivers are typically mandatory in nature and can arise at any point in time, causing the need to adjust project prioritization. WHESC typically considers adjustment to non-mandatory project pacing in order to levelize net capital spending, mitigating the expenditure level volatility that can arise from the influence of external drivers.

A key driver to the planning process is load forecasting. WHESC has most recently performed load forecasting in support of the 2022 IRRP report and the 2023 RIP described in Section 5.2.2.8. The load forecast includes new and committed customers and is informed by Welland's Official Plan which incorporates a growth management plan. WHESC is aware of the Regional Planning Process Advisory Group's recent guidance for the development of regional planning demand forecasts and intends on following these guidelines in support of subsequent IRRP cycles. This guidance was provided when the IRRP report was in final draft. The demand forecast methodology used in the Niagara IRRP is documented in Appendix B of the December 22, 2022 report.

WHESC has considered the impact of electrification on load forecasts impacting the distribution system. In March of 2023, the group of GSC partner LDC's commissioned an electrification strategy report, completed by HATCH. The report provided forecast EV growth rates specific to WHESC. The expected growth rate in the next five year period is 15x current deployment levels which are not significant, the lowest amongst GSC LDCs. The result is no material impact on load forecasting related to the distribution system in the forecast period.

The report also summarized the impact on winter peak due to the electrification of space and water heating. WHESC does not expect the distribution system winter peak to exceed the summer peak in the forecast period.

Internal Drivers

Internal drivers typically stem from studies or assessments aimed at maintaining asset performance and distribution system reliability. These include:

- Asset Condition Assessment
- Asset Inspection Reports
- Fleet Condition Assessment

- Facility Condition Assessment
- IT / Cybersecurity Assessment
- Feeder Reliability Reports
- Regional Infrastructure Plan Reports

Internal drivers influence a significant portion of WHESC's plan, resulting in asset and system renewal activities.

Strategic Drivers

There are several key strategic drivers as input to the planning process. These include customer preferences, health and safety, environmental, regulatory, reliability, capacity needs and affordability. While internal drivers typically provide analytics that inform WHESC on conditional, reliability, and capacity based indicators of investment requirements, correlation to strategic drivers is required to determine the urgency of a need against corporate objectives. Strategic drivers inform risk and cost based prioritization of potential investments to provide the most beneficial outcome to the performance of the overall distribution system.

5.3.1.3.2 Determine Investment Alternatives to Address Needs

Once the need for an investment is identified, WHESC evaluates alternatives to address requirements. Alternatives may include asset replacement, refurbishment, non-wires solutions, or doing nothing. High level budgetary estimates are produced for the identified options to address the need. The selected alternative is based alignment with evaluation against WHESC's asset management objectives as identified above and is largely influenced by a cost-benefit analysis.

5.3.1.3.3 Prioritize and Select Investments

Identified capital investments are ranked based on alignment with WHESC's corporate goals as described in Section 5.3.1.1. Projects with the highest ranking are proposed for execution in the current budget year, with consideration given to sequencing, appropriate pacing of asset replacements, and levelizing the annual net capital expenditure. Projects not scheduled for execution in the current budget cycle are held over for future years. The output of this process is the proposed capital investment plan.

5.3.1.3.4 Capital Plan Executive Review

The proposed capital investment plan includes projects contemplated for execution in the next business plan cycle (typically in five year intervals). The proposed plan is reviewed by senior management to confirm accommodation of mandated investments (typically in the System Access category) along with alignment to internal drivers and strategic objectives. Senior management may request capital investment plan refinement to levelized capital spending or more appropriately address specific risks.

5.3.1.3.5 Capital Plan Committee Approval

WHESC's Operation Committee is comprised of a subset of WHESC board members with participation of senior management staff as guests. The Committee's role among others includes monitoring, advising, and making recommendations to the Board of Directors of WHESC on matters relating to the establishment, maintenance and review of the Corporation's strategies, goals, and policies relating to human resources, risk management, environment, and health and safety. The capital investment plan is presented to the Operations Committee, as updated annually, for review and approval. The Operations Committee will recommend the capital investment plan, with any recommended revisions, to the Audit and Finance committee for review.

5.3.1.3.6 Approval of Business Plan

Business Plan Formulation

Senior management maintains a five-year business plan, inclusive of the recommended capital investment plan. The business plan includes capital and operating budgets along with financial metrics to demonstrate alignment to the corporation's strategic objectives and goals.

Board Level Approval

The business plan is presented to the Audit and Finance committee for review. The Audit and Finance Committee is a standing committee of the board of directors whose purpose is to ensure quality financial reporting and sound internal controls are in place; assess the quality of financial reporting, accounting principles and underlying risks; and assess the adequacy and effectiveness of internal controls.

The Audit and Finance committee reviews the business plan for alignment with the corporation's strategic goals, mitigation of business risk, impact on customers, and to benchmark against historical expenditures. Once reviewed to the committee's satisfaction, the Audit and Finance Committee recommends approval of the business plan to the WHESC board.

5.3.1.3.7 Project Execution

Annually, a work execution plan is drafted and vetted by stakeholders at a standing committee of operations staff. The plan considers pre-requisites for project execution including labour, material, and contract service needs. Externally driven deadlines are also considered. The plan is reviewed and approved by the Director of Engineering and Operations.

The committee, inclusive of the Director of Engineering and Operations, meets bi-weekly to track project execution. Project status is tracked in a centralized data repository.

5.3.1.3.8 Assess Outcomes for Continuous Improvement

At work order closure, the operations staff committee reviews the outcomes of completed projects to capture lessons learned. Opportunities for improvement are reviewed and internal process change recommendations are made to senior management for consideration. Variance analysis is presented to the board level Operations Committee on an annual basis for review. The board level Operations Committee makes recommendations to Senior Management in order to improve alignment with strategic goals and objectives.

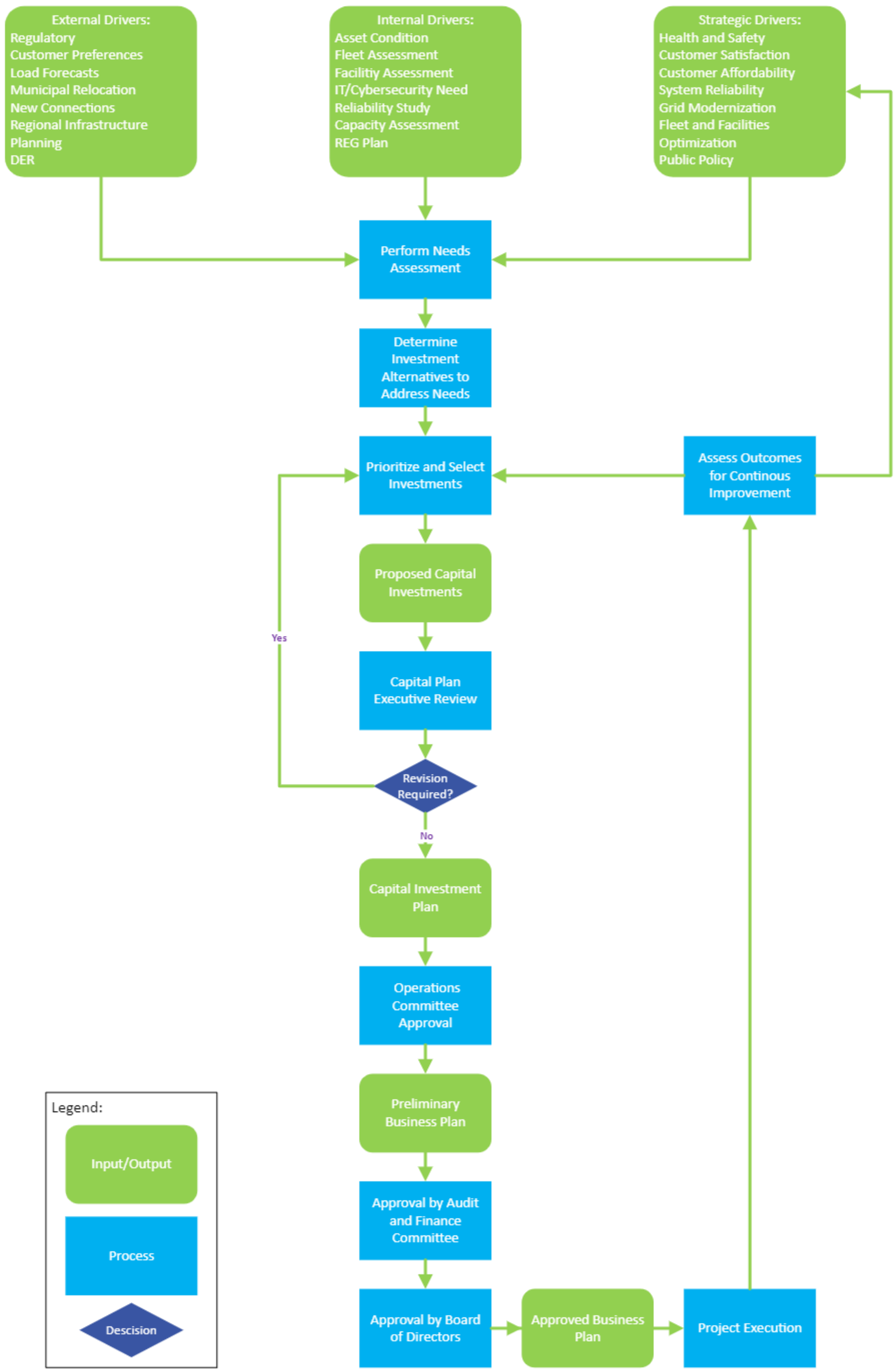


Figure 5.3-2: WHESC's Planning Process

5.3.1.4 Data

WHESC leverages several systems and data repositories for real time analytics and historical information to support capital investment and operating decisions. These include GIS data, condition assessments, inspection data, outage data, asset utilization, protection system data, and customer engagement activity results. The balance of this section summarizes the components of WHESC's asset data repository.

GIS Data

Asset attribute and location data is stored in WHESC's GIS system. This central repository also houses asset inspection data, asset health information, proposed projects, and prioritization. Asset information stored within the GIS includes unique identifiers, asset state, installation, maintenance, and removal information as applicable. The GIS database is integrated with WHESC's operational data platform, SmartMAP via a Multispeak standard interface.

Asset Condition Reports

This DSP is fully supported by an asset condition assessment, completed in 2023. The ACA is the second iteration, following the 2018 report. The ACA leverages GIS data as the primary source of information related to asset attribution, inspection data, fault data, and corrective actions. Supplementary to the GIS, other inputs to the ACA include asset utilization from SCADA and SmartMAP.

Major improvements have been made with regards to WHESC's asset data supporting the latest ACA, as described in Section 5.3.2.2. In most cases, the number of condition parameters used to calculate health indices has improved.

Inspection and Maintenance

WHESC has developed and deployed tablet based mobile solutions to support inspection and maintenance activities including pole inspection, infrared inspection of overhead and underground systems, substation inspections, and tree clearing activities. This allows inspection data to be captured in real time and immediately linked to the associated asset for analysis. WHESC's inspection process meets and exceeds Distribution System Code ("DSC") requirements and is audited annually against Ontario Regulation 22/04. Inspection and Maintenance data forms a key input to the ACA process, via WHESC's GIS.

Asset Utilization

WHESC leverages SmartMAP which aggregates CIS, AMI, C&I, GIS, and SCADA data into a single platform. This supports both real time operational decision making and provides historical trending to support capital investment decisions. The resulting data platform provides a holistic view into the distribution system, particularly regarding asset utilization. From station breakers to distribution transformers, asset loading information is readily available with out of tolerance conditions presented in a dashboard format. The platform enables real time analytics such as Level 2/3 EV charging detection, informing WHESC about both the real time and long-term impacts on distribution transformers and upstream assets. An example of which is depicted in Figure 5.3-3.

Reliability Statistics

Reliability data is captured in SmartMAP which has inputs from customer calls, AMI, and SCADA. The data captured by SmartMAP is analyzed annually to identify negative trends in poor performing feeders or portions of the distribution system. This analysis allows WHESC to target specific areas for mitigation. This data is a fundamental driver of targeted grid modernization deployments and protection system modifications. Mitigation may also include maintenance activities such as additional tree clearing.

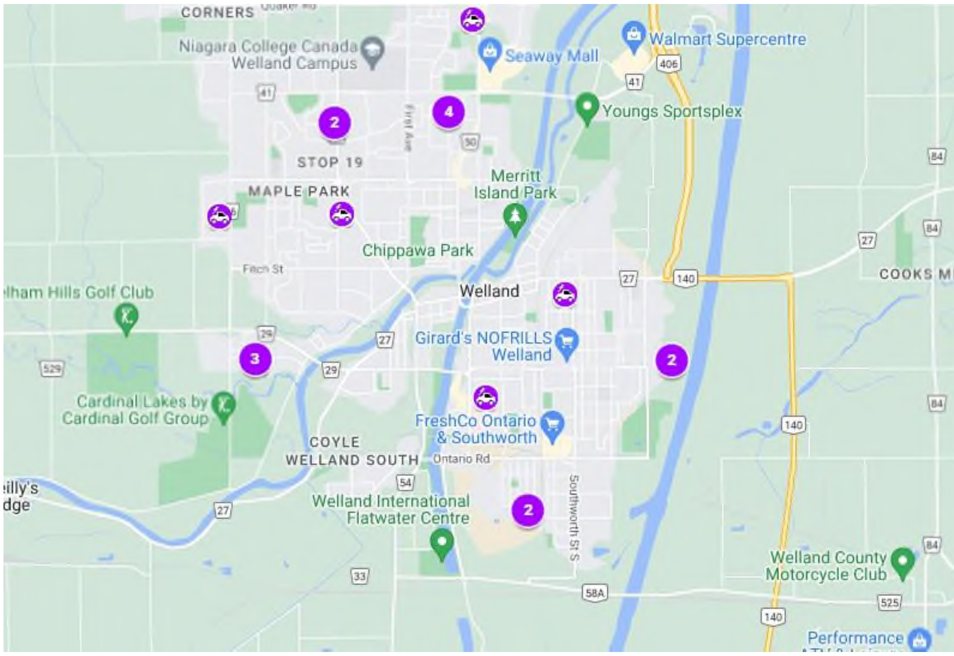


Figure 5.3-3: SmartMAP EV Detection Feature

Grid Visibility Data

WHESC's grid modernization investments have resulted in significant grid visibility improvements. Every 28 kV circuit contains intelligent devices capable of capturing load, fault, and disturbance data. Utilization data is captured in real time by WHESC's SCADA system and pushed to SmartMAP for historical capture and trending. Fault and disturbance data is forwarded to WHESC's system control staff to better inform outage response and outage cause analysis.

Customer Engagement Results

WHESC conducts bi-annual customer satisfaction surveys as described in Section 5.2.2.1. The results of these surveys assist in confirming that corporate goals and strategic objectives are being met and are still appropriate. As part of WHESC's planning process, WHESC conducts customer surveys in order to ensure that customers' preferences inform the appropriateness of investment decisions.

Technological Innovation

Throughout the historical period of this DSP, WHESC has demonstrated a commitment to continuous improvement in meeting its strategic objectives. WHESC monitors technology advancements in the electric utility sector, applying best practices in innovation and technology within its distribution system. Grid visibility enhancements, incorporated into SCADA and SmartMAP provide invaluable analytics leading to operational efficiency. The deployment of remote controlled switches, sensors, reclosers, and sectionalizers, along with protection system automation have demonstrated improvement in system reliability indices. These technologies also position WHESC for future needs, allowing visibility into two-way power flows and short term capacity needs. WHESC already has a significant deployment of DER's within its distribution system. Historical and planned technology deployments on the distribution system, position WHESC to support further DER integration, enabling the capability to support the real time requirements of Distribution System Operator (DSO) concepts.

5.3.2 Overview of Assets Managed

5.3.2.1 Description of Service Area

5.3.2.1.1 Overview of Service Area

WHESC services electricity customers in the City of Welland, shown previously in Figure 5.**2**-**2**. The service territory covers 81 square kilometers with 44% classified as rural and 56% as urban.

WHESC owns, maintains, and operates approximately 498 km (circuit kilometers) of overhead primary distribution feeders and 161 km of underground primary distribution circuits. WHESC receives power from a single Transformer Station ("Crowland TS") which is owned and operated by HONI. The station provides nine 27.6kV feeder breakers to distribute power throughout the City via WHESC's 27.6 kV distribution system. WHESC also maintains a 4kV system, supplied by 13 municipal substations.

5.3.2.1.2 Customers Served

WHESC supplies 25,753 electricity distribution customers as of December 31, 2023, across its service area. The majority of WHESC's customers are classified as: Residential, General Service less than 50 kW ("GS < 50 kW"), or General Service greater than 50 kW ("GS > 50 kW"). WHESC also supplies customers classified as streetlighting, sentinel lighting, and unmetered scattered load which are not included in the total number of customers described above.

Table 5.3-2 below illustrates the changes in WHESC's customer base over the historical period.

Year	Residential	GS<50 kW	GS > 50 kW	Total
2023	23,761	1,847	145	25,753
2022	23,084	1,840	139	25,063
2021	22,654	1,832	141	24,627
2020	22,102	1,791	161	24,054
2019	21,721	1,777	166	23,664
2018	21,399	1,803	164	23,366
2017	21,093	1,796	159	23,048

Table 5.3-2: WHESC's 2017-2023 Actual Customer Base

5.3.2.1.3 System Demand & Efficiency

Table 5.3-3 shows the annual peak demand in kilowatts for WHESC's distribution system.

Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2023	59,556	85,982	65,840
2022	61,728	83,593	65,308
2021	57,133	85,419	64,035
2020	59,059	87,033	64,530
2019	63,018	80,633	62,565
2018	61,224	84,738	67,219
2017	58,098	77,648	60,471

Table 5.3-3: Annual Peak System Demand 2017-2023

WHESC is a currently a summer peaking utility. Year over year variability in the annual peak kW is highly influenced by heating degree days in each period. The data presented in Table 5.3-3 is inclusive of supply from embedded generation.

Table 5.3-4 indicates the efficiency of energy purchased in the historical period. WHESC expects a downward pressure on losses as conversion of load from its 27.6 kV system occurs in the forecast period.

Year	Total Energy Purchased (kWh)	Total Energy Delivered (kWh)	Total Distribution Losses (kWh)	Energy Loss as a % of Purchased kWh
2023	386,506,640	370,827,913	15,678,727	4.06%
2022	392,576,126	377,130,671	15,445,455	3.93%
2021	383,757,520	368,482,783	15,274,737	3.98%
2020	379,962,364	364,637,106	15,325,258	4.03%
2019	384,657,097	370,608,216	14,048,881	3.65%
2018	393,668,076	379,090,833	14,577,243	3.70%
2017	368,796,370	354,086,969	14,709,401	3.99%

Table 5.3-4: Efficiency of Energy Purchased 2017-2023

5.3.2.1.4 Summary of System Configuration

WHESC receives power from a single transformer station (Crowland TS), owned and operated by HONI. The station provides nine 27.6 kV feeder breakers to distribute power throughout the City of Welland via WHESC's distribution system. The 27.6 kV feeders also provide power to WHESC's 13 municipal substations that step voltage down to 4.16 kV. The total load on the 4.16 kV system continues to decrease annually through voltage conversion largely associated with projects in the system renewal category of investment.

27.6 kV Distribution

The 27.6 kV system is configured with over 30 remote controlled switching devices. Generally, each feeder incorporates a mid-point recloser and one or more automatic sectionalizing devices. Critical tie points between circuits contain a remotely controlled switch to expedite fault isolation and load restoration to the extent possible. A comprehensive protection coordination study was completed and implemented in the historical period. This included protection modifications on feeder breaker relaying to improve selectivity on temporary and permanent faults.

Crowland TS also supplies a single feeder to HONI distribution customers. In aggregate, recent historical loading is approaching the limited time rating (LTR) of a single element at the station. The Niagara IRRP, completed in 2022, identified that there is an urgent capacity need in Welland based on load projections. This is depicted in Figure 5.3-4.

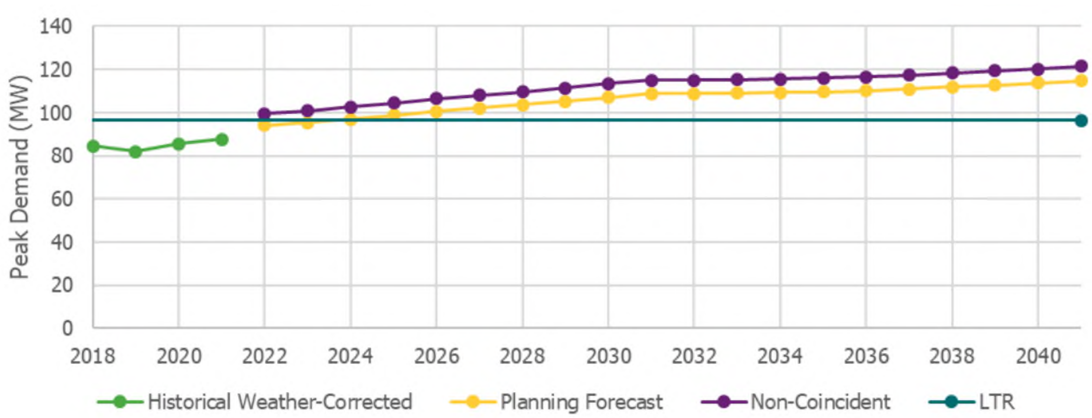


Figure 5.3-4: Crowland TS Capacity Need – 2022 IRRP Report

The RIP that followed the IRRP, proposed a replacement TS, supplied from HONI's 230kV system, increasing the LTR by 75MW. The currently projected in-service date for the replacement TS is 2029. See Section 5.2.2.7 – "Regional Planning Process" for additional details.

4.16 kV Distribution

The 4.16 kV system is configured with 37 remote controlled feeder breakers at each of the 13 municipal substations. All electromechanical and early generation electronic relaying was replaced during the historical period while stations were being upgraded and refurbished. Protection system coordination improvements were made at all 13 substations, inclusive of ground element and single phasing detection.

The 4.16 kV system incorporates loop feed redundancy. A single station contingency can be addressed via load transfers to other connected municipal stations. The following table summarizes the capacity at each of the 13 Municipal Substations:

Station #	Capacity (MW)	2023 Peak (MW)
1	10.0	4.9
2	3.0	1.0
3	8.0	3.1
4	8.0	5.8
5	9.0	5.6
6	3.0	1.9
7	5.0	2.9
8	3.0	1.8
9	4.0	2.6
10	8.0	4.6
11	3.0	1.3
12	6.0	1.9
14	3.0	0.6
Total	73.0	38.0

Table 5.3-5: Municipal Station Capacity – 2023 Peak Data (MW)

5.3.2.1.5 Climate

WHESC's service territory is in the heart of the Niagara Region, lying between Lake Ontario to the North, and Lake Erie to the South. During the historical period, the area has experienced high wind events, with wind gusts exceeding 80 km/h. Ice accumulation events are not uncommon in winter months due to the moderating effects of the great lakes. The Niagara area experiences summer periods of consecutive mid-30 degree C days with humidex values reaching an excess of 40 degrees. Annual system peaks are historically aligned with these periods of high heat.

WHESC recognizes that historical period demonstrated an increased frequency of significant weather events. In support of this DSP, the Customer Survey asked how important it is for us to prepare for extreme weather events that may occur due to climate change. Of the 988 respondents, 78% indicated that climate change preparation is very important to extremely important, with 15% indicating this is somewhat important. WHESC understands that prudent investment directed towards climate change adoption is required. This DSP includes asset replacement and grid modernization concepts designed to improve WHESC's resiliency posture.

5.3.2.1.6 Economic Growth

As observed in Table 5.3-6: Customer Count by Class, WHESC has experienced an increased growth rate in recent years, specifically in the residential customer class. The City of Welland has become increasingly proactive with economic development initiatives aimed at increasing housing starts. With participation by the municipality on the Ontario Governments Building Faster Fund, it is likely that recently experienced residential growth rates will continue. This will continue to have an impact on the level of system access investment required to facilitate new electricity connections. WHESC produced a load forecast in support of the 2022 IRRP. The resulting IESO load forecast for the supplying TS is shown in Figure 5.3-4 (Section 5.3.2.1.4).

Year	Residential	GS<50 kW	GS > 50 kW	Total
2023	23,761	1,847	145	25,753
2022	23,084	1,840	139	25,063
2021	22,654	1,832	141	24,627
2020	22,102	1,791	161	24,054
2019	21,721	1,777	166	23,664
2018	21,399	1,803	164	23,366
2017	21,093	1,796	159	23,048

Table 5.3-6: Customer Count by Class

An objective of WHESC's investment plan is to sustain or improve the reliability of the distribution system as it expands. This is in part a driver of system service based investments, designed to minimize customer exposure during unplanned events and expedite outage restoration.

5.3.2.2 Asset Information

WHESC's key distribution asset categories, the asset population, health index (HI) distribution, and data availability indicators (DAI) are shown in Table 5.3-7, below.

Asset Category	Population	HI Distribution						DAI
		Very Poor	Poor	Fair	Good	Very Good	Invalid HI	
Distribution Assets								
Wood Poles*	7527	591	2223	1724	1065	1924	0**	73%
Bell Wood Poles	795	0	8	533	71	89	94	95%
Concrete Poles	89	1	0	0	63	25	0	100%
Pad-Mount Transformers	853	0	0	7	59	786	1	100%
Pole-Trans	71	0	1	15	54	0	1	99%
Pad-Mount Switchgears	25	0	0	8	1	16	0	100%
OH Conductors (m)	498,641	14,542	544	61,296	80,894	273,172	68,194	96%
UG Cables (m)	161,319	622	3,082	32,397	54,471	70,647	100	100%
SCADA Switches	18	0	0	15	0	3	0	100%
Pole-Mount Reclosers	11	0	0	0	0	11	0	100%
Station Assets								
Power Transformers	16	0	0	2	5	9	0	100%
Air Circuit Breakers	8	0	0	0	0	8	0	100%
Vacuum Circuit Breakers	25	0	0	0	0	25	0	100%
Metal-Clad Switchgears	12	0	0	3	4	5	0	100%
Pad-Mount Reclosers	14	0	0	0	0	14	0	100%

Table 5.3-7: Asset Categories, HI Distribution, and DAI

The DAI is generally complete for WHESC's asset categories. For wood poles, WHESC started using Polux testing in 2022 which is scheduled on a five year cycle. Prior inspection data for wood poles was gathered using visual inspection along with sound and bore techniques. Polux test result data is superior to previously employed inspection and test methodologies, providing a more accurate depiction of asset health. Based on this, the 2023 ACA process for wood poles extrapolated the Polux test results across the balance of the population using ten-year age bands. By 2026, the DAI for wood poles will approach 100%.

The HI distribution for the WHESC's asset categories is summarized in Figure 5.3-5, below.

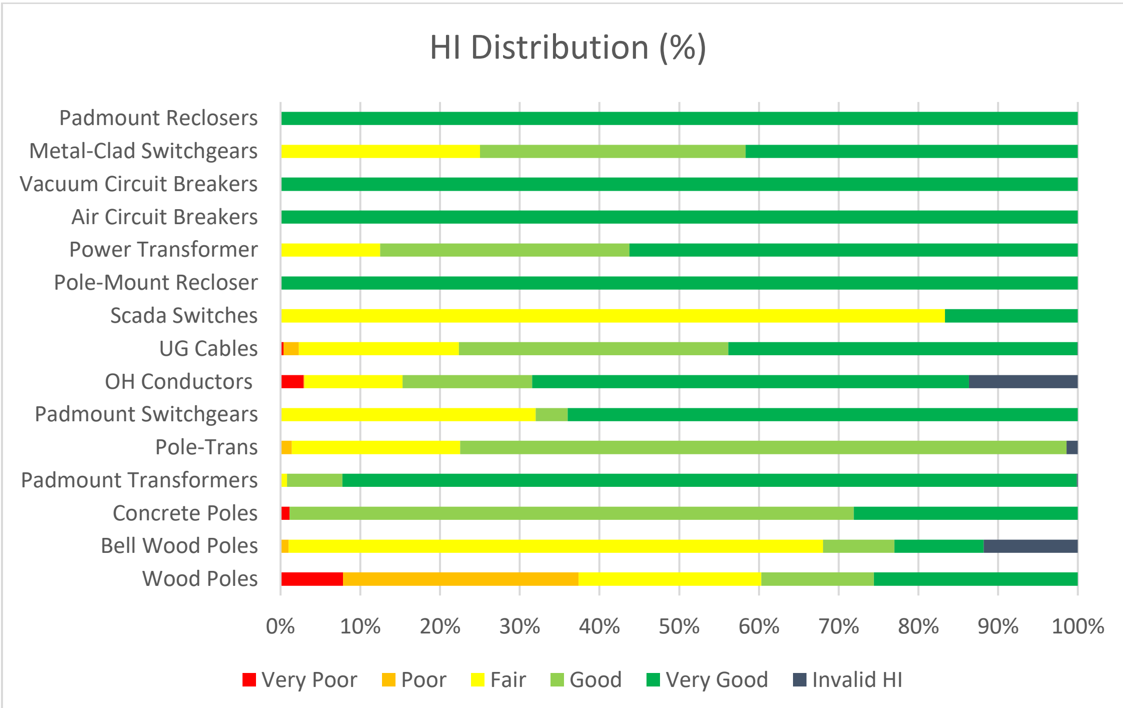


Figure 5.3-5: HI Distribution

Figure 5.3-5 indicates that wood poles, OH conductors, and UG cables have the highest percentage of assets in poor condition (See Section 5.3.2.2 for details). These health indices tie directly to capital investments in the system renewal category aimed at asset replacement.

For additional context regarding the state of WHESC's asset population, Table 5.3-8 indicates the age distribution for each category.

Asset Category	Population	TUL (Years)	Age Distribution					
			0 – 10 Years	11– 20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
Wood Poles	7527	45	1342	938	1164	466	3591	26
Bell Wood Poles	795	45	43	20	35	62	609	26
Concrete Poles	89	60	0	5	2	18	64	0
Pad-Mount Transformers	853	40	336	202	173	101	41	0
Pole-Trans	71	40	0	0	0	8	63	0
Pad-Mount Switchgears	25	30	13	4	8	0	0	0
OH Conductors	498,641	60	87,444	69,536	94,085	26,264	198,434	22,879
UG Cables	161,319	30	59,640	39,224	35,341	15,978	11,036	100

Asset Category	Population	TUL (Years)	Age Distribution					
			0 – 10 Years	11– 20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
SCADA Switches	18	20	0	3	15	0	0	0
Pole-Mount Reclosers	11	20	11	0	0	0	0	0
Power Transformers	16	45	8	3	2	1	2	0
Air Circuit Breakers	8	45	0	0	0	0	8	0
Vacuum Circuit Breakers	25	45	4	5	16	0	0	0
Metal-Clad Switchgears	12	40	1	3	5	0	3	0
Pad-Mount Reclosers	14	30	12	2	0	0	0	0

Table 5.3-8: Asset Age Distribution

The balance of this section summarizes the ACA findings of significance for WHESC's asset categories. For a complete summary of ACA findings, the full report is included in Appendix 5-H.

5.3.2.2.1 Wood Poles

WHESC owns and maintains 7,527 wood poles on its distribution system. Figure 5.3-6 illustrates the HI results for the population. Approximately 37% of wood poles have a health index of poor or very poor. Figure 5.3-7 indicates the percentage of wood poles past the asset's typical useful life (TUL). Approximately 44% of wood poles are categorized as being past TUL.

As indicated in Table 5.3-8, the TUL for wood poles used in the ACA aligns with Kinectrics' Asset Depreciation Study for the OEB, dated July 8th, 2010. In WHESC's experience, wood poles can remain in service past the TUL, dependent on the species and treatment type. This is the reason the ACA relies heavily on the pole test result. In Section 5.3.3.2.4, the pole testing and inspection program is described in conjunction with WHESC's prioritization of pole replacements to manage risk.

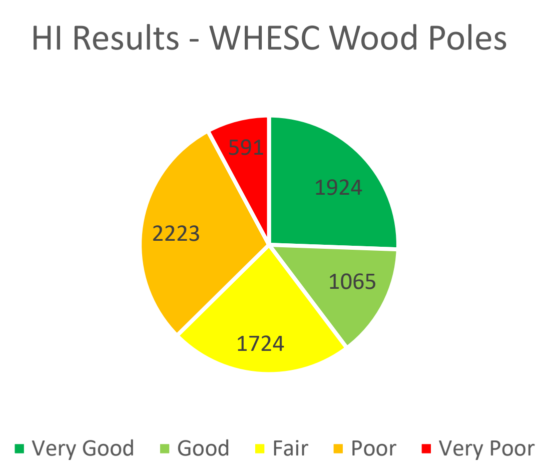
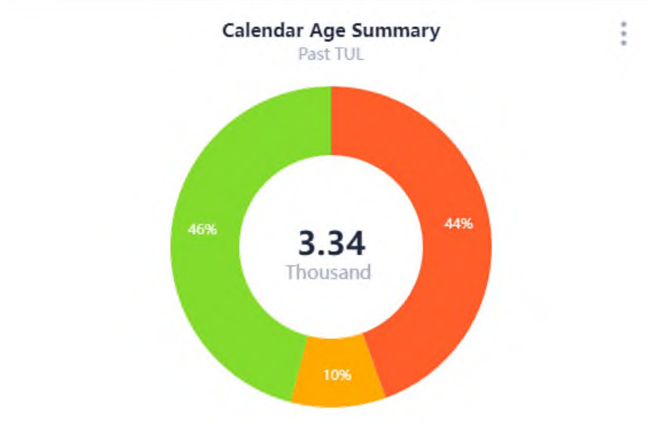


Figure 5.3-6: Wood Pole HI Results



	Past TUL	3.34K
	Approaching TUL	720
	Not Near TUL	3.44K
	Total	7.50K

Figure 5.3-7: Wood Pole Age Demographic Summary

WHESC also monitors the HI of wood poles owned by Bell Canada. Although these pole assets are not owned or maintained by WHESC, they support distribution assets. WHESC must ensure that the pole owner maintains the integrity of the asset sufficiently to manage overall distribution system performance. From the population of 769 poles, only eight are classified with an HI of poor or very poor with 579 of these poles classified as past their TUL.

5.3.2.2.2 Ground Mounted Transformers

WHESC maintains 852 pad-mounted transformers. Figure 5.3-8 illustrates the HI results for the pad-mounted transformer population. None are in poor or very poor condition. Figure 5.3-9 indicates the percentage of pad-mounted transformers past the asset's TUL. Approximately 5% of these transformers are categorized as being past TUL, however, based on the HI results are suitable to remain in service over the forecast period.

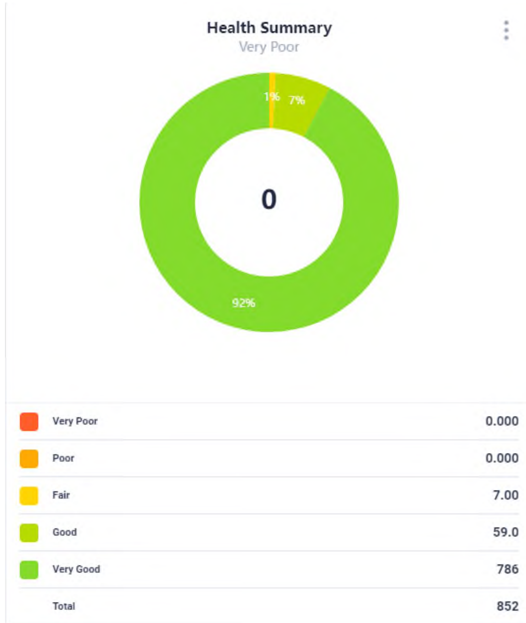


Figure 5.3-8: Pad-mounted Transformer HI Results

Figure 5.3-9: Pad-mounted Transformer Age Demographic Summary

WHESC's distribution system also contains 70 "pole-trans" distribution transformers. Figure 5.3-10 illustrates the HI results for the pole-trans population. During the historical period, capital expenditures have focused on the elimination of pole-trans transformers in conjunction with cable replacements where required based on asset condition. Of the 70 that remain, only one pole-trans has a HI categorized as poor. Figure 5.3-11 indicates the percentage of pole-trans transformers past the asset's TUL. Approximately 89% of pole trans are categorized as being past TUL. Replacement components are no longer manufactured for these devices. WHESC relies on legacy components remaining in inventory to recover from asset failure. WHESC's UG renewal investments in the forecast period target units with a fair or poor HI.

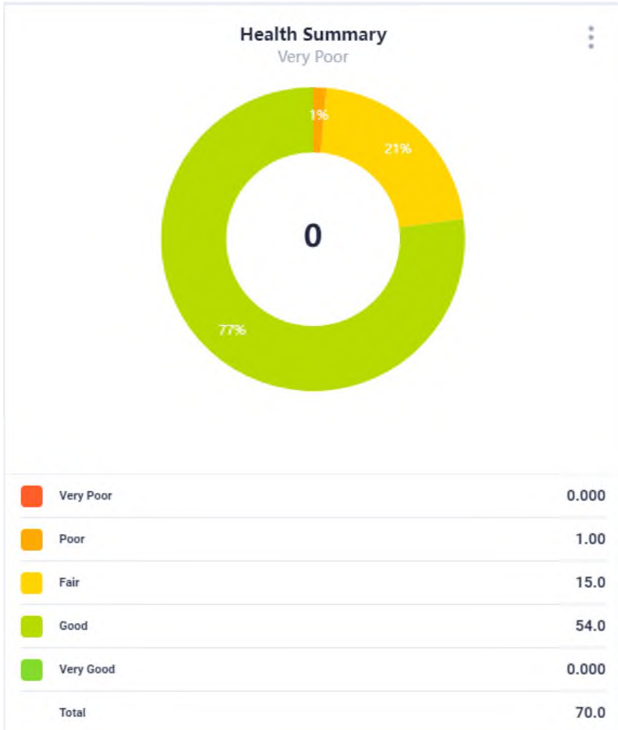


Figure 5.3-10: Pole-Trans HI Results

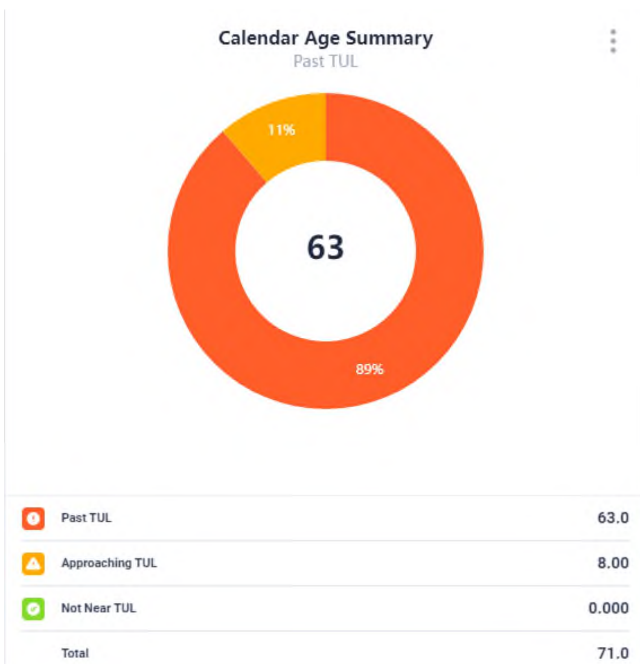


Figure 5.3-11: Pole-Trans Age Demographic Summary

5.3.2.2.3 Pad Mounted Switchgear

WHESC currently maintains 25 pad-mounted switchgear within its service area. Figure 5.3-12 illustrates the HI results for the pad-mounted switchgear population. None are in poor or very poor condition. Figure 5.3-13 indicates the percentage of pad-mounted switchgear units past the asset's TUL. None of the switchgear are categorized as being past TUL.

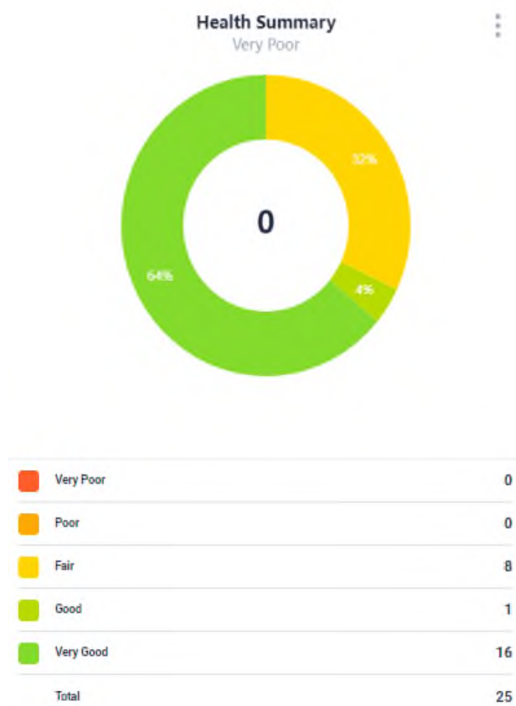


Figure 5.3-12: Pad-Mounted Switchgear HI Results

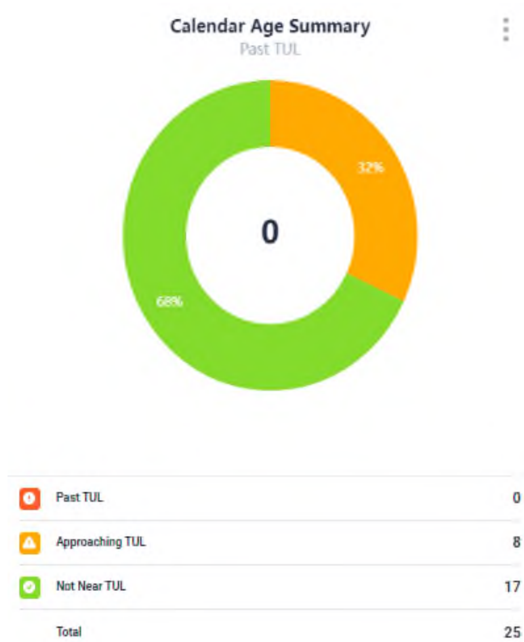


Figure 5.3-13: Pad-Mounted Switchgear Age Demographic Summary

As indicated above, eight units are approaching TUL. Most of the population consists of air-insulated components susceptible to tracking and insulator failure. As these units are generally deployed in main feeder locations, the failure mode leads to long duration outages affecting a significant number of customers. WHESC has established a program to replace units of this design with solid-dielectric or gas-insulated switchgear to mitigate switchgear failures.

5.3.2.2.4 Overhead Conductors

WHESC owns approximately 499 km of overhead conductors within its service area. Figure 5.3-14 illustrates the HI results for the overhead conductor population. Approximately 15 km of overhead conductor is in poor or very poor condition. Figure 5.3-15 indicates the percentage of overhead conductor past the asset's TUL. Just under 90 km of conductor is categorized as being past TUL.

Figure 5.3-14: Overhead Conductor HI Results

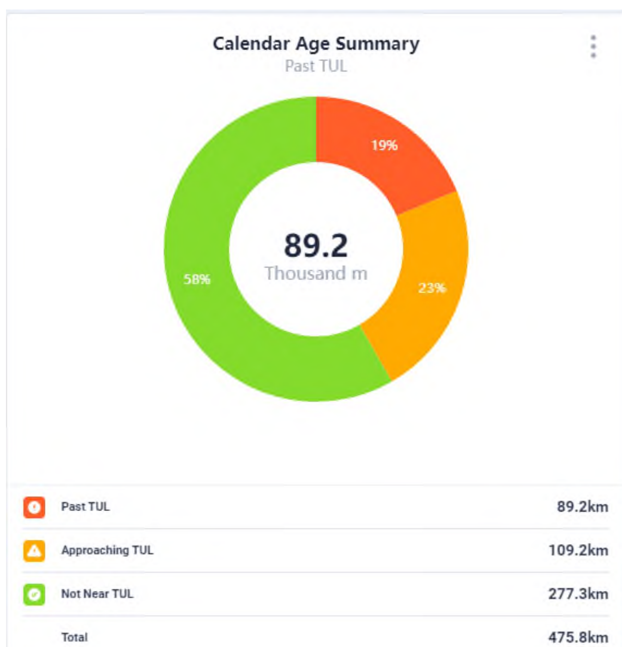


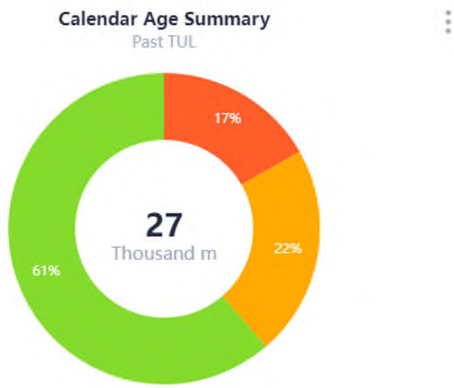
Figure 5.3-15: Overhead Conductor Age Demographic Summary

The population with a very poor HI consists of conductor classified as "restricted". The industry generally classifies conductor sizes smaller than 6 AWG CU or 4 AWG ACSR (aluminum conductor steel reinforced) as restricted since it is highly unsafe to manipulate the conductor tension while in an energized state. WHESC will only work in proximity to this type of conductor when de-energized, resulting in the need for planned outages affecting a significant number of customers. For the overhead rebuilds contemplated in the forecast period, many target elimination of this conductor type along with replacing deteriorated wood pole assets.

5.3.2.2.5 Underground Cables

WHESC owns approximately 161 km of underground cables within its service area. Figure 5.3-16 illustrates the HI results for the underground cable population. Approximately 3.7 km of underground cable is in poor or very poor condition. Figure 5.3-17 indicates the percentage of underground cable past the asset's TUL. 27-km of underground cable is categorized as being past TUL. WHESC's forecast system renewal investments focuses on replacement cable with a poor or very poor HI.

Figure 5.3-16: Underground Cable HI Results



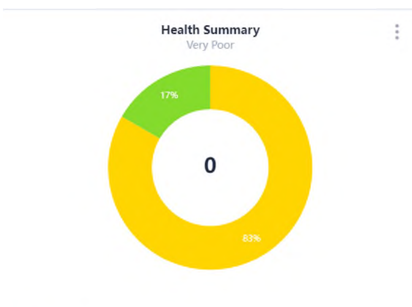
	Past TUL	27.0km
	Approaching TUL	35.3km
	Not Near TUL	98.9km
	Total	161.2km

Figure 5.3-17: Underground Cable Age Demographic Summary

5.3.2.2.6 SCADA Switches and Reclosers

Legacy SCADA Switches

WHESC owns 18 pole-mounted SCADA switches on the 27.6 kV distribution system. Figure 5.3-18 illustrates the HI results for the SCADA switch population. None of these devices are in poor or very poor condition. However, 15 of these devices are categorized as being past TUL as illustrated in Figure 5.3-19.



	Very Poor	0.000
	Poor	0.000
	Fair	15.0
	Good	0.000
	Very Good	3.00
	Total	18.0

Figure 5.3-18: SCADA Switch HI Results

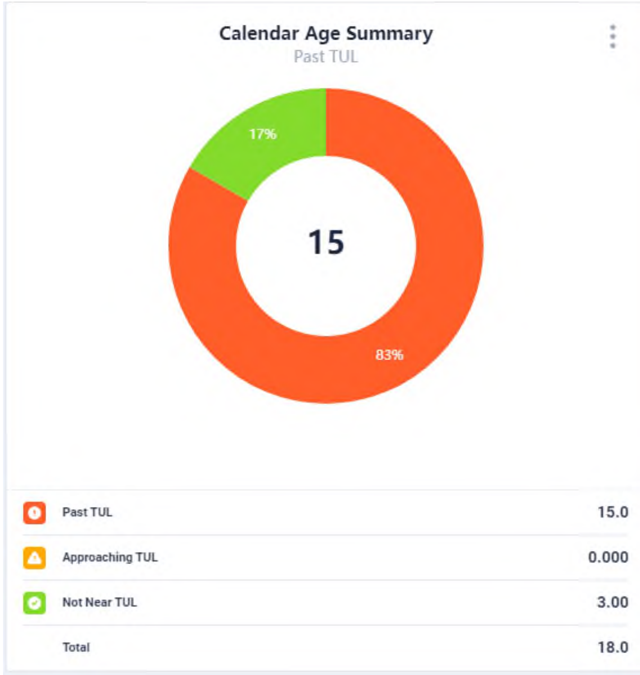


Figure 5.3-19: SCADA Switch Age Demographic Summary

WHESC has refurbished approximately half of the SCADA switch fleet past TUL and incorporated new control systems. The planned system service investments in the forecast period include the replacement of five legacy SCADA switches based on TUL and reduction of operating expenses associated with legacy communication systems. This results in approximately a $15K reduction in operating expenses annually.

Modern SCADA Reclosers

WHESC owns 11 pole-mounted reclosers on the 27.6 kV distribution system. These devices can be configured to operate as a recloser, sectionalizer, or an intelligent switch. The devices are deployed on the 27.6 kV system as part of WHESC's grid modernization strategy and will replace legacy SCADA switches when the device condition is deteriorated. Figure 5.3-20 illustrates the HI results for the recloser population. None of these devices are in poor or very poor condition. Figure 5.3-21 indicates that none of these devices are near TUL.

Figure 5.3-20: Recloser HI Results

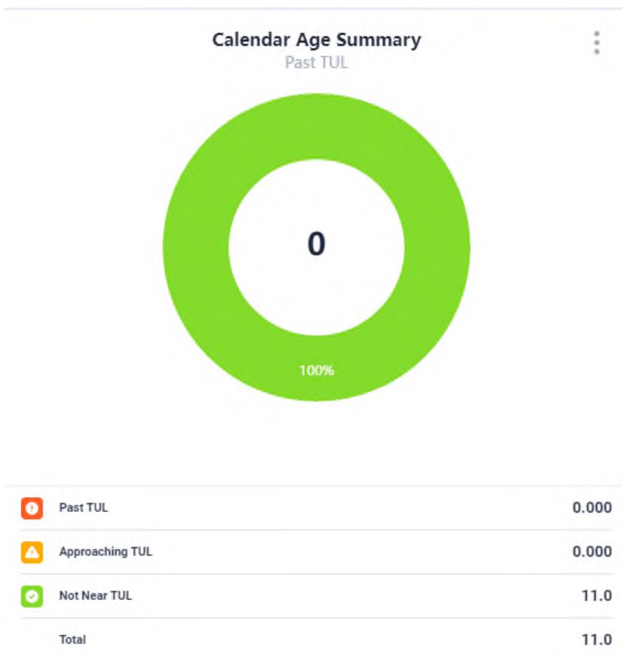


Figure 5.3-21: Recloser Age Demographic Summary

WHESC's fleet of modern SCADA reclosers were installed in the historical period and are not subject to proactive replacement in the forecast period.

5.3.2.2.7 Station Assets

The latest ACA included WHESC owned substation assets. Power transformers, circuit breakers, metal-clad switchgear, and station circuit reclosers are the station assets that were assessed. Table 5.3-9 provides a summary of the HI findings.

Station	PTX 1	PTX 2	Circuit Breakers	4.16 kV Metal-Clad SWGR	27.6 kV Metal-Clad SWGR	Pad-Mount Reclosers	Average DAI
MS 1	63%	N/A	88%	82%	89%	N/A	100%
MS 2	83%	N/A	N/A	N/A	N/A	93%	100%
MS 3	100%	93%	N/A	N/A	N/A	100%	100%
MS 4	86%	N/A	96%	89%	57%	N/A	100%
MS 5	87%	88%	96%	82%	50%	N/A	100%
MS 6	73%	N/A	94%	80%	N/A	N/A	100%
MS 7	85%	N/A	100%	100%	68%	N/A	100%
MS 8	93%	N/A	N/A	N/A	N/A	100%	100%
MS 9	93%	N/A	N/A	N/A	N/A	100%	100%
MS 10	83%	N/A	86%	75%	95%	N/A	100%
MS 11	95%	N/A	N/A	N/A	N/A	100%	100%
MS 12	73%	60%	88%	89%	N/A	N/A	100%
MS 14	74%	N/A	N/A	N/A	N/A	100%	100%

Table 5.3-9: Station HI Summary

A summary of station asset age demographic is provided in Table 5.3-10, below.

Station	PTX 1	PTX 2	Circuit Breakers	4.16 kV Metal-Clad SWGR	27.6 kV Metal-Clad SWGR	Pad-Mount Reclosers
MS 1	29	N/A	29	29	24	N/A
MS 2	14	N/A	N/A	N/A	N/A	15
MS 3	1	1	N/A	N/A	N/A	1
MS 4	22	N/A	20	20	20	N/A
MS 5	46	1	27	27	27	N/A
MS 6	11	N/A	44	44	N/A	N/A
MS 7	59	N/A	7	7	59	N/A
MS 8	5	N/A	N/A	N/A	N/A	4
MS 9	4	N/A	N/A	N/A	N/A	3
MS 10	31	N/A	45	45	11	N/A
MS 11	7	N/A	N/A	N/A	N/A	1
MS 12	8	16	25	25	N/A	N/A
MS 14	6	N/A	N/A	N/A	N/A	6

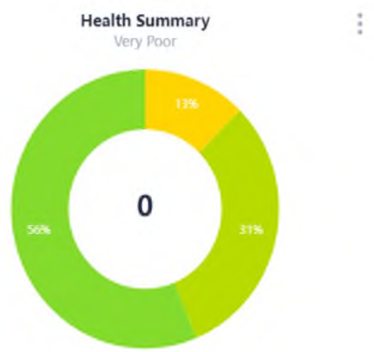
Table 5.3-10: Station Component Age Summary

Based on the HI results and age demographic presented in these tables, WHESC has planned replacement of the MS5 and MS7 power transformers and associated cable systems. These replacements result in a reduction in MS capacity based on load forecasts associated with each substation. The 27.6kV metal-clad switchgear at each station will be eliminated in the process. WHESC's new installation standard incorporates primary isolation switches into the transformer.

The transformer at MS1 has conditional issues that are being mitigated though preventative maintenance by performing oil re-conditioning.

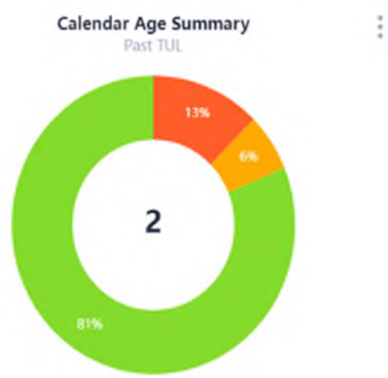
Power Transformers

WHESC owns 16 power transformers deployed within municipal substations. Figure 5.3-22 illustrates the HI results for the power transformer fleet. There are two with a health index categorized as fair. None are in poor or very poor condition. Figure 5.3-23 indicates that two of these units are past TUL.



Very Poor	0
Poor	0
Fair	2
Good	5
Very Good	9
Total	16

Figure 5.3-22: Power Transformer HI Results



Past TUL	2
Approaching TUL	1
Not Near TUL	13
Total	16

Figure 5.3-23: Power Transformer Age Demographic Summary

The two units with an HI in fair condition are the single transformers at MS1 and MS12. The unit at MS1 is having asset health issues mitigated through transformer oil re-conditioning in the bridge year. The unit at MS12 will be monitored throughout the forecast period based on its purpose as a back-up unit for the substation. As mentioned above, the power transformers and MS5 and MS7 are scheduled for replacement in the forecast period based on being in service past the TUL.

Circuit Breakers

WHESC maintains two types of circuit breakers within municipal substations. These are air and vacuum type circuit breakers.

WHESC has 8 air circuit breakers deployed within municipal substations. Figure 5.3-24 illustrates the HI results for air circuit breakers. All have a health index categorized as very good. Figure 5.3-25 indicates that all of these breakers are approaching TUL.

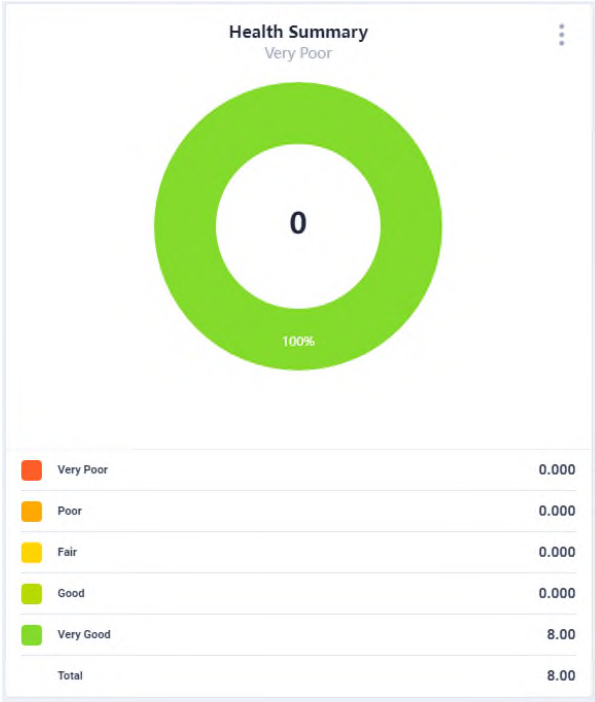


Figure 5.3-24: Air Circuit Breaker HI Results

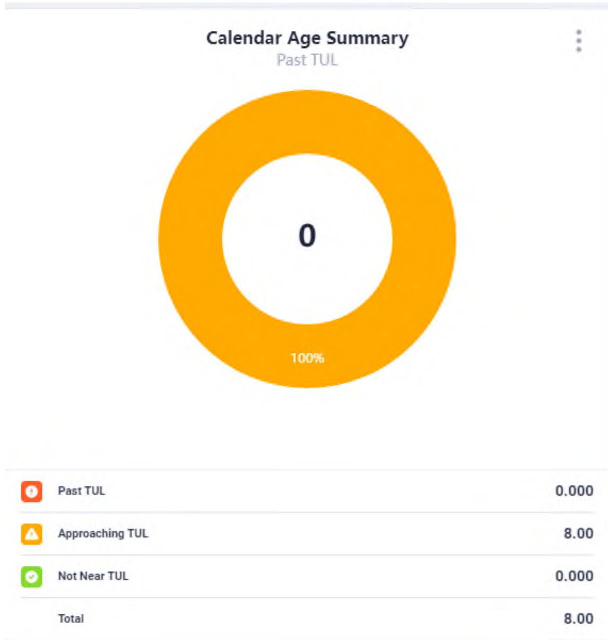


Figure 5.3-25: Air Circuit Breaker Age Demographic Summary

WHESC performed preventative maintenance on the fleet of air circuit breakers in the historical period and plans to continue this in the forecast period. The devices will be monitored through substation inspections (see Section 5.3.3.2.1) as the service life of these are extended.

WHESC also has 25 vacuum circuit breakers deployed within municipal substations. Figure 5.3-26 illustrates the HI results for vacuum circuit breakers. All have a health index categorized as very good. Figure 5.3-27 indicates that none of these breakers are approaching TUL.

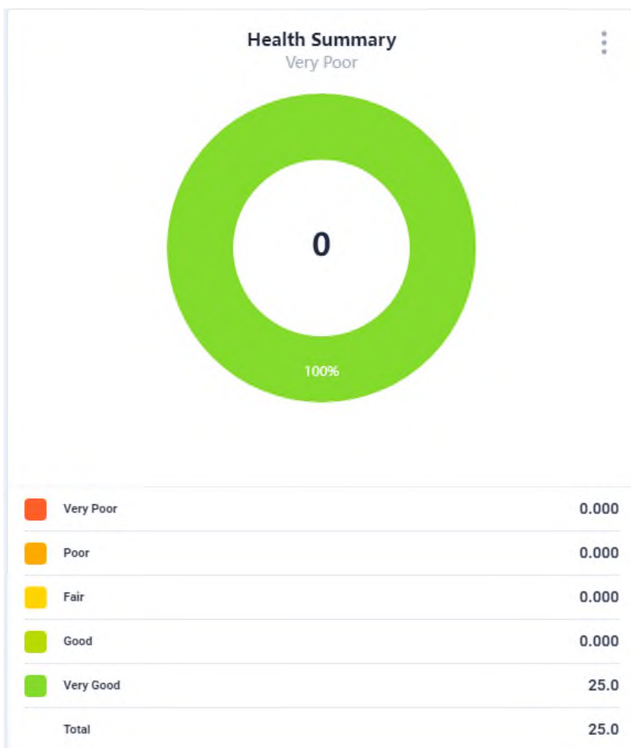


Figure 5.3-26: Vacuum Circuit Breaker HI Results

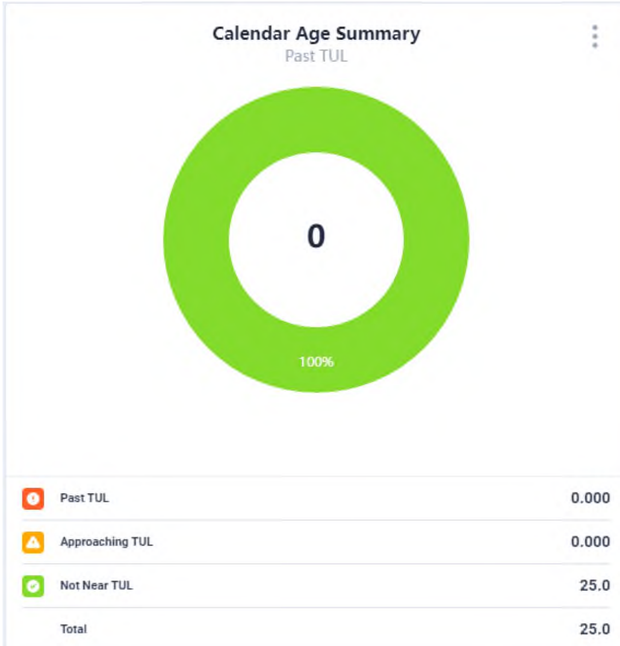


Figure 5.3-27: Vacuum Circuit Breaker Age Demographic Summary

Based on asset HI, WHESC has no planned replacement of vacuum circuit breakers in the forecast period.

Metal-Clad Switchgear and Station Reclosers

The stabilization of WHESC's substations in the historical period resulted in two styles of high-level station designs on either the 27.6kV or 4.16kV system. One that encompasses metal-clad switchgear; the other a pad-mounted recloser lineup.

WHESC has 12 instances of metal-clad switchgear deployed within its substations. Figure 5.3-28 illustrates the HI results for metal-clad switchgear. None of these have a health index categorized as poor or very poor. Figure 5.3-29 indicates that three of these metal-clad switchgear installations are past TUL.

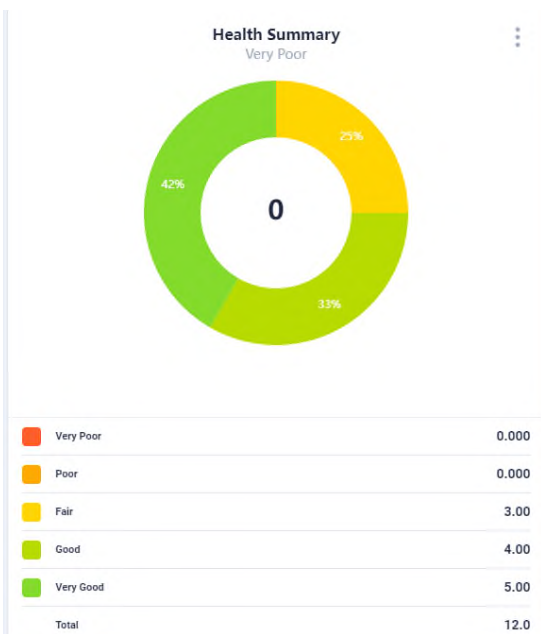


Figure 5.3-28: Metal-Clad Switchgear HI Results

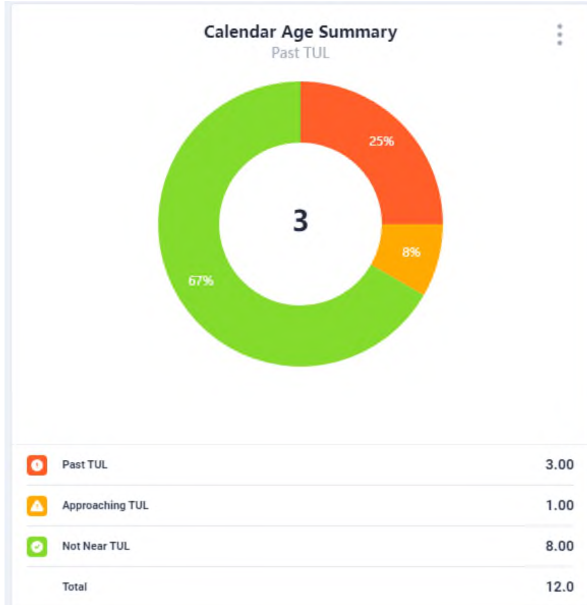


Figure 5.3-29: Metal-Clad Switchgear Age Demographic Summary

As mentioned above, two of the metal-clad switchgear in poor condition will be eliminated in the forecast period. The remainder will have conditional issues mitigated through preventative maintenance.

WHESC also has 14 pad-mounted vacuum reclosers deployed within municipal substations. Figure 5.3-30 illustrates the HI results for pad-mounted reclosers. All have a health index categorized as very good. Figure 5.3-31 indicates that none of these pad-mounted reclosers are approaching TUL.

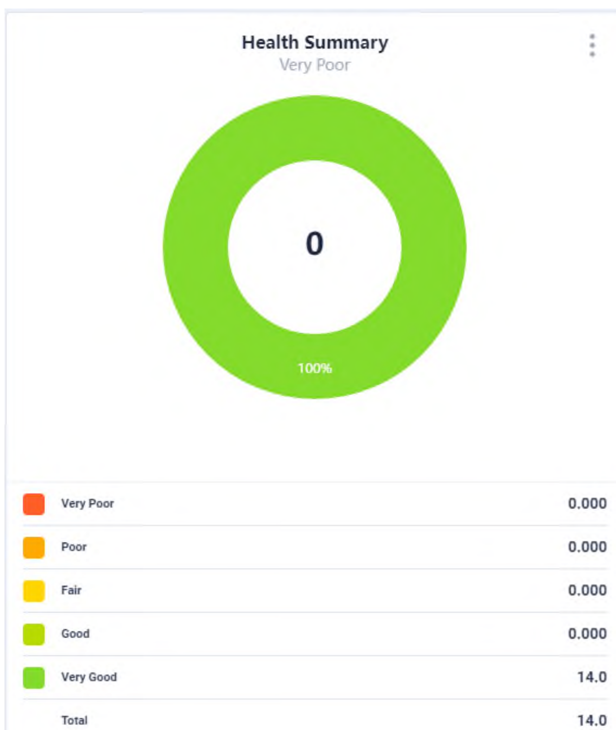


Figure 5.3-30: Pad-mounted Recloser HI Results

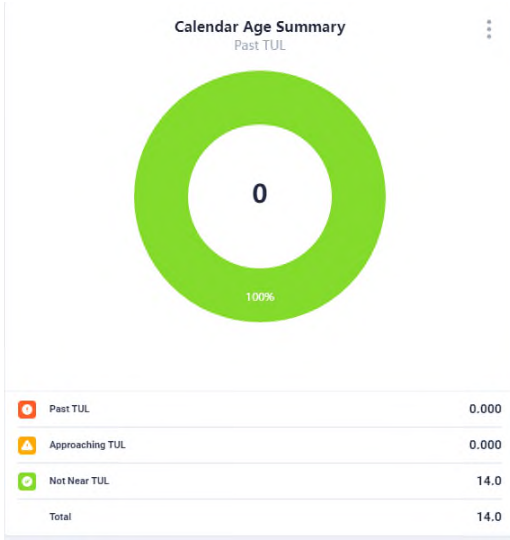


Figure 5.3-31: Pad-mounted Recloser Age Demographic Summary

Based on asset HI, WHESC has no planned replacement of pad-mounted reclosers in the forecast period.

5.3.2.2.8 Fleet / Rolling Stock

In 2023, WHESC conducted a fleet assessment. The fleet assessment report is included in Appendix 5-I. Included in the assessment were the following asset classes:

- Pick-up Trucks
- Cargo Vans
- Mini Vans
- Bucket Trucks
- Digger Trucks
- Trailers
- Wheel Loaders
- Forklift Trucks
- Backyard Diggers

Table 5.3-12 provides a summary of the assessment results. Table 5.3-11, shown below identifies TUL for WHESC fleet vehicles, where applicable. Generally, light duty vehicles have a TUL of 10 years, large trucks have a TUL of 15 years.

Fleet Asset	Class	Typical Useful Life (Years)	Mileage (km)	Engine Hours
Pick-up Trucks	LV	10	180,000	N/A
Mini Van	LV	10	120,000	N/A
Cargo Van	LV	10	140,000	N/A
Diggers	HV	15	195,000	12,000
Bucket Trucks	HV	15	210,000	12,000
Trailers	TR	20	N/A	N/A
Wheel Loader	OT	N/A	N/A	12,000
Forklift Truck	OT	N/A	N/A	10,000
Backyard Digger	OT	N/A	N/A	12,000

Table 5.3-11: Typical TUL for WHESC Fleet / Rolling Stock

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
LV-1	2011 GMC Canyon	Pickup Truck	0%	45%	Poor
LV-3	2010 GMC Sierra	Pickup Truck	0%	40%	Poor
LV-24	2018 Ford F-250	Pickup Truck	40%	85%	Very Good
LV-36	2017 GMC Sierra	Pickup Truck	30%	80%	Good
LV-37	2016 Ford F-150	Pickup Truck	20%	73%	Good
LV-42	2020 Chevrolet Silverado	Pickup Truck	60%	78%	Good
LV-44	2019 Ford Transit 150	Cargo Van	50%	85%	Very Good
LV-51	2022 Ford F-150 P/U	Pickup Truck	80%	90%	Very Good
LV-52	2022 Ford F-150 P/U	Pickup Truck	80%	90%	Very Good
LV-53	2011 GMC Sierra P/U	Pickup Truck	0%	33%	Poor
LV-54	2016 Ford F-150 P/U	Pickup Truck	20%	80%	Good
LV-60	2015 Nissan NV200	Mini Van	10%	73%	Good
HV-4	2010 Freightliner M2 106	Bucket Truck	0%	58%	Fair
HV-9	2016 Freightliner M2 106	Bucket Truck	47%	71%	Good
HV-11	2012 Freightliner M2 106	Bucket Truck	20%	64%	Fair
HV-15	2009 International 4400	Bucket Truck	0%	55%	Fair
HV-18	2019 Freightliner M2 108	Digger Truck	67%	90%	Very Good
HV-31	2017 Freightliner	Digger Truck	53%	86%	Very Good
HV-46	2021 Freightliner M2 106	Bucket Truck	80%	90%	Very Good
HV-55	2013 Freightliner	Bucket Truck	27%	68%	Fair
TR-6	2017 Dump Trailer	Trailer	65%	78%	Good
TR-27	2024 Dump Trailer	Trailer	100%	90%	Very Good
TR-29	2019 Sauber Reel Trailer	Trailer	75%	90%	Very Good
TR-33	1991 Nicholls Trailer	Trailer	0%	20%	Very Poor
TR-35	1982 Lge. Reel Trailer	Trailer	0%	20%	Very Poor
TR-56	2014 Brooks PTB	Trailer	50%	78%	Good
TR-58	2009 H&H Trailer	Trailer	25%	60%	Fair
TR-59	2015 Nichols Trailer	Trailer	55%	78%	Good
OT-32	2005 New Holland	Wheel Loader	55%	63%	Fair
OT-43	2002 Hyster Lift Truck	Fork Lift Truck	93%	85%	Very Good
OT-57	2005 Altec DB35	Backyard Digger	92%	85%	Very Good

Table 5.3-12: Fleet HI Summary

The HI values associated with WHESC fleet categories are shown in Figure 5.3-32. WHESC has three light duty vehicles in poor condition. There are three vehicles with zero remaining life and six that will reach the TUL within the forecast period. WHESC has included the replacement of a light duty vehicle in every year of the five year forecast period. This level of investment is expected to assist WHESC in reach sustainment levels of asset renewal in its light duty fleet.

For heavy duty vehicles, none are in poor or very poor condition. There are two vehicles with zero remaining life and two that will reach the TUL in the forecast period. WHESC has planned for the replacement of two bucket trucks at TUL and the reduction in the heavy duty fleet by one unit.

Table 5.4-15 summarizes WHESC's planned fleet replacements.

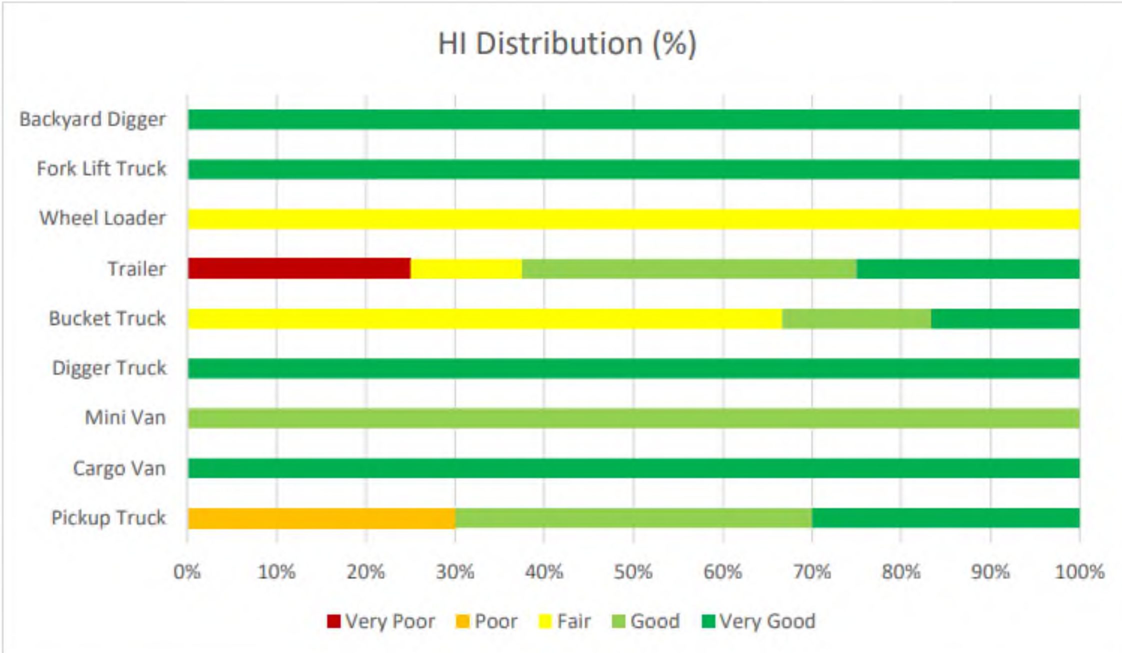


Figure 5.3-32 Fleet / Rolling Stock HI Results

5.3.2.3 Transmission or High Voltage Assets

WHESC does not own any transmission or high voltage assets > 50 kV.

5.3.2.4 Host & Embedded Distributors

WHESC is not a host or embedded distributor. WHESC receives electricity directly from a HONI TS. None of WHESC's feeders are classified as a hybrid or shared feeders. All nine feeders supplied from Crowland TS service only WHESC load and DER customers.

5.3.3 Asset Lifecycle Optimization Policies and Practices

WHESC's asset management strategy is to maximize the service life of distribution assets at the lowest total lifecycle cost of ownership. WHESC's asset management process strikes a balance between asset refurbishment and replacement to minimize both cost and the impact of failure risk.

5.3.3.1 Asset Replacement and Refurbishment Policy

WHESC leverages the results of cyclical asset inspection programs to determine failure risk. Through analysis of inspection data, WHESC prioritizes specific asset replacement and refurbishment needs based on this risk. Alternatives to mitigate the affects of asset failure are identified. The choice on the most appropriate alternative is based on alignment with WHESC's strategic objectives and corporate goals.

WHESC considers future needs when selecting alternatives to manage assets. Data is analyzed to understand current asset utilization, customer preferences, future capacity requirements, and system resiliency. As an example, in the case of substation assets, WHESC considers historical loading, load transfer alternatives, future needs stemming from growth and fuel switching, etc. to assess alternatives. In some cases, as demonstrated in the historical period with power transformers, WHESC may choose to extend an asset beyond it's TUL to mitigate cost impact to customers. WHESC must always ensure that deploying such alternatives does not present unacceptable risk to system performance associated with asset failure.

For system renewal-based investments, WHESC organizes proposed projects into three high level categories of investments: substations, overhead rebuilds/conversion, and underground rebuilds. For substations, it is important to note that WHESC's planning process is designed to minimize the impacts of capacity needs on the 4.16 kV system. New connections are established on the 28 kV system as a first choice and there are rare circumstances where supply is established from the 4.16 kV system. When assessing asset management alternatives, conversion of load to the 28 kV system is always considered. WHESC performs rigid inspection and maintenance on its fleet of municipal substations annually to extend the life of these assets to the greatest extent possible.

On WHESC's overhead systems, asset risk is generally mitigated through replacement programs. Unlike substations that typically require a large initial capital investment, the asset classes in this category have a small initial capital investment when viewed individually. Few of the individual asset components on overhead systems present the opportunity for refurbishment.

The underground system does present opportunities for refurbishment/renewal optimization. Typically the asset components in this category have a high initial deployment cost, such as large capacity pad-mounted transformers and switchgear and have components that can be refurbished or replaced. WHESC through its cyclical inspection programs (oil sampling, infrared scanning, etc.), will refurbish equipment enclosures, perform de-contamination of insulating components, maintain insulating fluid, etc. where the mitigation produces the lowest total lifecycle cost.

Assets in the general plant category, specifically fleet / rolling stock, are subject to refurbishment in lieu of replacement to manage total lifecycle cost through the asset's TUL. Historically, WHESC has performed heavy vehicle refurbishment to maintain or extend the life of the asset in lieu of replacement.

WHESC uses different strategies to manage a specific asset type based on the impact of asset failure risk. Table 5.3-13 summarizes WHESC's approach for each asset type:

Asset Type	Replacement Strategy
Poles	**Proactive**
Pad-mounted Transformers	**Proactive**
Pole-Trans	**Proactive**
Pole-mounted Transformers	**Reactive**
Pad-mounted Switchgear	**Proactive**
Overhead Conductor	**Proactive/Reactive**
Underground Cable	**Proactive/Reactive**
SCADA Switches	**Proactive**
Pole-Mounted Reclosers	**Proactive**
Power Transformers	**Proactive**
Circuit Breakers	**Proactive**
Metal-Clad Switchgear	**Proactive**
Pad-mounted Reclosers	**Proactive**
Fleet / Rolling Stock	**Proactive**

Table 5.3-13: Asset Replacement Strategy

Pole-mounted transformers are subject to reactive replacement based on the relatively low unit replacement cost and a small impact on system reliability of the overall distribution system due to failure. WHESC does, however, monitor the utilization of these assets via its SmartMap system. Units with a trend in overloading are prioritized for proactive replacement. WHESC also uses SmartMap to monitor voltage performance and will make localized adjustments at a transformer to mitigate out of tolerance conditions.

An example of a potential transformer overload is shown in Figure 5.3-33.

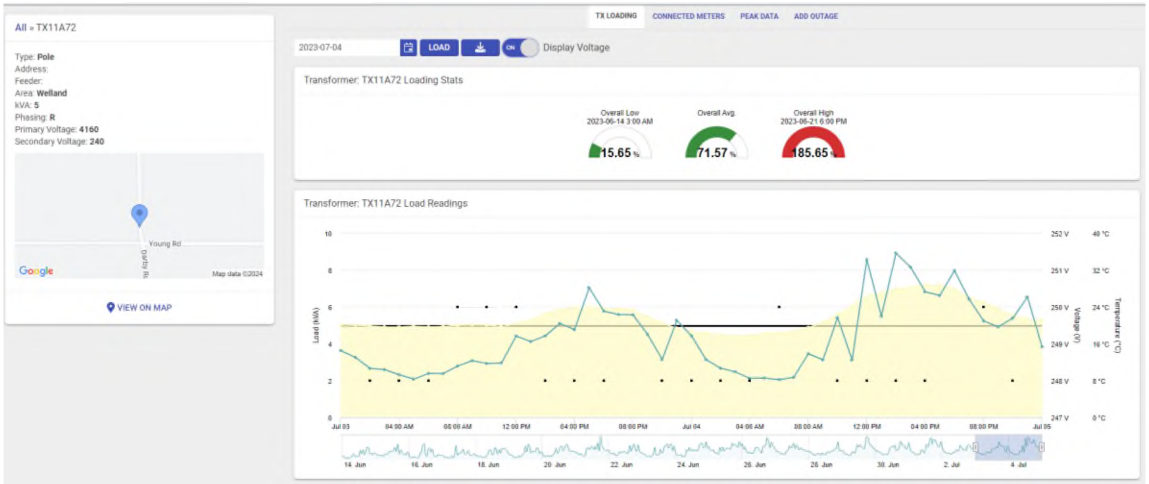


Figure 5.3-33: Transformer Overloading Example

Overhead conductor classified as restricted is proactively managed due to the inherent health and safety risk associated with its performance. The balance of the overhead conductor on WHESC's system is generally replaced reactively.

Underground cable may be managed reactively when the asset is past TUL, depending on the impact of failure on overall system reliability. WHESC's underground distribution is configured with redundancy, allowing for a faulted cable section to be isolated while maintaining supply to customers.

5.3.3.2 Description of Maintenance and Inspection Practices

WHESC plans maintenance and inspection programs on an annual basis. Budgets for maintenance and inspection activities are informed by historical expenditures for refurbishing the various asset types, as well as historical inspection program costs. WHESC employs predictive, preventative, and condition-based maintenance practices to ensure assets are operating as intended and risk associated with failure is minimized or otherwise monitored. These practices are summarized as follows:

Predictive Maintenance

These are activities that detect changes in the physical condition of equipment (indications of failure) in order to execute appropriate condition-based maintenance or capital investment. Predictive maintenance activities include thermographic infrared inspections, transformer dissolved gas analysis, comprehensive pole inspections, and substation equipment testing. All fleet / rolling stock assets are subject to annual safety inspections. Additionally, all aerial devices undergo annual dielectric testing. Facility backup systems are tested monthly to verify functional integrity.

Preventative Maintenance

Preventative maintenance activities are performed at pre-defined intervals to reduce the probability of asset failure. These activities include vegetation management, visual asset inspections, and substation equipment maintenance.

Condition-Based Maintenance

These activities are performed after indication of impending failure or degradation in performance or condition of an asset. Condition-based maintenance serves to reduce the possibility of breakdowns and reduce deviations from optimum asset performance. Condition-based maintenance involves repair and/or replacement of defective components.

WHESC's inspection and maintenance programs are designed to follow the guidelines set forth in the DSC, Appendix C. The results of cyclical inspection programs provide the foundational data for ACAs. This data is critical to the prioritization of investments and managing system renewal expenditures.

The balance of this section summarizes the cyclical inspection and maintenance programs deployed by WHESC.

5.3.3.2.1 Municipal Substation Inspection and Maintenance

WHESC operates a fleet of 13 municipal substations within its service territory. Inspection and maintenance of equipment located within municipal substations occurs monthly in alignment with DSC, Appendix C guidelines. Throughout the historical period, protection systems were refurbished or upgraded at the majority of WHESC's substations. At present, all the substations are of the type Outdoor Enclosed or Indoor Enclosed and WHESC is exceeding the inspection guidelines of the DSC, Appendix C.

Table 5.3-14 summarizes the specific inspection and/or maintenance activities associated with each asset type.

Asset Type	Inspection Activity	Inspection Points	Frequency
Power Transformers	Visual	Oil Temp	Monthly
		Winding Temp	
		Oil Level	
		Cooling System Function	
		Loss of Oil Evidence	
		Desiccant Condition	
		Enclosure/Tank Condition	
	Oil Analysis	Moisture Content	Annually
		Dissolved Gas Analysis	
		Di-Electric Strength	
	Infrared Scanning	Insulator / Termination Condition	Annually
	Electrical Testing	Insulation Resistance	Three Year Cycle
		Turns Ratio	
		Capacitance Test	
Circuit Breakers/Reclosers	Visual	Window / Physical Inspection	Monthly
	Function/Electrical Testing	Racking Mechanism	Three Year Cycle
		Contact Resistance	
		Insulation Resistance	
		Charing Motor	
		Anti-Pump Operation	
		Closing Coil Operation	
		Trip Coil Operations	
Switchgear	Visual	Physical Inspection	Monthly
	Infrared Scanning	Bus / Insulator / Termination Condition	Annually
	Electrical Testing	Insulation Resistance	Three Year Cycle
Protection Systems	Function/Electrical Testing	Relay Injection Testing	Three Year Cycle
		SCADA Controls	
Battery Systems	Visual	Terminals	Monthly
		Fluid Levels	
	Function/Electrical Testing	Load Test	Three Year Cycle
		Charging System	
Perimeter Containment	Visual	Fencing	Monthly
		Grounding	
		Security Devices	
		Lighting	

Table 5.3-14: Substation Inspection and Maintenance

Oil analysis is performed annually by a qualified contractor on each of the 16 power transformers in municipal substations. Results are reviewed to identify any immediate need for mitigation in addition with year over year trending analysis. Condition based maintenance may result from analysis of DGA results.

Infrared inspections are conducted on substation equipment annually by a qualified contractor. Any reported deficiencies are reviewed and typically mitigated by condition-based maintenance activities.

Function and electrical testing are completed by WHESC operations staff, qualified as substation electricians. Test results are captured in formal reports and abnormal results are typically mitigated by staff through maintenance activities scheduled in conjunction with equipment testing.

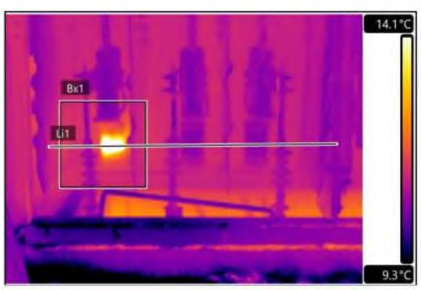
5.3.3.2.2 Pad-mounted Equipment Inspection

Pole-trans, pad-mounted transformers and switchgear are inspected on a two-year cycle as part of WHESC's thermographic infrared imaging program. During the inspection, equipment is imaged to identify temperature variances or "hot spots". Hot spots, representing deficiencies of the device or its peripheral attachments such as bushings are categorized as minor, intermediate, or severe. A severe finding represents a risk to health and safety, the environment, and / or reliability. In conjunction with the thermographic scan, the device is visually inspected to assess condition and any deficiencies. Deficiencies are identified and documented in WHESC's GIS for disposition and follow-up.

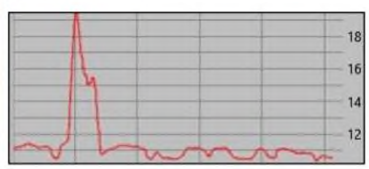
Deficiencies identified as severe or critical by WHESC qualified field staff are reported immediately for corrective action. Examples of critical deficiencies include missing locks / security provisions, or the potential for access to energized parts. Condition-based maintenance resulting from these deficiencies includes repair or replacement of the defective component or unit at the time of the inspection. Remediation activities are identified on the inspection record within the GIS.

An example of a reported infrared inspection result on pad-mounted equipment is shown in Figure 5.3-34.

Item #31



Object Emissivity	1.00
Object Distance	2.0 m
Atmospheric Temperature	9.0 °C
Relative humidity	64%



Location

PMH Location #**SG9**
Compartment 4
Near Thorald Road and Oakcrest Avenue
Behind *Shoppers Drug Mart*
WELLAND.

Description

Tracking/corona noted on red phase rear insulator.

Observation at 2023-10-10 10:17:00 AM

Fault Bx1 **19.5 °C** Ok Bx2 T.Rise... **10.5 °C** PRIORITY:

Figure 5.3-34: Sample Infrared Inspection Result Pad-mounted Equipment

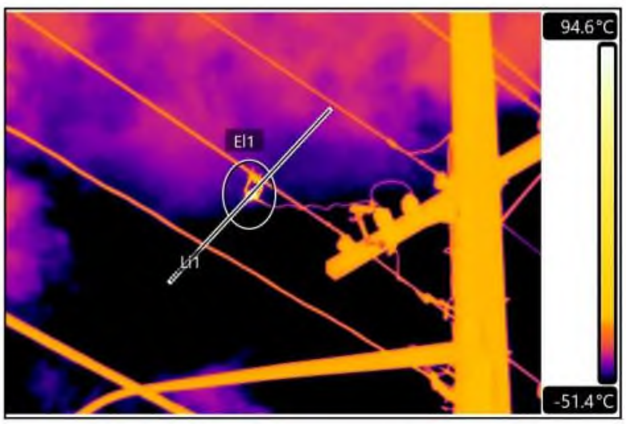
5.3.3.2.3 Overhead System Infrared Inspection

Overhead systems are inspected annually as part of WHESC's thermographic infrared imaging program. During the inspection, equipment is imaged to identify temperature variances or "hot spots". As was the case with pad-mounted equipment scanning, hot spots representing deficiencies of a device are categorized as minor, intermediate, or severe.

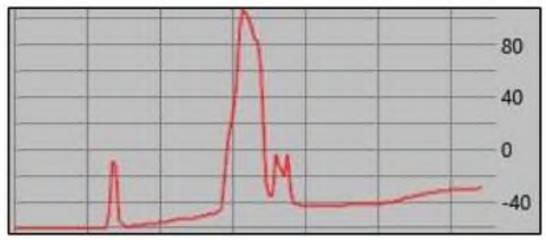
Deficiencies identified as severe are reported immediately for corrective action. Condition-based maintenance resulting from these deficiencies typically includes repair or replacement of the defective component on the overhead system. Remediation activities are identified on the inspection record within the GIS.

An example of a reported infrared inspection result on the overhead system is shown in Figure 5.3-35.

Item #1



Object Emissivity	0.95
Object Distance	15.0 m
Atmospheric Temperature	17.0 °C
Relative humidity	50%



Location

Pole Location #**8-090**
Woodlawn Road at Northwood Drive
WELLAND.

Description

Road phase live/hot line clamp on lowest circuit.

Observation at 11/1/2023 9:17:41 AM

Fault Bx1 **160.2 °C** Ok Bx2 T.Rise... **143.2 °C** PRIORITY:

Figure 5.3-35: Sample Infrared Inspection Result - Overhead System

5.3.3.2.4 Pole Testing and Inspection

Pole testing and OH equipment visual inspection is performed on a five-year cycle. The cycle map is illustrated in Figure 5.3-36. There are ten areas defined for pole testing. On average, two of the ten areas are tested annually. The pole inspection schedule for the forecast period is included in Table 5.3-15

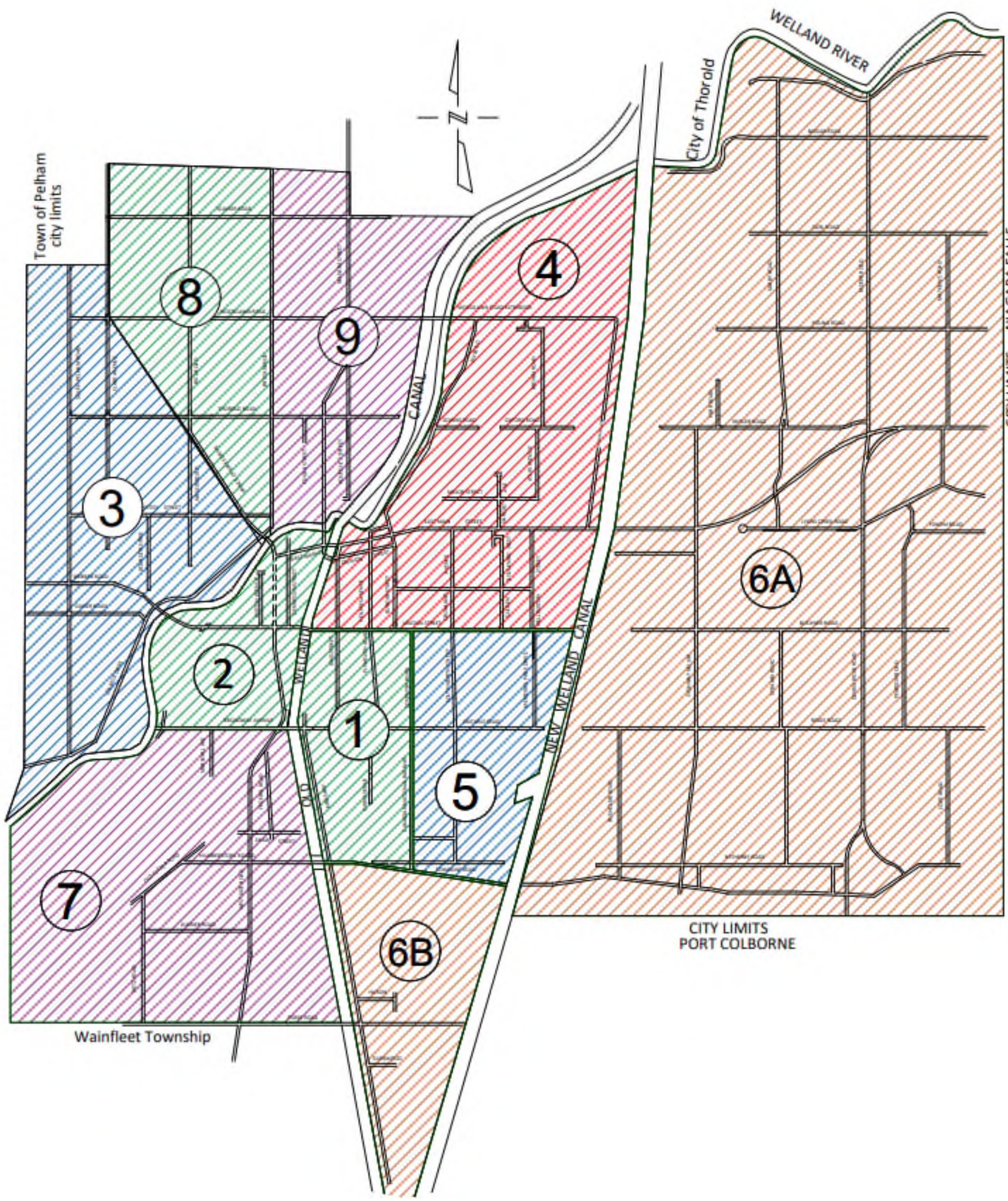


Figure 5.3-36: Pole Testing Cycle Map

Pole Inspection Schedule						
Area	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**
1				X		
2				X		
3	X					X
4			X			
5	X					X
6A		X				
6B		X				
7					X	
8				X		
9					X	

Table 5.3-15: Pole Inspection Schedule - Forecast Period

Pole testing is predictive maintenance that determines the asset's integrity and remaining strength. Since 2022, WHESC has changed its inspection method for poles, migrating from visual / sound and bore techniques to testing using the Polux device. The Polux based test results in an indication of pole strength and a determination of the time horizon in which replacement will be required.

In addition to the pole test, the overhead equipment at each pole location is also visually inspected by a qualified contractor. Deficiencies are noted inclusive of missing guy wire guards, pole identification, vegetation encroachment, damaged ground conductors, and damaged guards. Any noted minor deficiency will result in condition-based maintenance for repair. All inspection data is captured in real-time and subsequently imported into the WHESC's GIS.

Poles identified as being at imminent risk of failure are replaced immediately. Otherwise, pole condition results are assessed against the consequence of failure risk. A risk score is assigned to the pole asset derived from infrastructure that the pole is supporting. The score is determined with consideration given to whether the pole supports primary or secondary circuits, the quantity of circuits, and the equipment being supported. The risk score and condition score are tabulated in the GIS and used in combination to identify a priority score for replacement. The priority score is used to sequence pole replacement-based investments and assists in levelizing system renewal based expenditures.

5.3.3.2.5 Vegetation Management

Vegetation management consists of tree clearing along right of ways containing overhead systems. Tree clearing is performed on a three-year cycle. The objective is to maintain clearances from vegetation to primary and secondary systems, based on Electrical Safety Authority guidelines.

Like pole testing, there are ten areas defined as candidates for tree clearing each year. Areas have been grouped such that the tree clearing volume is as consistent as possible year over year. On average, three areas are completed per year and all areas are maintained within the three-year cycle. The tree trimming cycle map is shown in Figure 5.3-37.

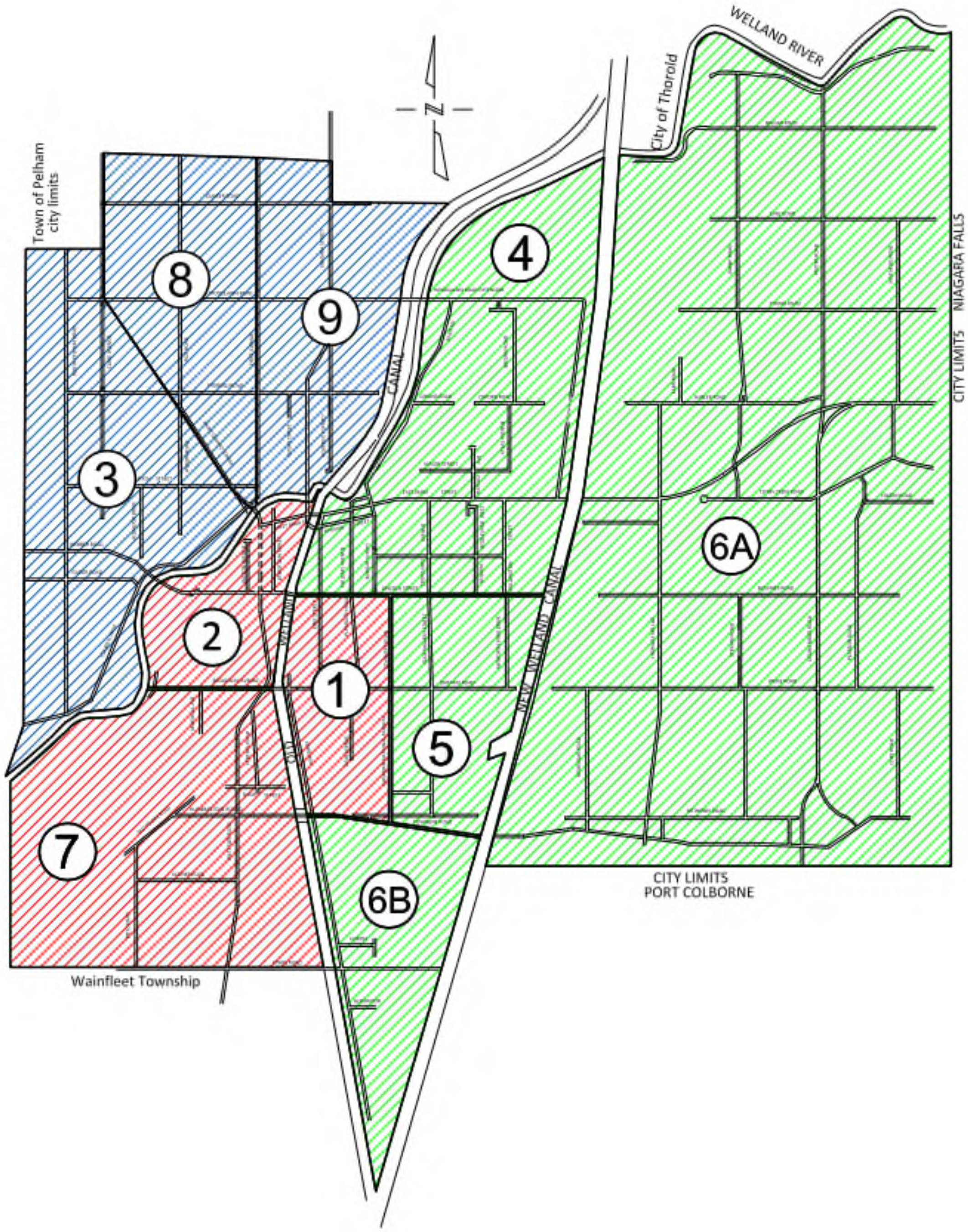


Figure 5.3-37: Tree Clearing Cycle Map

Tree clearing is a preventative maintenance activity, well correlated to system reliability. System reliability during significant weather events, particularly those involving high winds and ice accumulation, is further at risk when influenced by tree contact. Maintaining tree clearance not only benefits public safety, but it also positions the distribution system to perform during severe weather.

WHESC relies on third party services consisting of Utility Arborists to conduct tree clearing activities. Each year, the three subset areas may be awarded to multiple third parties to manage the overall expenditure.

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

5.3.3.3.1 Prioritization of Asset Replacement

WHESC's ACA identifies health indices for each asset class where proactive asset management processes are employed. System renewal investments have been selected over the forecast period to address condition issues in a manner that sustains the asset population at rational pace, while maintaining or improving distribution system performance.

WHESC has analyzed each asset class and developed investment alternatives to address prioritized asset deficiencies. The result of this analysis is the identification of projects to renew asset health. These project alternatives have been evaluated against asset management objectives identified in Section 5.3.1.1. For each identified project alternative, a high-level execution cost estimate is produced and captured in a project registry.

Once system renewal alternatives are selected, projects are ranked against asset management objectives. Beyond adherence of a given project to objectives, other factors will influence project sequencing. For example, an overhead line rebuild located upstream of a proposed underground subdivision rebuild may need to be executed in advance, even though the project may rank lower against objectives. To appropriately manage overall capital expenditures, managing project dependencies is required.

5.3.3.3.2 Forecasting and Strategies for Operating within Budget Envelopes

Projects are slated for execution in a given year based on priority ranking and any required sequencing. Project execution budgets are derived based on known material and equipment costs and a projection of labour and third party service costs using financial metrics gathered historically. Objective outcomes in determining system renewal scope each year is to levelize capital expenditures over the forecast period and to maintain adherence to business plan budget estimates.

Variance analysis is conducted on capital expenditures annually and reviewed by the WHESC board level Operations Committee. In addition to ensuring that plan execution is in alignment with strategic goals and objectives, the committee reviews and recommends adjustment to projects prioritized over the forecast period where necessary to align with approved budget envelopes identified in the business plan.

Non-discretionary capital investments required in a year may change the amount of system renewal expenditure budgeted for that period, resulting in project deferral (either in part or whole). Changes in System Access based investments from the business plan, which are generally mandatory, have the greatest influence on the pacing of System Renewal based investments.

5.3.3.3.3 Risks of Proceeding / Not Proceeding

Risk is factored into the prioritization and selection of capital expenditures as described in Section 5.3.1.3 above. The process described in this section is used to determine the prioritized list of captial projects and programs over the forecast period. Projects are prioritized and selected based on the scoring methodology described in Section 5.4.2. Projects are gauged for alignment to corporate goals and asset management criteria presented in Table 5.3-1. The risk of project or program deferral is ultimately assessed using the numeric scoring defined in Table 5.4-17 and Table 5.4-18.

The process of determining investment alternatives may involve the assessment of a "do nothing" approach to addressing a specific need. The material project narratives in Appendix 5-A identify where WHESC has assessed a "do nothing" alternative.

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

Since the last DSP filed as part of the 2017 cost of service application, WHESC has conducted two ACAs. The latest, conducted in 2023 better positions WHESC to holistically manage asset health. Data inputs to the ACA process have significantly improved as WHESC has expanded the scope of attribute data housed within its GIS based on prior ACA data availability-based recommendations. The input data to the ACA process now includes results from third party pole testing.

Integration of ACA health index data into the GIS, along with data analytics available through SmartMap, position WHESC to identify and manage specific assets at risk in real time. Asset utilization and performance is monitored daily through SmartMap, providing a refined approach to managing reactive maintenance.

5.3.4 System Capability Assessment for REG & DERs

WHESC has developed a Renewable Energy Generation (REG) Investment Plan, outlining WHESC's ability to connect DERs to its distribution system. This plan is attached in Appendix 5-F.

WHESC, currently has 18.2 MW of DERs connected to its distribution system as shown in Section 5.2.2.10. WHESC has forecasted REG/DER connections from 2024 through to 2029 at approximately 9.2MW. The forecast is based on assumed net metering facility deployments with recent changes to O. Reg. 541/05: Net Metering. WHESC is also aware of two contemplated load displacement facilities which are incorporated into the forecast.

As identified in Section 5.2.2.10, the most constrained distribution circuit in WHESC's system has the capability of connecting 8MW of REG/DER in addition to forecasted facilities.

5.3.5 CDM Activities to Address System Needs

Conservation and Demand Management ("CDM") initiatives that have been implemented by WHESC over the historical period have resulted in some decline of energy consumption and peak demand. These initiatives have not reduced distribution system demand to a degree that avoids the need for major system renewal investments. CDM activity under the provincial 2021-2024 CDM framework is centralized under the IESO.

The 2021 CDM guidelines have been replaced by the "Non-Wires Solutions Guidelines for Electricity Distributors". The new document includes guidance on incentive mechanisms for LDCs using third-party DERs as non-wires solutions ("NWS"). The guidance also adds clarity to the role of NWS in regional planning exercises. Managed EV charging has also been added as a potential NWS activity that distributors may consider in addressing distribution system needs.

The new guidelines continue to indicate that any efforts by the distributor to support IESO programs should not duplicate efforts of IESO's activities. This DSP has considered the new guidelines and the use NWS when making investment decisions. The guidance suggests that electrical system needs with an expected capital cost of $2 million or more necessitate the consideration of NWS when evaluating alternatives to address an investment need. WHESC confirms that none of the contemplated investments to address a need in this DSP exceed that threshold.

It is important to highlight that the recent IRRP was completed before the new guidelines were released, however NWS were considered through the process of addressing the capacity needs of the Niagara area at a transmitter level.

In addition to adhering to the new guidelines pertaining to NWS, WHESC continues to work with customers, supporting energy efficiency initiatives and DER deployments within customer facilities. WHESC's system has visibility to DERs, used in part for customer load displacement while also reducing the system peak. WHESC considers the impact of NWS on the distribution system to be positive as these typically mitigate load growth and shift demand away from on-peak periods.

5.4 Capital Expenditure Plan

This section details WHESC's five-year capital plan in the forecast period from 2025 through to 2029. The plan was developed as a direct result of the planning process, described in Section 5.3.1.

The following sections describe historical capital expenditure performance, forecast capital expenditures, and comparison of historical and forecast expenditures:

Section 5.4.1.1 – Historical Capital Expenditure Performance: This section analyzes the performance of the DSP's historical period and includes an explanation of variances by investment category.

Section 5.4.1.2 – Forecast Capital Expenditures: This section provides an analysis of planned expenditures during the forecast period.

Section 5.4.1.3 – Comparison of Forecast and Historical Expenditures: This section provides an analysis of expenditures during the DSP's forecast period vs. the historical period.

5.4.1 Capital Expenditure Summary

The capital expenditure summary provides an overview of the investment plan over a 13 year period. This includes eight historical years and five forecasted years. The investments are allocated into one of four categories based on the primary investment driver. Capital investments over the DSP planning period from 2025 through 2029 have been categorized to align with the four DSP investment categories.

The overview of the OEB approved amounts from WHESC's previous filing is illustrated in Table 5.4-1 and the forecast amounts area broken down by category are provided in Table 5.4-2. Further details can be found in Exhibit 2, Appendix 2-AA, and Exhibit 2, Appendix 2-AB of WHESC's COS application.

CATEGORY	Historical Period																					Bridge Year
	2017			2018			2019			2020			2021			2022			2023			2024
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000
System Access																						
Gross Capital	140	76	45.7%	250	424	69.6%	250	474	89.7%	190	1,548	714.7%	150	1,043	595.7%	715	1,063	48.6%	490	2,143	337.4%	2,329
Capital Contributions	-	- 38	--	-	- 171	--	-	- 342	--	-	- 1,122	--	-	- 712	--	- 50	- 637	1174.3%	- 50	- 1,219	2338.6%	- 1,720
Net Capital	140	38	-73.1%	250	253	1.2%	250	132	-47.1%	190	426	124.3%	150	332	121.0%	665	425	-36.0%	440	924	110.0%	609
System Renewal																						
Gross Capital	1,735	1,788	3.1%	1,495	1,418	-5.2%	1,775	1,936	9.1%	1,920	2,272	18.3%	1,770	2,246	26.9%	2,185	2,614	19.7%	2,200	2,328	5.8%	2,405
System Service																						
Gross Capital	80	29	-64.4%	260	113	-56.7%	35	103	194.3%	35	79	125.1%	35	267	663.1%	210	313	49.0%	220	141	-35.9%	160
General Plant																						
Gross Capital	155	358	130.9%	305	563	84.7%	400	1,201	200.2%	295	314	6.5%	525	455	-13.3%	205	122	-40.5%	460	278	-39.6%	535
Totals																						
Gross Capital	2,110	2,251	6.7%	2,310	2,517	8.98%	2,460	3,714	50.97%	2,440	4,213	72.67%	2,480	4,012	61.8%	3,315	4,112	24.0%	3,370	4,891	45.1%	5,429
Capital Contributions	-	- 38	--	-	- 171	--	-	- 342	--	-	- 1,122	--	-	- 712	--	- 50	- 637	1174.3%	- 50	- 1,219	2338.6%	- 1,720
Net Capital Expenditure	**2,110**	**2,212**	**4.9%**	**2,310**	**2,347**	**1.6%**	**2,460**	**3,372**	**37.1%**	**2,440**	**3,091**	**26.7%**	**2,480**	**3,300**	**33.1%**	**3,265**	**3,475**	**6.4%**	**3,320**	**3,671**	**10.6%**	**3,709**
System O&M	**3,314**	**3,379**	**2.0%**	**3,380**	**3,398**	**0.5%**	**3,671**	**3,601**	**-1.9%**	**3,759**	**3,520**	**-6.4%**	**3,960**	**3,662**	**-7.5%**	**3,879**	**3,767**	**-2.9%**	**4,054**	**3,826**	**-5.6%**	**4,175**

Table 5.4-1: Historical Capital Expenditures and System O&M

CATEGORY	Forecast Period				
	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital	1,577	1,624	1,672	1,724	1,775
Capital Contributions	- 974	- 1,004	- 1,034	- 1,065	- 1,097
Net Capital	602	620	638	659	678
System Renewal					
Gross Capital	2,884	3,117	2,795	3,242	3,315
System Service					
Gross Capital	242	499	482	364	272
General Plant					
Gross Capital	955	498	581	226	271
Totals					
Gross Capital	5,658	5,738	5,530	5,556	5,633
Capital Contributions	- 974	- 1,004	- 1,034	- 1,065	- 1,097
Net Capital Expenditure	**4,683**	**4,734**	**4,496**	**4,491**	**4,536**
System O&M	**4,705**	**4,889**	**5,063**	**5,182**	**5,336**

Table 5.4-2: Forecast Capital Expenditures and System O&M

5.4.1.1 Historical Capital Expenditure Performance

Performing variance analysis is essential to the continuous improvement feedback that WHESC employs in its planning process. Future investment decisions in the asset management process, such as renewal pacing, are better informed from the results of this analysis.

The balance of this section summarizes annual variances in each investment category, for the historical period. For the period 2017 to 2021, the variance analysis is planned to actuals. For 2022, and 2023, the variance analysis is budget to actuals.

5.4.1.1.1 2017 Planned vs. Actuals

Category	2017				Justification
	Plan.	Act.	Var.	Var.	
	$ '000		$ '000	%	
System Access Gross	140	76	- 64	-45.7%	Variance is below the materiality threshold.
System Renewal, Gross	1,735	1,788	53	3.1%	Variance is below the materiality threshold.
System Service, Gross	80	29	- 52	-64.4%	Variance is below the materiality threshold.
General Plant, Gross	155	358	203	130.9%	The increased expenditure above plan in 2017 was due to the unplanned purchase of CIS licensing based on the decision to move IT services from a hosted solution to on premise. This was to manage ongoing Opex and cybersecurity posture. Additionally, unplanned drainage and restoration work was required due to issues that arose with the oil/water separation system incorporated into the floor of the garage and truck bay area.
Total Capital, Gross	2,110	2,251	141	6.7%	See comments above.
Capital Contributions	-	- 38	- 38	--	Variance is below the materiality threshold.
Total Capital, Net	**2,110**	**2,213**	**103**	**4.9%**	**See comments above.**
System O&M	**3,314**	**3,379**	**65**	**2.0%**	

Table 5.4-3: Variance Analysis: 2017 Planned vs. Actuals

5.4.1.1.2 2018 Planned vs. Actuals

Category	2018				Justification
	Plan.	Act.	Var.	Var.	
	$ '000		$ '000	%	
System Access Gross	250	424	174	69.6%	This variance is due to the increase in connection of new residential subdivisions that were not in plan. Connection of residential subdivisions accounted for approximately $189K of gross system access expenditures and was largely offset by capital contributions.
System Renewal, Gross	1,495	1,418	- 77	-5.2%	This variance is due to the deferral of UG system renewal to 2019 to accommodate additional requirements in OH rewnwal.
System Service, Gross	260	113	- 147	-56.7%	The majority of this variance is due to municipal station relay upgrades below plan. The budget was based on contract services performing relay replacements at two substations for $175K. WHESC completed relay upgrades at MS1 with internal resources for $25K. The remaining substation work was defered to subsequent years, allowing internal resources to complete the relay upgrade scope.
General Plant, Gross	305	563	258	84.7%	The increased expenditure above plan in 2018 was due to the unplanned purchase of Great Plains financial software licensing based on the decision to move IT services from a hosted solution to on premise. This was a continued effort to manage ongoing Opex and cybersecurity posture. Additionally, two used Altec single bucket trucks were acquired to manage fleet deficiencies not accounted for in the previous DSP.
Total Capital, Gross	2,310	2,517	207	9.0%	See comments above.
Capital Contributions	-	- 171	- 171	--	Variance is below the materiality threshold.
Total Capital, Net	**2,310**	**2,347**	**37**	**1.6%**	**See comments above.**
System O&M	**3,380**	**3,398**	**18**	**0.5%**	

Table 5.4-4: Variance Analysis: 2018 Planned vs. Actuals

5.4.1.1.3 2019 Planned vs. Actuals

Category	2019				Justification
	Plan.	Act.	Var.	Var.	
	$ '000		$ '000	%	
System Access Gross	250	474	224	89.7%	This variance is due to the increase in connection of new residential subdivisions that were not in plan. Connection of residential subdivisions accounted for approximately $298K of gross system access expenditures and was largely offset by capital contributions.
System Renewal, Gross	1,775	1,936	161	9.1%	This variance is due to above plan expenditures on muncipal substation upgrades. MS8 replacement was 29K above plan due to material and contract service costs. The Phase 1 replacement of MS9 was 43K above plan due to scope change requirements on civil work and contract service costs. The switchgear at MS10 experienced pre-mature failure and was replaced with a spare unit at 46K, including re-cabling. In review of contingency plans for loss of a single transformer in WHESC's substation fleet, MS12 was identified as islanded due to lack of rigid interties on the 4.16kV system. A spare transformer was deployed as an on-potential backup at MS12.
System Service, Gross	35	103	68	194.3%	The original plan called for SCADA communication upgrades on exiting SCADA switches. As part of WHESC's grid modernization plan, WHESC also continued the installation of an additional automated device on the M17 circuit. Relay upgrades were also performed at MS10, completed by internal staff.
General Plant, Gross	400	1,201	801	200.2%	The increased expenditure above plan in 2019 was in part due to corporate IT server deployment to migrate systems from a hosted enironment to on premise at a cost of $132K. Additionally, software license requriements and CIS data conversion were required at a cost of $158K. The was the final phase to move IT services from a hosted solution to on premise to manage ongoing Opex and cybersecurity posture. Additionally, a digger truck was purchased to replace an end of life unit from 1990. This advanced the purchase previously contemplated in 2021, at a cost of $360K. A reel trailer was purchased at a cost of $58K.
Total Capital, Gross	2,460	3,714	1,254	51.0%	See comments above.
Capital Contributions	-	- 342	- 342	--	Capital contributions were not budgeted in the 2019 plan.
Total Capital, Net	**2,460**	**3,372**	**912**	**37.1%**	**See comments above.**
System O&M	**3,671**	**3,601**	**- 70**	**-1.9%**	

Table 5.4-5: Variance Analysis: 2019 Planned vs. Actuals

5.4.1.1.4 2020 Planned vs. Actuals

Category	2020 Plan. ($ '000)	2020 Act. ($ '000)	2020 Var. ($ '000)	2020 Var. (%)	Justification
System Access Gross	190	1,548	1,358	714.7%	The variance is attributed to subdivision expansions not in the original DSP. Residential subdivision development volumes signifianctly increased moving into 2020, affecting the required captial investment by WHESC. Gross capital expenditure on residential subdivisions was $1.3M, largely offset by capital contributions. General service demand work also increased, accounting for an expenditure $150K above plan.
System Renewal, Gross	1,920	2,272	352	18.3%	Phase 2 of MS9 was accelerated from the original plan of execution in 2021 to coordiante with future voltage converison projects ($150K). Additional pole replacements were completed based on prior years pole inpection results (approximately 43 additional poles) at a cost of $213K.
System Service, Gross	35	79	44	125.1%	Variance is below the materiality threshold.
General Plant, Gross	295	314	19	6.5%	Variance is below the materiality threshold.
Total Capital, Gross	2,440	4,213	1,773	72.7%	See comments above.
Capital Contributions	-	- 1,122	- 1,122	--	Capital contributions were not budgeted in the 2020 plan. Increase from 2019 is attributed to the increase in contributions related to Residential Subdivisions and General Service demand work.
Total Capital, Net	**2,440**	**3,091**	**651**	**26.7%**	**See comments above.**
System O&M	**3,759**	**3,520**	**- 239**	**-6.4%**	

Table 5.4-6: Variance Analysis: 2020 Planned vs. Actuals

5.4.1.1.5 2021 Planned vs. Actuals

Category	2021				Justification
	Plan.	Act.	Var.	Var.	
	$ '000		$ '000	%	
System Access Gross	150	1,043	893	595.7%	The variance is attributed to subdivision expansions not in the original DSP. Residential subdivision volumes continued steady moving into 2021, affecting the required gross captial investment required. Gross capital expenditure on residential subdivisions was $681K, largely offset by capital contributions.. Line relocations not contemplated in the previous plan accounted for $185K of the variance. Meter purchases were in excess of plan by $65K related to new connection growth.
System Renewal, Gross	1,770	2,246	476	26.9%	Additional pole replacements were completed based on prior years pole inpection results (approximately 48 additional poles) at a cost of $260K. Unplanned transformer replacement due to unit failure accounted for $76K. Regent Street was rebuilt following significant deficiencies identified through 2021 pole inspections. The deficiencies were associated with a critical river crossing structure (project cost = $87K)
System Service, Gross	35	267	232	663.1%	As part of WHESC's grid modernization deployments, three Viper reclosers were deployed on the 28kV distribution system at an additional cost of $190K. MS5 relay upgrades (not in plan) were completed by internal staff at a cost of $27K.
General Plant, Gross	525	455	- 70	-13.3%	Replacement of a light duty truck was deferred to levelize captial spend (50K). Large truck purchases were $20K under plan.
Total Capital, Gross	2,480	4,012	1,532	61.8%	See comments above.
Capital Contributions	-	- 712	- 712	--	Capital contributions were not budgeted in the 2021 plan. The increase from 2020 is attributed to the increase in contributions for residential subdivisions and relocation projects.
Total Capital, Net	**2,480**	**3,300**	**820**	**33.1%**	**See comments above.**
System O&M	**3,960**	**3,662**	**- 298**	**-7.5%**	

Table 5.4-7: Variance Analysis: 2021 Planned vs. Actuals

5.4.1.1.6 2022 Budget vs. Actuals

Category	2022 Plan. ($ '000)	2022 Act. ($ '000)	2022 Var. ($ '000)	2022 Var. (%)	Justification
System Access Gross	715	1,063	348	48.6%	This variance is partly due to the connection of new residential subdivisions that were not in plan. Connection of residential subdivisions accounted for approximately $472K of gross system access expenditures and was largely offset by capital contributions. Increased demand in general service connections ($110K) also contributed to the variance. Additionally, developer funded expansion / relocation work occurred, not planned for in 2022.
System Renewal, Gross	2,185	2,614	429	19.7%	An unplanned failure of MS11 resulted in an $86K transformer replacement. Additionally, WHESC accelerated distribution transformer ordering in 2021 due to procurement issues associated with the pandemic. Stock levels increased as a result. With the additional impact of per unit cost increases and an increase in units on hand for pending billable work, additions to transformers in inventory accounted for $346K of the variance.
System Service, Gross	210	313	103	49.0%	As part of WHESC's grid modernization deployments, an additional Viper recloser was deployed on the 28kV distriibution system at an additional cost of $50K. RTU replacements were in excess of plan by approximately $11K.
General Plant, Gross	205	122	- 83	-40.5%	Computer hardware upgrades were deferred ($16K). Customer portal and mCare deployment were completed under plan ($35K). Bulding upgrades were deferred ($25K)
Total Capital, Gross	3,315	4,112	797	24.0%	See comments above.
Capital Contributions	- 50	- 637	- 587	1174.3%	Capital contributions were budgeted related to the new general service connections forecast. Additional contributions received were associated with demand work in excess of plan, residential subdivisions, and relocations/expansions not in plan.
Total Capital, Net	**3,265**	**3,475**	**210**	**6.4%**	**See comments above.**
System O&M	**3,879**	**3,767**	**- 112**	**-2.9%**	

Table 5.4-8: Variance Analysis: 2022 Budget vs. Actuals

5.4.1.1.7 2023 Budget vs. Actuals

Category	2023 Plan.	2023 Act.	2023 Var.	2023 Var.	Justification
	$ '000		$ '000	%	
System Access Gross	490	2,143	1,653	337.4%	This variance is partly due to the increase in connection of new residential subdivisions that were not in plan. Connection of residential subdivisions accounted for approximately $1.2M of gross system access expenditures and was largely offset by capital contributions. The balance of the variance is attributed to: line expansions not in plan ($203K), increased residential service connection costs not in plan ($207K), increased general service connections ($226K), and increased meter procurement costs (inventory management due to significant post-COVID lead times - $165K).
System Renewal, Gross	2,200	2,328	128	5.8%	This variance is attributed to a pole line rebuild project advanced to coordinate with new development ($83K). An additonal project was scoped in lieu of individual pole replacements due to overall asset condition in the area and the opportunity for voltage conversion ($63K).
System Service, Gross	220	141	- 79	-35.9%	One grid modernization deployment was advanced in late 2023. The MS4 protection upgrade was completed under plan ($38K).
General Plant, Gross	460	278	- 182	-39.6%	Computer software upgrades for Green Button were implemented through subscription services rather than on premise ($75K). Fuel system was implemented below plan ($64K) by establishing a leasing arrangement for tanks rather than purchase.
Total Capital, Gross	3,370	4,891	1,521	45.1%	See comments above.
Capital Contributions	- 50	- 1,219	- 1,169	2338.6%	Additional contributions received were associated with residential subdivisions and demand work in excess of plan and line expansions not in plan.
Total Capital, Net	**3,320**	**3,671**	**351**	**10.6%**	**See comments above.**
System O&M	**4,054**	**3,826**	**- 228**	**-5.6%**	

Table 5.4-9: Variance Analysis: 2023 Budget vs. Actuals

5.4.1.2 Forecast Capital Expenditures

WHESC's investment plan calls for $22.9M of net capital expenditures in the forecast period of 2025 through to 2029. The investment plan is a product of the planning process and five-year business plan.

Table 5.4-10 summarizes the investment plan's gross capital expenditures over the period 2025 through 2029:

CATEGORY	Forecast Period				
	2025	2026	2027	2028	2029
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System Access	1,577	1,624	1,672	1,724	1,775
System Renewal	2,884	3,117	2,795	3,242	3,315
System Service	242	499	482	364	272
General Plant	955	498	581	226	271
Total Gross Capital	**5,658**	**5,738**	**5,530**	**5,556**	**5,633**

Table 5.4-10: Forecast Capital Expenditures 2025-2029

Figure 5.4-1, shown below, illustrates that WHESC's planning process results in a levelized capital expenditure over the forecast period. Discretionary investments will vary over the investment horizon to accommodate projects that are prioritized due to being mandatory or deemed urgent in terms of WHESC's asset management objectives.

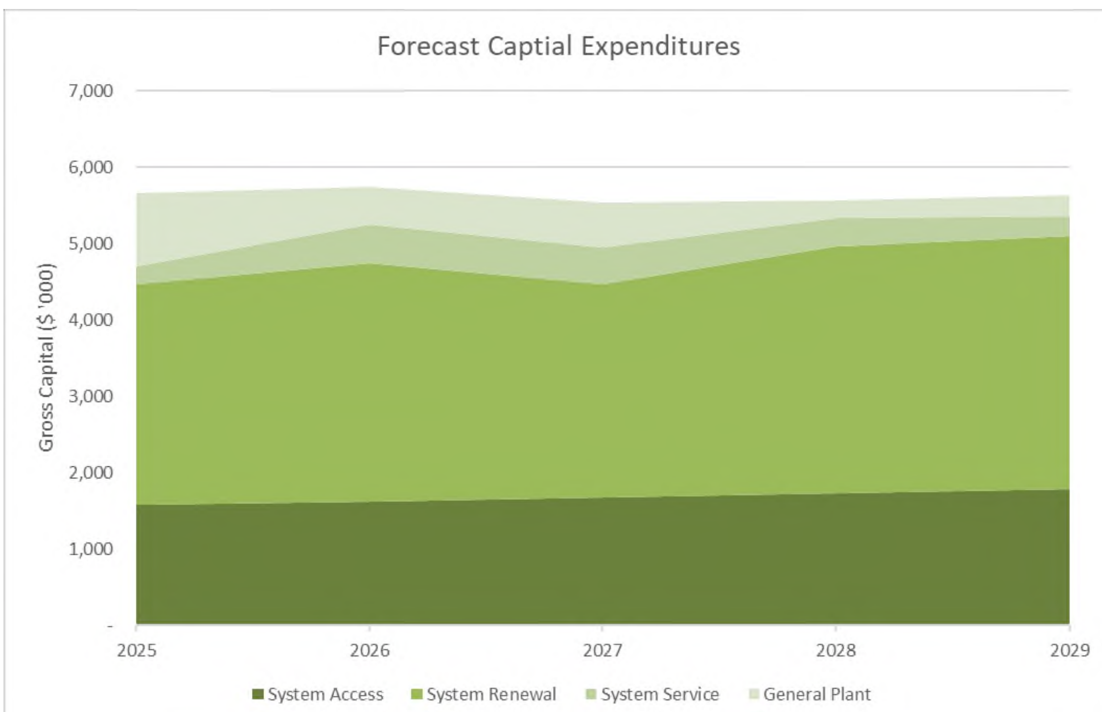


Figure 5.4-1: Forecast Capital Expenditures 2025-2029

The balance of this section summarizes the categoric planned investments over the period.

5.4.1.2.1 System Access Investments

System Access investments in the distribution system accommodate new connections or facilitate new infrastructure development. Investments in this category must occur annually as Welland Hydro is obligated to provide access to the distribution system and its electricity services. Projects include the connection of new residential subdivisions, connection of new commercial and industrial services, and the relocation of assets based on road infrastructure needs. The forecasted investments are illustrated in Table 5.4-11 and Figure 5.4-2. With reference to Table 5.4-1, forecast capital contributions are based on historical demand for new service requirements. In recent historical years, there were significant contributions for committed subdivisions and line expansion work that caused upward pressure on gross system access expenditures and capital contributions.

System Access	Test Year	Forecast Period				Total	Percentage of Total
	2025	2026	2027	2028	2029		
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	
Residential Services	46	48	49	51	52	246	3%
General Services	240	247	254	262	270	1,273	15%
Subdivisions	1,136	1,170	1,205	1,242	1,279	6,032	72%
Meters	154	160	164	169	174	821	10%
Gross Capital	**1,576**	**1,624**	**1,672**	**1,724**	**1,775**	**8,372**	**100%**

Table 5.4-11: Forecast System Access Expenditures

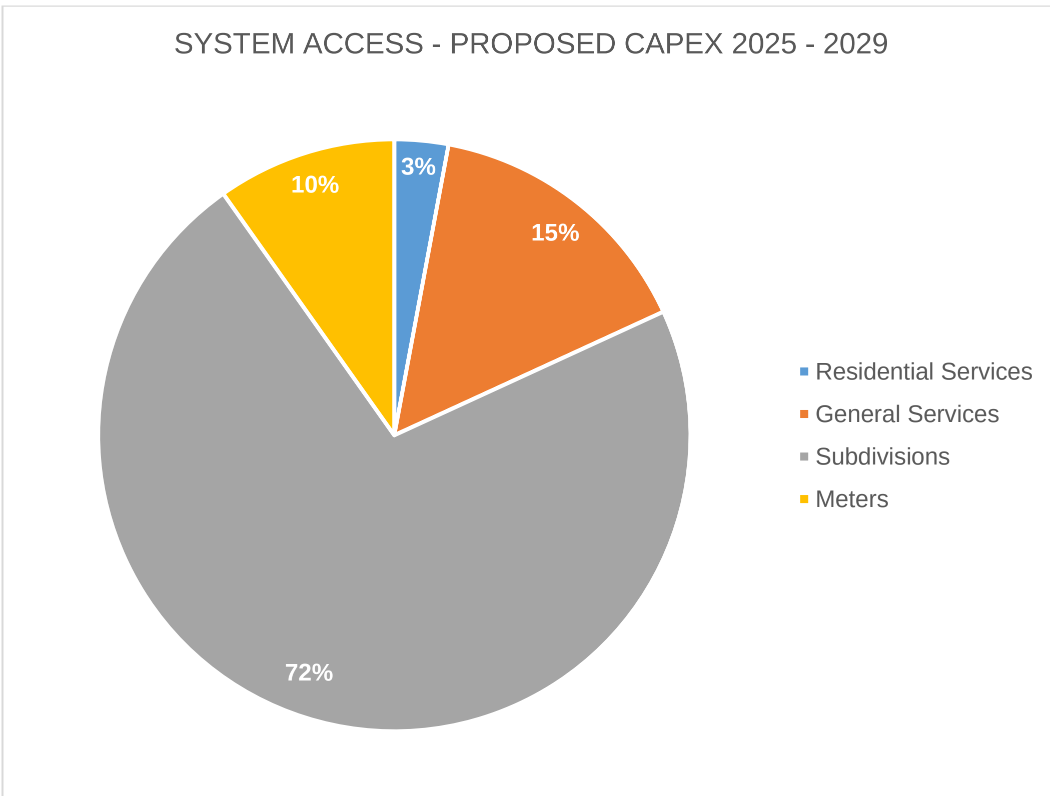


Figure 5.4-2: Forecast System Access Investment Ratios

System Access investments account for approximately 30% of WHESC's gross capital expenditure in the forecast period. The planned investments in system access are based on recent historical experience and information gathered through stakeholder consultations. WHESC gains valuable information on proposed developments through participation in municipally driven consultation activities.

Subdivision Developments

Approximately 72% of system access spending in the forecast period is related to subdivision expansions in the service territory. WHESC has referenced recent historical expenditures related to residential subdivision development in conjunction with current and pending agreements to forecast the expenditure level in 2025. Based on municipal consultations, along with growth projections in the City of Welland and Niagara Region, WHESC anticipates residential subdivision development to remain consistent in the forecast period.

General Services

Facilitating connection of commercial and industrial services to WHESC's distribution system accounts for 15% of planned investment in the forecast period. Included in these investments are new general service connections or upgrades to existing services. There has been growth in these connection expenditures in recent years, forming the basis for 2025 planned expenditure levels. With costs stabilizing post-COVID, expenditure levels have been forecasted to be consistent with inflation for the period beyond 2025.

Meters

Meter installation costs account for 10% of planned system access investments. There has been upward pressure on metering material post-COVID. Lead times on meters and instruments have exceeded twelve months in the recent historical period. This coupled with load growth has necessitated an increase in meters on hand to facilitate connections. Meters are capitalized upon receipt. WHESC expects its metering systems (head-end data acquisition) to remain in service throughout the forecast period.

Residential Services

At 3% of planned system access investments, residential service connections have been forecasted based on 2023 cost experience. While there was volatility in resource costs post-COVID, these have stabilized through 2023. This category includes new residential service connections or upgrades to existing services.

5.4.1.2.2 System Renewal Investments

These investments in the distribution system are generally to replace assets that are deteriorated and/or at end-of-life. The proposed investments are a result of the asset management process outlined in Section 5.3. The ACA is a key driver of investments in this category. Projects include the replacement of poles, overhead circuits, underground cables, transformers, and station assets.

The forecasted investments are illustrated in Table 5.4-12 and Figure 5.4-3.

System Renewal	Test Year	Forecast Period				Total	Percentage of Total
	2025	2026	2027	2028	2029		
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	
Substation Renewal	360	-	300	-	-	660	4%
Overhead Line Renewal	1,050	1,625	945	1,392	600	5,612	37%
Underground System Renewal	808	805	843	1,121	1,965	5,542	36%
Pole Replacement	302	311	321	330	340	1,605	10%
Transformer Replacement	161	166	171	176	182	856	6%
Reactive OH System Replacement	151	156	160	165	170	803	5%
Reactive UG System Replacement	52	53	55	56	58	273	2%
Gross Capital	**2,884**	**3,117**	**2,795**	**3,242**	**3,315**	**15,352**	**100%**

Table 5.4-12: Forecast System Renewal Expenditures

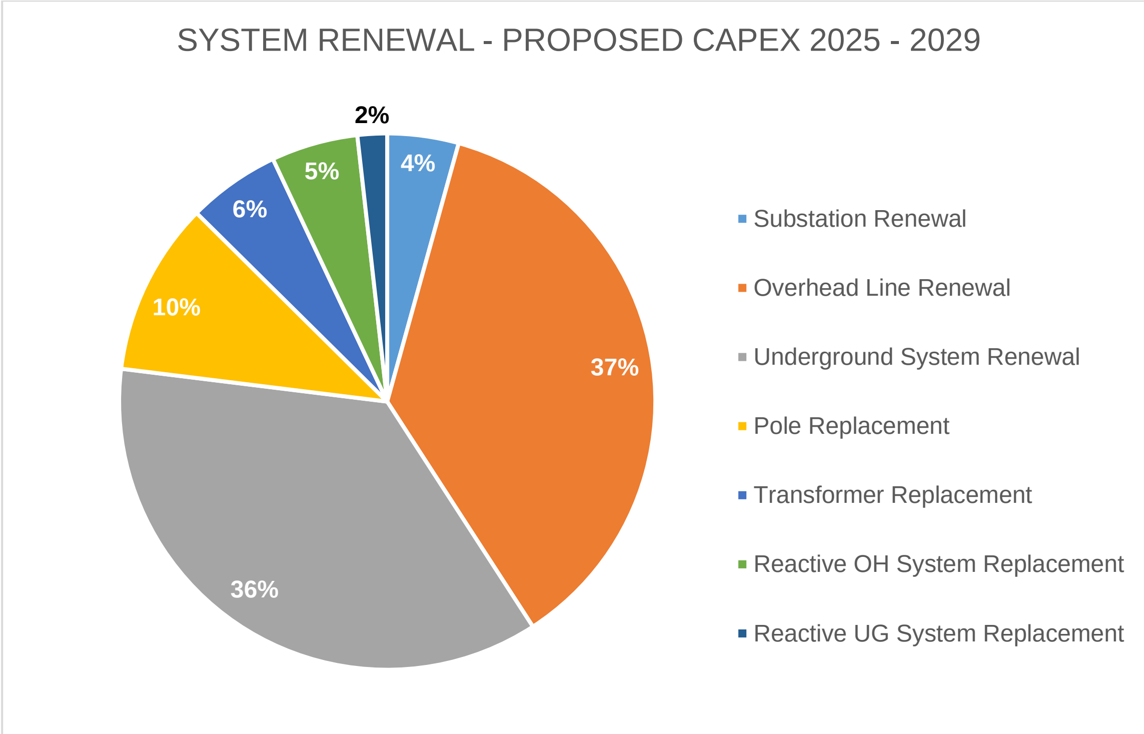


Figure 5.4-3: Forecast System Renewal Investment Ratios

System Renewal investments account for approximately 55% of WHESC's gross capital expenditure in the forecast period. The planned investments in system renewal are driven by asset condition. Sustainment of distribution asset health is a critical component of meeting WHESC's asset management objectives.

Overhead Line Renewal

Overhead line renewal projects account for 37% of the planned capital expenditure in the system renewal category. Project areas have been prioritized based on the need for proactive renewal of distribution system assets due to condition, safety, and reliability risk. Investments in this category target not only pole assets in deteriorated condition but restricted conductor elimination. Voltage conversion from 4.16 kV to 27.6 kV is in scope for 95% of the projects in the forecast period. This increases capacity in the subject areas and reduces reliance on substation assets.

Underground System Renewal

Underground system renewal based projects account for 36% of the planned capital expenditure in the system renewal category. Project areas have been prioritized based on the need for proactive renewal on cabling systems, pole trans, switchgear. Also included is conversion of rear-lot primary systems to pad-mount transformer supplied secondary, mitigating reliability and safety risk. Many of the areas of rear-lot construction on WHESC's primary distribution system contain restricted conductor. Voltage conversion to the 27.6 kV system is in scope for 75% of the projects in this program.

Pole Replacement

Individual pole replacements account for 10% of WHESC's planned system renewal investments. Pole condition is tracked in the GIS by incorporating inspection results. Data is analyzed in the GIS and poles are assessed based on asset health (identified as replacement required in the forecast period) and the risk of failure as described in Section 5.3.3.2.4. Pole replacements are prioritized based on the combined risk score.

Transformer Replacement

Approximately 6% of WHESC's planned system renewal investments target the replacement of transformers. Many of these replacements are associated with individual pole replacements. Also included in this category are reactive replacements of transformers based on experience in the historical period.

Reactive OH and UG System Replacements

Approximately 7% of system renewal investments in the forecast period are for unplanned capital projects that arise due to unexpected asset failure. This includes unplanned small overhead system rebuilds and small underground system replacements.

Substation Renewal

Substation capital expenditures account for 4% of WHESC's planned system renewal investments. Two of the power transformers in the poorest condition are scheduled for replacement. The projects also include replacement of 28kV supply in the two substation locations.

5.4.1.2.3 System Service Investments

System Service based investments are aimed at improving system reliability and resiliency. Projects include distributed automation deployments and new distribution circuit interties. Planned investments in the forecast period are predominantly WHESC's grid modernization investments.

The forecasted investments are illustrated in Table 5.4-13Table 5.4-11: Forecast System Access Expenditures and Figure 5.4-4.

System Service	Test Year	Forecast Period				Total	Percentage of Total
	2025	2026	2027	2028	2029		
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*	
Grid Modernization	242	249	257	264	272	1,285	69%
Grid Reinforcement	-	250	225	100	-	575	31%
Gross Capital	**242**	**499**	**482**	**364**	**272**	**1,860**	**100%**

Table 5.4-13: Forecast System Service Expenditures

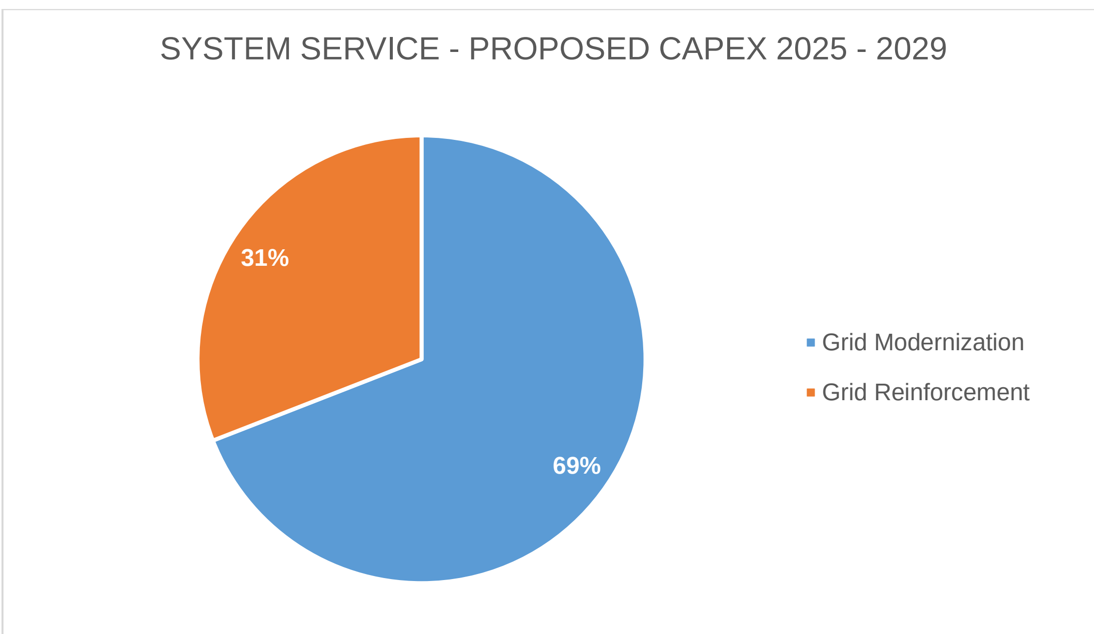


Figure 5.4-4: Forecast System Service Investment Ratios

System Service investments account for approximately 6.5% of WHESC's gross capital expenditure in the forecast period. The planned investments in system service are driven by WHESC's reliability and resiliency objectives.

Grid Modernization

WHESC's planned grid modernization expenditures account for 69% of system service investments. The forecast period includes the deployment of three automated switching devices per year on the 27.6 kV distribution system. These devices are incorporated into the 27.6 kV system protection scheme and are remote operable via SCADA.

Also included in this category of investment is the deployment of fault sensing devices at three locations on the 27.6 kV distribution system per year. These devices provide load, fault, and disturbance information to WHESC system control operators via SCADA.

Grid Reinforcement

WHESC has planned 31% of investments in system service to improve load transfer capability. The majority of investment is to establish two 28 kV circuit ties to Hydro One's Allanburg TS, in order to bridge the capacity gap that will exist at Crowland TS within the forecast period. With the planned in-service date for the replacement of Crowland TS in 2028, WHESC anticipates that load will exceed LTR at the existing TS within the period. This necessitates load transfer capability under contingency. The interties are expected to permit 10MW of load transfer capability.

5.4.1.2.4 General Plant Investments

These investments are required to support operation of the distribution system. Planned investments include large bucket trucks, light duty vehicles, information systems, and facility upgrades.

General Plant	Test Year	Forecast Period				Total	Percentage of Total
	2025	2026	2027	2028	2029		
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	
Office Equipment	50	18	5	5	6	84	3%
Information Systems	140	41	46	20	21	269	11%
Fleet	529	214	466	153	75	1,437	57%
Building Improvements	125	194	33	35	113	499	20%
Tools	111	31	32	12	57	242	10%
Gross Capital	**955**	**498**	**581**	**226**	**271**	**2,531**	**100%**

Table 5.4-14: Forecast General Plant Expenditures

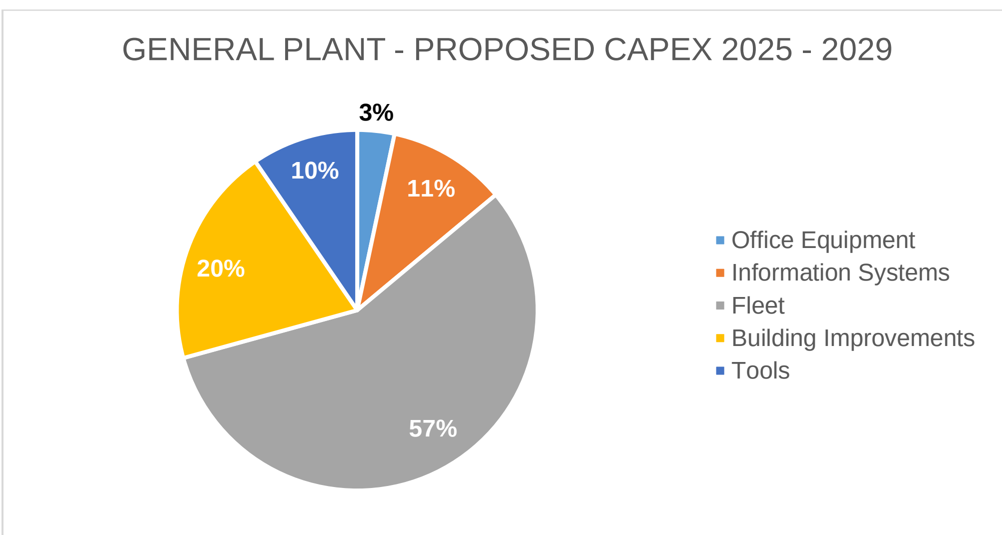


Figure 5.4-5: Forecast General Plant Investment Ratios

Geneal Plant investments account for approximately 9% of WHESC's gross capital expenditure in the forecast period. The planned investments in general plant are largely driven by asset condition.

Fleet / Rolling-Stock

Investments in fleet / rolling-stock account for 57% of WHESC's planned general plant expenditures. The proposed investments are based on WHESC's fleet assessment, conducted in support of this DSP. The following table summarizes fleet investments planned in the forecast period:

Year	Fleet Asset	Vehicle Type	Vehicle Model
2025	LV-53	Light Duty Pickup	2011 GMC Sierra
2025	HV-15 / HV-4	Single Bucket Trucks	2009 International 4400 / 2010 Freightliner M2 106
2025	TR-35	Reel Trailer	1982 Lge. Reel Trailer
2026	LV-3	Light Duty Pickup	2011 GMC Sierra
2027	LV-1	Light Duty Pickup	2011 GMC Canyon
2027	HV-11	Single Bucket Truck	2012 Freightliner M2 106
2028	LV-37	Light Duty Pickup	2016 Ford F150
2028	OT-32	Wheel Loader	2005 New Holland
2029	LV-60	Light Duty Van	2015 Nissan NV200

Table 5.4-15: Fleet / Rolling-Stock Replacements

The fleet replacement plan identified in Table 5.4-15, addresses the majority of fleet already at EOL based on condition and age. The replacement of two single bucket trucks in 2025, results in the elimination of one large vehicle in WHESC's fleet.

Building Improvements

Facility improvement expenditures account for 20% of WHESC's planned general plant expenditures in the forecast period. Based on the building condition assessment, conducted in support of this DSP, WHESC has prioritized facility improvements, separating conditional issues critical to the day-to-day operations from those that can be deferred. The result is planned minor renovations in the operations area of the building along with specific replacement expenditures in the garage and on HVAC systems.

Information Systems

Information system investments account for 11% of WHESC's planned general plant expenditures. The historical period included investments designed to improve WHESC's cybersecurity posture and manage ongoing OPEX. Investment requirements identified in the forecast period all target replacement of systems at or approaching EOL based on vendor support terms.

Tools

Approximately 10% of WHESC's planned general plant investments are for tools and test equipment. This includes meter test equipment, and equipment supporting maintenance activities in lines and substations.

Office Equipment

Office equipment accounts for 3% of WHESC's planned general plant investments. The majority of the planned investment is associated with replacement of office equipment and furniture associated with facility refurbishment.

5.4.1.2.5 Investments with Project Lifecycle Greater Than One Year

For capital projects spanning multiple years, costs remain under construction work-in-progress ("WIP") until the capital project is in service. Therefore, capitalization will only occur at the end of the project once it is in service.

5.4.1.3 Comparison of Forecast and Historical Expenditures

The subsections that follow, compare categoric investments in the historical and forecast period.

5.4.1.3.1 System Access

The historical and forecast system access expenditures are shown in Figure 5.4-6.

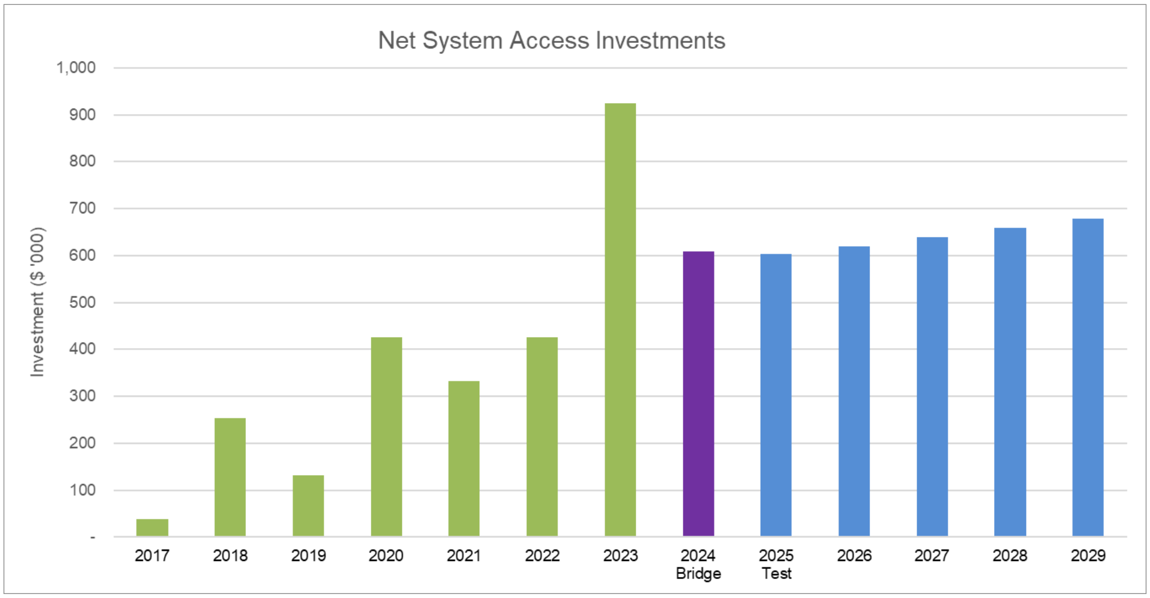


Figure 5.4-6: System Access Expenditure Comparison

System Access investment requirements (net of capital contributions) have increased through the historical period due to growth in connection requests, and resource cost increases through and post-COVID.

The forecasted system access investments are based on growth projections and committed or known development activity from WHESC participation in municipally driven consultations. The expenditure in 2023 was considered anomalous due to the significant connection growth that occurred in that post-COVID year. WHESC netted 690 new connections an increase of 2.8%

WHESC projects that new connection growth will continue to be strong as in recent historical years, particularly due to economic development and accelerated housing initiatives driven by the municipality. The investment plan in the forecast period maintains alignment with year-over-year increases in the recent historical period.

5.4.1.3.2 System Renewal

The historical and forecast system access expenditures are shown in Figure 5.4-7.

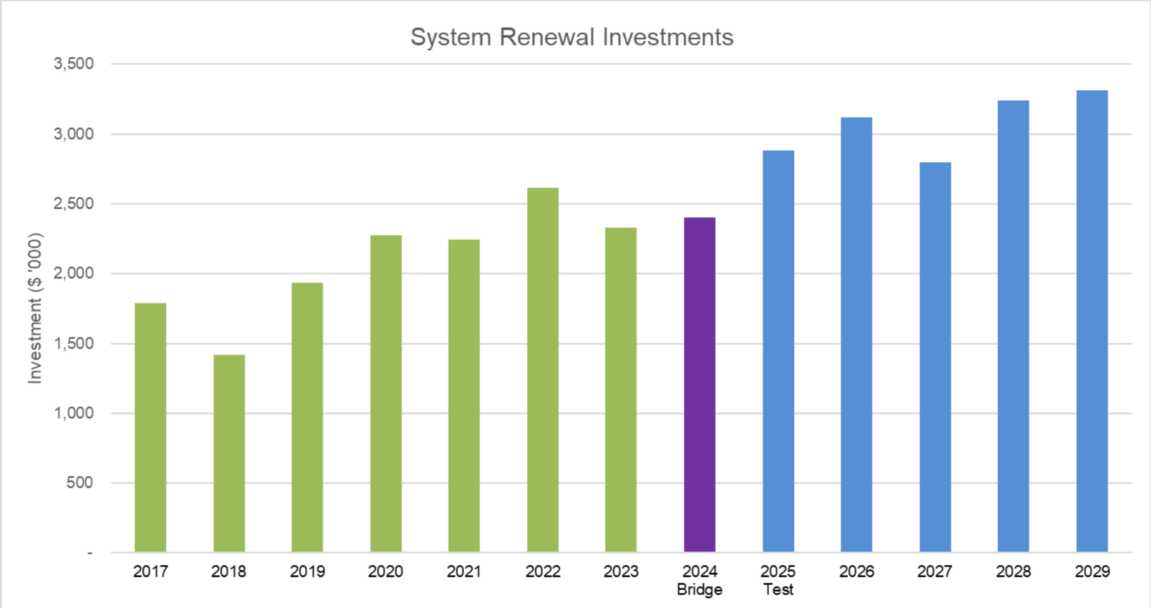


Figure 5.4-7: System Renewal Expenditure Comparison

The forecast average of system renewal investments in the five year forecast period is 44% higher than the than the historical period plus bridge year average. This is driven in part by refined ACA data, providing WHESC with invaluable insight on the required asset sustainment expenditure levels.

It is well recognized that resource costs in this post-COVID economic climate have increased significantly which is a factor in the increased investment required to sustain asset health. For major equipment like distribution transformers, more than 2x cost increases have been experienced since 2020.

Customer feedback has also been factored into the forecast expenditure levels. Customers have indicated, in areas related to asset replacement pacing, that WHESC should proceed at an accelerated pace in order to maximize system reliability and resiliency benefits. An additional 2.28M of expenditure has been planned over the five year forecast period as a result of this feedback. The increased expenditure replaces additional poles, wires, transformers, and underground systems while still maintaining annual expenditures below at or below sustainment levels.

5.4.1.3.3 System Service

The historical and forecast system access expenditures are shown in Figure 5.4-8.

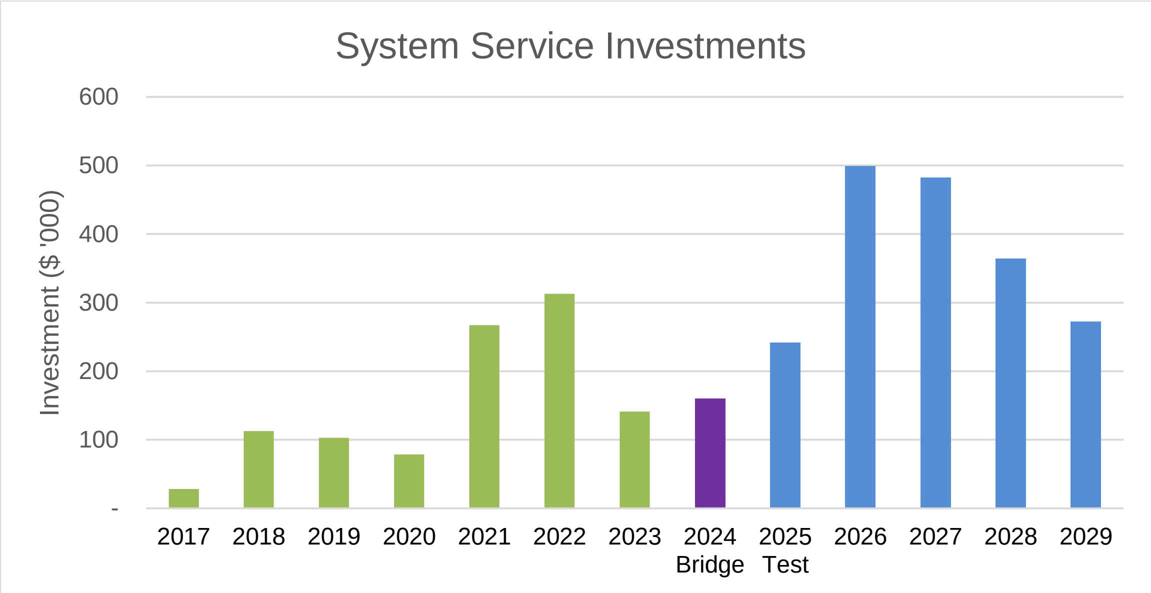


Figure 5.4-8: System Service Expenditure Comparison

The forecast average of system service investments in the five year forecast period is 147% higher than the than the historical period plus bridge year average. This is driven in part by the need for grid reinforcement expenditures planned in 2026, 2027, and 2028 in order to mitigate Crowland TS capacity shortfalls through the period while the TS is being replaced. These investments are not typical of WHESC's system service based expenditures.

System service investment levels in the forecast period have also been influenced by customer feedback. Through customer engagement activities associated with this plan, WHESC has learned that there is support for WHESC's grid modernization initiatives. Customers have indicated that WHESC should proceed with grid modernization implementation at an accelerated pace. An additional 400K of investment has been planned in the forecast period based on this feedback, increasing WHESC's system service based investments.

5.4.1.3.4 General Plant

The historical and forecast system access expenditures are shown in Figure 5.4-9.

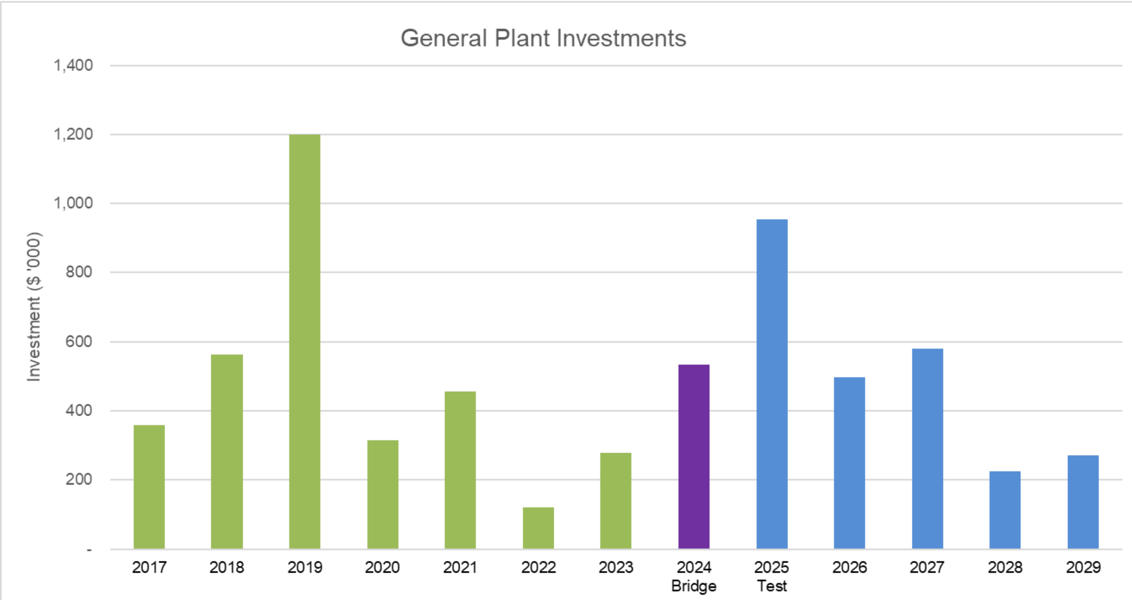


Figure 5.4-9: General Plant Expenditure Comparison

The forecast average of general plant investments in the five year forecast period is 6% higher than the historical period plus bridge year average. Fleet / rolling stock asset replacements continue, with an effort to reasonably pace these investments while sustaining asset health.

The historical period contained information system investments designed to stabilize on-premise deployments and manage recurring operating expenses over time. The forecast period information system based investments are largely aimed at asset replacements. WHESC has experienced migration of IT software to cloud platforms, moving costs to subscription based concepts in the forecast period.

Facility and fleet assessments have given WHESC valuable insight into required asset replacements in the forecast period, allowing for prioritization of projects and management investment requirements.

5.4.1.3.5 Overall

The historical and forecast overall net capital expenditures are shown in Figure 5.4-10.

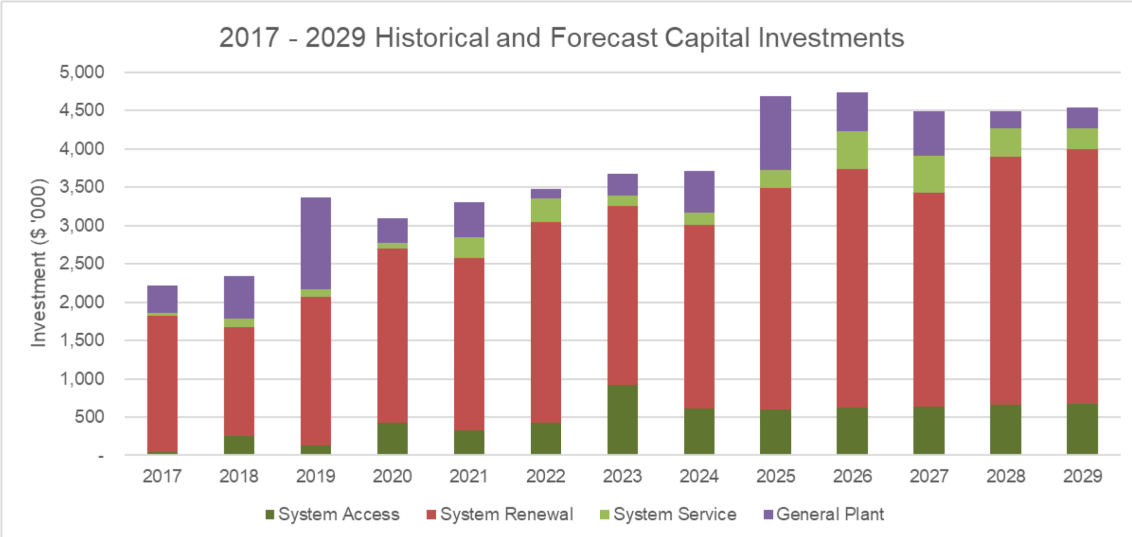


Figure 5.4-10: Overall Net Capital Expenditure Comparison

The forecast average of overall net capital investments in the five year forecast period is 44% higher than the historical period plus bridge year average. While this is notable, resource costs, capacity, and resiliency requirements have changed significantly through the historical period from 2017. With increased growth in the latter part of the historical period and the anticipation continued trend in the forecast period, there is a net impact on required capital expenditure as illustrated in the system access based investments depicted annually in Figure 5.4-10.

WHESC has listened to its customers, using feedback gleaned from engagement on preliminary investment plans to inform forecast expenditures. Feedback was generally related to WHESC's pacing of system renewal and system service based expenditures.

5.4.1.4 Important Modifications to Capital Programs Since Last DSP

One of the most important factors influencing capital expenditures that are largely based on asset renewal, is the influence of asset condition assessments. WHESC now has the benefit of two distribution system ACA cycles, which better informed historical asset management decisions, and now the requirements for the forecast period. Fleet and facility asset management decisions are now informed by those ACA results.

Grid modernization investments gained traction through the historical period as WHESC identified grid visibility and system protection philosophies that benefit system reliability and performance. With customer's reinforcing a desire for these investments, refinement of planned expenditures in the forecast period resulted.

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

Table 5.4-16 summarizes WHESC's forecast system operating & maintenance expenditures over the forecast period.

CATEGORY	Forecast Period					Total
	2025	2026	2027	2028	2029	
	$ '000	*$ '000*	*$ '000*	*$ '000*	*$ '000*	*$ '000*
System O&M	**4,705**	**4,889**	**5,063**	**5,182**	**5,336**	**25,176**

Table 5.4-16: Forecast System O&M Expenditures

With growth in customer connections, and expansion of WHESC's asset pool, there is upward pressure on system O&M increases. WHESC's intention is to manage O&M expenditures within expected incremental increases due to growth and inflation. WHESC has demonstrated this outcome throughout the historical period. The forecast expenditures are expected to achieve the same outcome.

With 67% of net capital expenditure aimed at system renewal, WHESC is investing in the replacement of assets that are most likely to cause an increase to O&M due to failure, particularly unplanned failures which are usually capitalized and therefore do not show as an improvement in O&M. As mentioned in previous sections, the majority of overhead and underground system renewal projects involve voltage conversions. This lessens the capacity requirements on WHESC's municipal substations over time, placing downward pressure on O&M.

WHESC has invested in technology to improve management of O&M expenditures. Through use of systems such as SmartMAP, informed by real time data emanating from system service based investments, WHESC can mitigate cost pressures due to premature asset failure or unstable system conditions. WHESC monitors system condition daily, reacting to power quality issues, overloaded equipment, and adverse system performance to perform mitigation and manage unplanned asset failure expenditures.

5.4.1.6 Non-Distribution Activities

There are no planned expenditures for non-distribution activities in WHESC's capital budget.

5.4.2 Justifying Capital Expenditures

WHESC's DSP delivers value to customers by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures. WHESC's customers' value system reliability and affordability. WHESC's capital plan, both historical and forecast, allows for a significant portion of investments to affect the replacement of end-of-life assets to maintain system reliability.

The planning process described in Section 5.3.1.1, is the foundation for the capital investment plan. The planning process aligns investments with WHESC's overall corporate objectives. During the development of the five year capital investment plan, a key component of WHESC's business plan, the asset management objectives are observed. As described previously, the planning process ensures that asset management objectives align with strategic goals and corporate objectives.

WHESC's planning process has resulted in a capital investment plan that:

- ensures compliance with health and safety obligations that impact the general public, our customers, and staff;
- maintains system performance, improves resiliency, and manages system operating and maintenance expenditures by managing asset health;
- minimizes the impact of WHESC's operation on the environment in which its infrastructure is deployed;
- ensures WHESC continues to meet its regulatory and legal obligations;
- addresses system capacity requirements to meet the changing needs of existing and future customers;
- improves system reliability while managing customer growth and mitigating the impacts of climate change;
- ensures that system performance is balanced with service affordability.

Shown previously, Figure 5.3-2 demonstrates how WHESC develops its capital plan. Section 5.3.1.3 describes the process of "Prioritization and Investment Selection". How this process is applied to the distinct categories of investment is described in the balance of this section. The resulting project registry showing prioritization is shown in Table 5.4-17 and Table 5.4-18.

As evidenced in Figure 5.4-10, the bulk of WHESC's planned capital investment is in the System Renewal category. The most recent ACA confirms that a good portion of WHESC's asset base is operating beyond its TUL. While asset health is used to manage the timing of replacement in conjunction with risk of failure, alignment of HI results with strategic objectives puts emphasis on sustaining the performance of WHESC's distribution assets within its system.

In addition to the ACA better informing WHESC's renewal investment decisions, WHESC has experienced expansion of its system due to growth and economic development activity. This drives non-discretionary increases in system access based investment. In the planning process, WHESC recognizes the need to modernize the operation of its distribution system such that additional exposure on the distribution system is managed. The reliability of the distribution system must continually improve while accommodating this growth, which is the basis for the identified system service investments.

The balance of this section covers the justification for WHESC's identified investment levels in each category.

System Access Investments

Generally, the need for investment stemming from external drivers has increased over the historical period based on growth and economic development activity within the City of Welland. These drivers directly tie to System Access based investments and the growth in that investment category is evident in Figure 5.4-6. In order to appropriately plan for the level of system access investment requirements, WHESC does the following:

- actively participates in developer pre-consultations on a weekly basis
- monitors active and contemplated subdivision and expansion agreements, tracking the number of pending new connections to its distribution system
- monitors changes in economic conditions to anticipate changes in customer driven demand work

System access investments are generally mandatory based on the requirement to accommodate connections to the distribution system and coordinate with third party development. Programs and projects identified in the system access category of investment are not ranked since timing of outcomes are externally driven.

System Renewal Investments

Based on ACA results, WHESC clearly needs to manage asset condition to sustain the performance of WHESC's distribution system. System reliability and resiliency are dependent on the health of WHESC's asset pool. A discretionary component of system renewal based investments is pacing. While the asset age distribution depicted in Table 5.3-8 demonstrates many assets are beyond TUL, WHESC has paced investments in this category by leveraging the HI of assets in lieu of simply age, evaluated against the failure risk.

WHESC has made strategic investments in the system service category to improve grid visibility and response to system disturbances. This assists system renewal investment pacing decisions since asset utilization and performance metrics are available and monitored in real time.

WHESC has engaged its customers to understand the appetite for increasing the pace of system renewal based investments. The majority of our customers indicate that WHESC should increase the pace of renewal investments based on bill impact and resiliency outcomes. In support of this DSP, WHESC engaged its customers to gauge the impact of a change in investment level in the two most financially significant components of system renewal investments. As indicated in Section 5.2.2.1, over half of the customers surveyed desired an increased level of investment in those categories as it relates to asset performance. This feedback was a driver of the planned system renewal investment levels.

All projects in the system renewal investment category are ranked against asset management objectives to identify execution priority. To determine the investment level in a given year, internal and strategic drivers are observed to assess:

- negative trends in performance outcomes that may require a change to investment levels;

- the required investment level to sustain the health of an asset class.

The result of this assessment drives the system renewal investment level in a particular year of the plan. Current investment levels are at or below that required to replace assets that have reached TUL over time. WHESC observes the criticality of the asset class to the reliability of the distribution system when applying this discretion.

System Service Investments

As indicated previously, system service based investments encompass WHESC's grid modernization efforts. During the historical period, these investments were designed and deployed to improve grid visibility, system reliability and disturbance response performance.

For the forecast period, the objective is to continue improving system performance while WHESC's system expands to accommodate growth. With changes related to fuel switching, EV adoption, and DER accommodation on the distribution system, these investments are required to maintain an appropriate level of visibility.

In an effort to better understand our customer's appetite for grid modernization investment, engagement in support of this DSP covered grid modernization expenditure levels. As illustrated in Figure 5.2-9, over half of WHESC's customers indicated a desire to increase investment levels to benefit system performance. That feedback has been incorporated into the system service investment levels for the forecast period.

General Plant Investments

The majority of planned investment in this category is directed towards replacement of assets at or beyond TUL. Investment levels related to management of assets classified as general plant are determined based on requirements to sustain asset health. For fleet and facilities, formal asset assessments were conducted to better inform investment level requirements.

In alignment with system renewal based decisions, WHESC understands that there is discretion in the pacing of General Plant based investments that are asset replacements. The TUL used for vehicles has been derived from WHESC's experience in managing total ownership cost based on utilization, performance monitoring, and preventative maintenance activities.

Prioritization and Selection of Investments

As described in Section 5.3.1.3, WHESC has performed analysis to prioritize planned investments and rank programs and projects against corporate goals and asset management objectives. The result of which is presented in Table 5.4-17 and Table 5.4-18.

The process involves scoring against a pre-determined criteria weight in alignment with the asset management objectives presented in Table 5.3-1. A score is assigned to each asset management objective for a particular project. The weighted scores are summed to arrive at a total score for the project or program. Projects are ranked in order of total score.

$$Score = \sum criteria\ weight\ x\ criteria\ score$$

The planning criteria, or Asset Management Objectives, are fully described in Section 5.3.1.1 and include:

- Health and Safety Performance
- Asset Performance
- Environment
- Meeting Regulatory and Legal Obligations
- System Capacity
- System Reliability
- Operational Efficiency and Affordability

The criteria weight reflects the planning criteria within WHESC decision making process, see Figure 5.3-1 for weight assignments. Asset and Health and Safety Performance have the highest weight assignment and a criteria weight of 10. The next highest weight assignments go to Environment, Regulatory and Capacity obligations with a criteria weight of eight. With weight assignment of medium, Reliability is given a criteria weight of six and Operational Efficiency a criteria weight of five.

The criteria score is assigned on a per project basis, considering the relative impact on that planning criteria if that project is not executed. The criteria score is established as follows:

- **Health and Safety Performance:**

  Those assets with a high probability of creating a safety incident, in the event of failure, received a score of 10 in this criterion. Assets with a lower potential for safety impact received a proportionally lower score.

- **Asset Performance**

  Assets that are at or beyond TUL are assessed a score of 10. The remaining assets are scored based on their remaining useful life.

- **Environment**

  Those assets with a high probability of creating a significant Environmental impact, in the event of failure, received a score of 10 in this criterion. Assets with a lower potential for Environmental impact received a proportionally lower score.

- **Meeting Regulatory and Legal Obligations**

  Those projects required to meet our Regulator and Legal Obligations, (such as Cyber Security upgrades and upgrades that support the RIP), received a score of 10 in this criterion. Projects that are not directly driven by Regulatory and Legal received a proportionally lower score.

- **System Capacity**

  Those projects that directly relate to maintaining System Capacity, received a score of 10 in this criterion. Projects that are not directly driven by maintaining System Capacity received a proportionally lower score.

- **System Reliability**

  Those assets with a high potential for a significant number of customers impacted, in the event of an asset failure (for example substation transformers and main feeders) received a score of 10 in this criterion. Those projects impacting a lesser number of customers receive a proportionally lower score.

- **Operational Efficiency and Affordability**

  Those projects with a positive cost benefit assessment, that increase operational efficiencies, receive the highest score in this criterion. Since efficiency tends to be a secondary driver, the highest score a project in this criterion received is five.

An example of the calculation for the Bishop St, McNaughton Rd Project, summed in the order of the project criteria listed above is:

- Total Score = (10x10) + (8x8) + (10x10) + (4x8) +(8x6) + (3x8) + (2x5)

  = 378

The project ranking shown in Table 5.4-17 and Table 5.4-18 summarize the calculated scores for each identified project.

Budget Year	Project Location/Program	Description	Category	Sub Category	Criteria Score							Criteria Weight							Total Score
					Asset Health	Env.	Safety	Reg.	Reliability	Capacity	Efficiency	Asset Health	Env.	Safety	Reg.	Reliability	Capacity	Efficiency	
2025	Bishop Rd, McNaughton Rd	Rebuild / Conversion 2.4KV to 16KV	System Renewal	OH	10	8	10	4	8	3	2	10	8	10	8	6	8	5	378
2025	First St, Second St	Rebuild / Conversion 2.4KV to 16KV	System Renewal	OH	10	8	10	4	8	3	2	10	8	10	8	6	8	5	378
2025	Dover Rd, Dunkirk Rd.	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	10	8	10	4	8	3	1	10	8	10	8	6	8	5	373
2025	462 Fitch Street - MS5	Replace Transformer 5T1 / HV&LV Cables	System Renewal	SUB	6	10	8	8	10	0	5	10	8	10	8	6	8	5	369
Recurring	Various	Switchgear Replacements	System Renewal	UG	10	5	10	4	10	1	3	10	8	10	8	6	8	5	355
2025	Fleet	55' Bucket Truck Replacement	General Plant	NA	10	8	8	10	2	0	3	10	8	10	8	6	8	5	351
2025	Thorold Rd, Clare Ave to Rose Ave	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	6	8	6	4	8	10	1	10	8	10	8	6	8	5	349
Recurring	Various	Transformer Replacements	System Renewal	UG	10	8	10	4	7	0	2	10	8	10	8	6	8	5	348
Recurring	Various	Pole Replacements	System Renewal	OH	10	7	10	4	8	0	2	10	8	10	8	6	8	5	346
Recurring	Grid Modernization	SCADA Device Deployments	System Service	OH	5	7	7	8	10	3	4	10	8	10	8	6	8	5	344
2025	Information Systems	VxRail Replacement	General Plant	NA	10	4	8	10	6	0	3	10	8	10	8	6	8	5	343
2025	Building Improvements	Operations Renovations	General Plant	NA	10	6	8	8	6	0	3	10	8	10	8	6	8	5	343
2025	Fleet	Reel Trailer	General Plant	NA	10	6	7	8	6	0	4	10	8	10	8	6	8	5	338
2026	M14 - Allanburg TS Tie	27.6KV Extension / Tie	System Service	OH	0	3	7	10	10	10	4	10	8	10	8	6	8	5	334
2026	Clare Ave, Fitch St to Thorold Rd	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	7	6	6	4	6	10	1	10	8	10	8	6	8	5	331
2026	Lincoln St, Plymouth to King	Rebuild / 27.6KV Extension	System Renewal	OH	8	6	10	4	6	3	2	10	8	10	8	6	8	5	330
2026	McArthur Ave, Morningstar Ave, Coventry Rd	Rebuild / Conversion 2.4KV to 16KV	System Renewal	OH	8	6	10	4	6	3	1	10	8	10	8	6	8	5	325
2026	Information Systems	SCADA Firewall/Switch Replacements	General Plant	NA	10	4	9	10	2	0	2	10	8	10	8	6	8	5	324
2027	First Ave, Woodlawn to Quaker	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	6	7	6	4	5	10	1	10	8	10	8	6	8	5	323
2027	M19 - Allanburg TS Tie	27.6KV Extension / Tie	System Service	OH	0	3	7	10	9	9	4	10	8	10	8	6	8	5	320
2027	Leonard Ave, Donna Marie Dr	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	8	6	10	4	5	3	1	10	8	10	8	6	8	5	319
2027	Summit Ave, Linwood Dr, Rosemount Dr, Home St	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	8	6	10	4	5	3	1	10	8	10	8	6	8	5	319
2027	397 Fitch Street - MS7	Replace Transformer 7T1 / HV&LV Cables	System Renewal	SUB	7	10	7	4	10	0	1	10	8	10	8	6	8	5	317
2027	Fleet	55' Bucket Truck Replacement	General Plant	NA	7	7	8	10	2	0	3	10	8	10	8	6	8	5	313

Table 5.4-17: Prioritized Projects 2025-2027

Budget Year	Project Location/Program	Description	Category	Sub Category	Criteria Score							Criteria Weight							Total Score
					Asset Health	Env.	Safety	Reg.	Reliability	Capacity	Efficiency	Asset Health	Env.	Safety	Reg.	Reliability	Capacity	Efficiency	
2028	St Andrews Ave, Hagar Street, Garon Ave	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	10	6	7	4	5	3	1	10	8	10	8	6	8	5	309
2028	Erin Cres, Steven St	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	6	6	7	4	8	5	2	10	8	10	8	6	8	5	308
2028	Sharon Ave, Walt St	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	6	6	7	4	8	5	2	10	8	10	8	6	8	5	308
2028	King St, Regent St to Lincoln St	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	7	5	6	4	8	5	3	10	8	10	8	6	8	5	305
2028	Lyons Creek Rd, Darby Rd	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	10	5	9	4	6	0	1	10	8	10	8	6	8	5	303
2028	State St, Kent St, Albet St	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	8	5	7	4	6	5	1	10	8	10	8	6	8	5	303
2028	Lincoln St, Conventry Rd to McAlpine Rd	27.6KV Extension / Tie	System Service	OH	3	4	6	4	6	10	5	10	8	10	8	6	8	5	295
2028	Fleet	Wheeled Loader Replacement	General Plant	NA	8	5	6	10	0	0	5	10	8	10	8	6	8	5	285
2029	Northgate Dr	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	6	4	9	4	6	3	1	10	8	10	8	6	8	5	279
2029	Glenwood Pky, Crescent Dr, Richmond St, Springfield St	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	8	4	6	4	6	3	1	10	8	10	8	6	8	5	269
2029	Quaker Rd, First Ave to Niagara St	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	6	4	3	4	4	10	2	10	8	10	8	6	8	5	268
2029	Building Improvements	North Yard Gate - Security Hardning	General Plant	NA	5	8	7	7	0	0	3	10	8	10	8	6	8	5	255
2029	Apple Cres, Brant Ave	Rebuild / Conversion 2.4KV to 16KV	System Renewal	UG	6	4	7	4	4	3	2	10	8	10	8	6	8	5	252
2029	East Main St, Myrtle Ave to Scholfield Ave	Rebuild / Conversion 4.16KV to 27.6KV / Tie	System Renewal	OH	6	3	6	4	6	3	2	10	8	10	8	6	8	5	246
2029	Ontario Rd, Memorial Park Dr to Hydro Corridor	Rebuild / Conversion 4.16KV to 27.6KV	System Renewal	OH	6	4	5	4	6	2	3	10	8	10	8	6	8	5	241
2029	Glenayr Pl, McColl Dr, Briarfield Cres	Rebuild 2.4KV	System Renewal	UG	6	4	7	4	4	0	2	10	8	10	8	6	8	5	228

Table 5.4-18: Prioritized Projects 2028-2029

5.4.3 Material Investments

The materiality threshold used in the 2025 COS that this DSP supports, is $68K. Using the process described in Section 5.3.1.3, WHESC has ranked and prioritized its material investments resulting in the test year investments identified in Table 5.4-19.

Category	Program	Project	Score	Project Rankiing	2025 Planned Expenditure ($ '000)
System Access	General Services	N/A	N/A	N/A	240
	Subdivisions	N/A	N/A	N/A	1,136
	Meters	N/A	N/A	N/A	155
System Renewal	Substation Renewal	MS 5 TX Replacement, HV / LV Cables	369	4	330
	Overhead Line Renewal	Bishop Rd, McNaughtion Rd - Rebuild / Voltage Conversion	378	1	300
		First St, Second St - Rebuild / Voltage Conversion	378	2	250
		Thorold Rd, Clare Ave to Rose Ave - Voltage Conversion	349	7	500
	Underground System Renewal	Dover Rd, Dunkirk Rd - Rebuild / Voltage Conversion	373	3	550
		Switchgear Replacement	355	5	258
	Pole Replacement	N/A	346	9	302
	Transformer Replacement	N/A	348	8	161
	Reactive OH System Replacement	N/A	N/A	N/A	151
System Service	Grid Modernization	SCADA Device Deployment	344	10	242
General Plant	Information Systems	Computer Hardware	343	11	120
	Fleet	55' Bucket Truck	351	6	529
		Reel Trailer	338	13	85
	Building Improvements	Operations Renovations	343	12	125
Gross Capital Expenditure - Material Projects in the Test Year					**5,434**
Gross Capital Expenditure - All Projects in the Test Year					**5,658**

Table 5.4-19: Programs/Projects Over Materiality During Test Year

For each of these programs or projects, a detailed narrative highlighting investment drivers, analysis, and justification, is provided in Appendix 5-A.

Appendices

Appendix 5-A: Material Project Narratives

Appendix 5-B: Integrated Regional Resource Plan

Appendix 5-C: Customer Engagement Survey Workbook

Appendix 5-D: Customer Engagement Survey Results

Appendix 5-E: Regional Infrastructure Plan

Appendix 5-F: REG Investment Plan

Appendix 5-G: IESO Letter of Comment

Appendix 5-H: Asset Condition Assessment (2023)

Appendix 5-I: Fleet Assessment

Appendix 5-A: Material Project Narratives

A. General Information on the Program / Project

1. Overview

This program consists of capital expenditures related to requests for service upgrades or the connection of new services for non-residential customers and is non-discretionary work. WHESC has an obligation to connect these customers in accordance with the Distribution System Code (DSC) and WHESC's Conditions of Service. The volume of work associated with this program varies annually, with WHESC experiencing growth in these connection expenditures in recent years.

The scope of work required to complete the connection is dependent on the proposed location within WHESC's service territory. In many cases connections can be completed requiring minimal distribution systems upgrades, while in other cases upgrades are required in order to facilitate service to the customer. Upgrades include but are not limited to pole replacements, transformer replacements, new transformer installations and system expansion. If a system expansion is required, a separate system access project will be prepared.

WHESC's new or upgraded general service connections for the historical period are included in the table below. As the table shows, WHESC has facilitated an average of 22 new or upgraded connections on an annual basis over the historical period. The volume of new or upgraded connections has increased annually and WHESC anticipates this trend to continue.

Year	Number of New Connections
2017	15
2018	13
2019	24
2020	32
2021	29
2022	21
2023	31

2. Timing

a) Beginning: January 2025

b) In-Service: Through to December 2029

c) Key factors that may affect timing: The program schedule is driven by customer requests, which can be unpredictable. The timing of execution is heavily dependent on when the customer initiates their request.

3. Historical and Future Capital Expenditures

CATEGORY	Historical Period							Bridge	Forecast				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2025	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
General Services	19	11	88	151	59	109	227	233	240	247	254	262	270
Capital Contributions	- 2	- 26	- 75	- 119	- 27	- 102	- 139	- 143	- 147	- 152	- 156	- 161	- 166
Net Capital Expenditure	17	- 14	12	31	33	7	88	90	93	95	98	101	104

4. Economic Evaluation

Economic evaluations are generally not applicable for new general services where the bulk of required infrastructure consists of connection assets. If an expansion of the distribution system is required to facilitate the connection, economic evaluations are completed in accordance with the DSC.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs for this program. The quantity and scope of requests made by customers varies year to year, WHESC considered the historical expenditure, projected growth and known development activity to produce the forecast under this program.

Changes in accounting practices resulted in inconsistencies throughout the historical period.

6. Investment Priority

General service connections are non-discretionary investments, driven by customer requests. WHESC is obligated to facilitate the requested connections in order to meet our regulatory requirements under the DSC and WHESC's Conditions of Service. These types of projects are balanced against other mandatory system access programs but take precedence over other discretionary programs.

7. Alternative Analysis

Alternatives are considered on a case-by-case basis for each connection request. Multiple servicing methods may be reviewed, each having their own potential advantages and disadvantages. Additional factors that are considered include safety, economics, regulatory compliance, system reliability and customer value to develop the most effective solution.

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 and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	General service installations are designed and constructed as per WHESC's standards and specifications to serve customers in the most efficient and cost-effect manner.
Customer Value	Customers benefit from access to safe and reliable electricity. WHESC continues to make great efforts to ensure that all reasonable steps are taken to ensure regulated timelines for new connections are met.
Reliability	This program will have a negligible effect on reliability as there is a low probability of premature failures with new equipment.
Safety	Construction is in accordance with WHESC's specifications, Utility Standards Form (USF) standards, Canadian Standards Associations (CSA) standards, Ontario Regulation 22/04 and Grid Smart City (GSC) specifications.

2. Investment Need

Primary Driver:

Regulatory – This program is externally driven by customer demand and is required for regulatory compliance.

Secondary Driver:

Strategic Objectives – This program aligns with WHESC's mission to distribute safe, reliable power that enhances the quality of life in our service area.

Information Used to Justify the Investment:

Connection volumes for new or general service upgrade requests are forecasted based on historical expenditure trends, growth projections and in consultation with the City of Welland and customers. Further information can be found in Section 5.2.2 of the DSP.

3. Investment Justification

Demonstrated Utility Practice:

All new general services are designed and constructed to the latest safety standards and specifications.

Cost-Benefit Analysis:

All projects within the program are reviewed with the customer and their consultants to determine the most cost-effective method of providing service. This ensures design and construction is completed to the latest standards, specifications, and system requirements in order to provide system flexibility under normal and emergency conditions.

Historical Outcomes

The quantity and related expenditure of general services connected during the historical period are detailed within Sections 1, 3 and 5 in Part A of this document. WHESC's continues to facilitate general service connections as required by our regulatory obligations.

4. Conservation and Demand Management

CDM is not applicable for this program.

5. Innovation

This is not applicable.

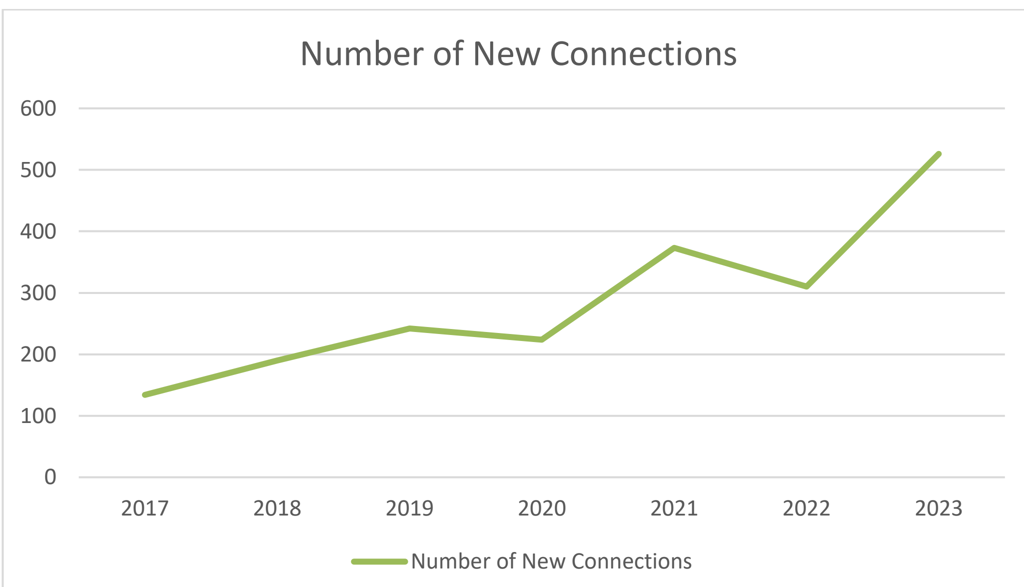
A. General Information on the Program / Project

1. Overview

This program consists of capital expenditure in response to requests from property developers wishing to construct new residential subdivisions and is non-discretionary work. This program requires the installation of underground distribution infrastructure including civil work, vaults, primary cables, secondary cables, transformers, terminations, and associated riser hardware.

WHESC new subdivision connections for the historical period are included in the table below. As the table shows WHESC has connected an average of 285 of new services over the historical period, with a significant increase in the number of new connections for the years 2021 to 2023.

Year	Number of New Connections
2017	134
2018	190
2019	242
2020	224
2021	373
2022	310
2023	526



2. Timing

d) Beginning: The timing and schedule of projects within this program are determined by the developers and their consultants. WHESC maintains active communications with the developers and consultants to ensure WHESC remains aware of forecasted timing within each budget year.

e) In-Service: 2025-2029

f) Key factors that may affect timing: The program schedule is dictated by the requirements of developers and is largely outside of WHESC's control.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Subdivisions	-	189	298	1,313	681	472	1,187	1,103	1,136	1,170	1,205	1,242	1,279
Capital Contributions	-	145	267	1,003	503	194	852	803	827	852	878	904	931
Net Capital Expenditure	-	44	31	310	178	278	335	300	309	318	328	338	348

4. Economic Evaluation

Economic Evaluations are completed in accordance with the Distribution System Code and the corresponding Subdivision Agreement for each new subdivision expansion project within WHESC's service territory.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs for this program. The quantity and scope of projects within this program varies from year to year.

6. Investment Priority

Subdivision projects are non-discretionary investments driven by developers. WHESC is obligated to facilitate the requested connections in order to meet our regulatory requirements under the DSC and WHESC's Conditions of Service. These types of projects are balanced against other mandatory System Access programs but take precedence over other discretionary programs.

7. Alternative Analysis

Alternatives are considered on an individual basis for each connection request considering safety, economics, regulatory compliance, system reliability and customer relations to develop the most effective solution. Subdivision developments are driven by developers and are a non-discretionary investment.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	Subdivision installations are designed and constructed as per WHESC's standards and specifications to serve customers in the most efficient and cost-effect manner. Where appropriate, customers complete design using their own consultants.
Customer Value	Customers benefit from access to safe and reliable electricity. WHESC continues to make great efforts to ensure that all reasonable steps are taken to ensure regulated timelines for new connections are met.
Reliability	This project will have a negligible effect on reliability as there is a low probability of premature failures with new equipment when constructed to WHESC standards.
Safety	Construction is in accordance with WHESC's specifications, Utility Standards Form (USF) standards, Canadian Standards Associations (CSA) standards, Ontario Regulation 22/04 and Grid Smart City (GSC) specifications.

2. Investment Need

Primary Driver:

Customer Service Requests – This program requires the expansion of the electrical distribution system in order to facilitate new connections.

Secondary Driver:

Mandated Service Obligations – This program is primarily driven by developer demand and therefore falls under WHESC's regulatory compliance as stated within the DSC and WHESC's Conditions of Service.

Information Used to Justify the Investment:

Developer initiated requests for new connections are budgeted based on historical expenditure trends, growth projections and consultations with the City of Welland. Further information can be found in Section 5.2.2 of the DSP.

3. Investment Justification

Demonstrated Utility Practice:

Subdivision projects are executed in accordance with relevant regulatory requirements. Installations comply with the latest safety standards and specifications.

Cost-Benefit Analysis:

All projects within the program are reviewed with the developers and their consultants to determine the most cost-effective method of servicing, while ensuring design and construction are completed to the latest standards, specifications, and system requirements in order to provide system flexibility under normal and emergency conditions.

Historical Outcomes

The historical costs and number of Subdivisions connected during the historical period are detailed within sections 1,3 and 5 in Part A of this document. WHESC's continues to facilitate Subdivision connections as required by our regulatory obligations.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This program consists of capital expenditures related to the supply, installation, and maintenance of retail meters for the purpose of retail settlement and billing purposes. The program ensures WHESC accurately measures and bills customers for the electricity that they utilize. Replacement of failed meters and the process of compliance testing and resealing are included within this program as per Measurement Canada requirements. WHESC completes meter sampling and reverification in compliance with Measurement Canada requirements to extend the life of existing meter assets.

WHESC owns, operates, and maintains 25,753 retail meters installed on customers' premises which measure electricity usage and demand. Deployment of retail "smart" meters began in 2009, following the government legislation and continues to date. WHESC replaces on average 159 failed meters per year. Based on current failure rates; full replacement of existing meters is not deemed required at this present time.

Year	Number of Failed Meters
2017	225
2018	108
2019	150
2020	160
2021	127
2022	190
2023	153

2. Timing

g) **Beginning:** January 2025

h) **In-Service:** Through to December 2029

i) **Key factors that may affect timing:** The program schedule is dictated by new customer connections, meter failures and meter reverification. Additional key factors include procurement of labour and materials, restricted access and unforeseen issues with third party meter testing providers.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	73	182	63	48	178	111	315*	150	154	159	163	168	173
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	73	182	63	48	178	111	315	150	154	159	163	168	173

*See Section 5

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs for this program. WHESC considered the historical expenditure, forecasted failures, projected growth and supply chain factors to produce the forecast under this project.

In 2023, WHESC increased meter stock due to significant post-COVID lead times at a cost of $165K.

The year over year variance in 2018 is largely due to MIST metering replacements.

6. Investment Priority

Metering investments are non-discretionary investments driven by mandatory obligations to connect customers and maintain billing accuracy as detailed within the DSC and Measurement Canada requirements. Meter projects are balanced against other mandatory System Access programs but take precedence over other discretionary programs.

7. Alternative Analysis

Metering investments are non-discretionary. Failure to complete installation, maintenance and replacement of metering assets would be in violation of the DSC and Measure Canada requirements.

WHESC performs compliance sampling where an existing meter population demographic meets Measurement Canada requirements. WHESC reviewed the alternative of replacing all meters in sample group populations with new meters. This was not chosen due to the low failure rates currently being experienced within WHESC's meter population. The necessity to manage total capital expenditures and the technological capability of existing residential meters, supporting real time data analytic requirements, has driven WHESC to maintain the existing fleet of meters.

8. Innovative Nature of the Project

WHESC found no innovative elements within this project.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	WHESC utilizes standard designs and materials to produce efficiencies within the process. Replacement of legacy assets promotes standardization and improves inventory management. WHESC utilizes smart meter data for additional purposed such as service monitoring, transformer loading and outage monitoring. This additional information is used to gain efficiencies when completing capital renewal projects and restoring outages.
Customer Value	Customers benefit from the ability to view their usage and choose the billing rate that best suits their needs. Upgrading and renewing existing meters are required, ensures WHESC captures accurate electricity usage to produce an accurate bill.
Reliability	WHESC uses smart meter data for real time outage monitoring. This information assists WHESC to determine the outage location and improve system reliability. Renewal of metering assets ensures the reliability of the meters themselves continues, enabling a reliable source of billing data.
Safety	All meter installations are completed to the latest safety standards.

2. Investment Need

Primary Driver:

Mandated Service Obligations – This program is primarily driven by WHESC's obligations to install, operate and maintain metering assets as defined within the DSC and Measurement Canada requirements.

Secondary Driver:

Customer Service Requests – This program includes the installation and replacement of retail meters for residential and commercial customers and ensures WHESC meets its service requirements as defined within the DSC and WHESC's Conditions of Service.

Information Used to Justify the Investment:

New meter purchases are budgeted based on historical expenditure trends, growth projections and reverification requirements.

3. Investment Justification

Demonstrated Utility Practice:

All new metering purchases and installations comply with the latest safety standards and regulations. Meter purchases and replacements are driven by Measurement Canada requirement.

Cost-Benefit Analysis:

A cost-benefit analysis was completed to determine whether to continue reverification of existing meters for another sample period or to holistically replace aged assets. WHESC determined that continuing with reverification was of a greater benefit at this present time.

Historical Outcomes

The historical costs and number of subdivisions connected during the historical period are detailed within Sections 3 and 5 in Part A of this document. WHESC's continues to meet customer requirements for new connections, regulatory requirements and accurately measure and bill customers.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

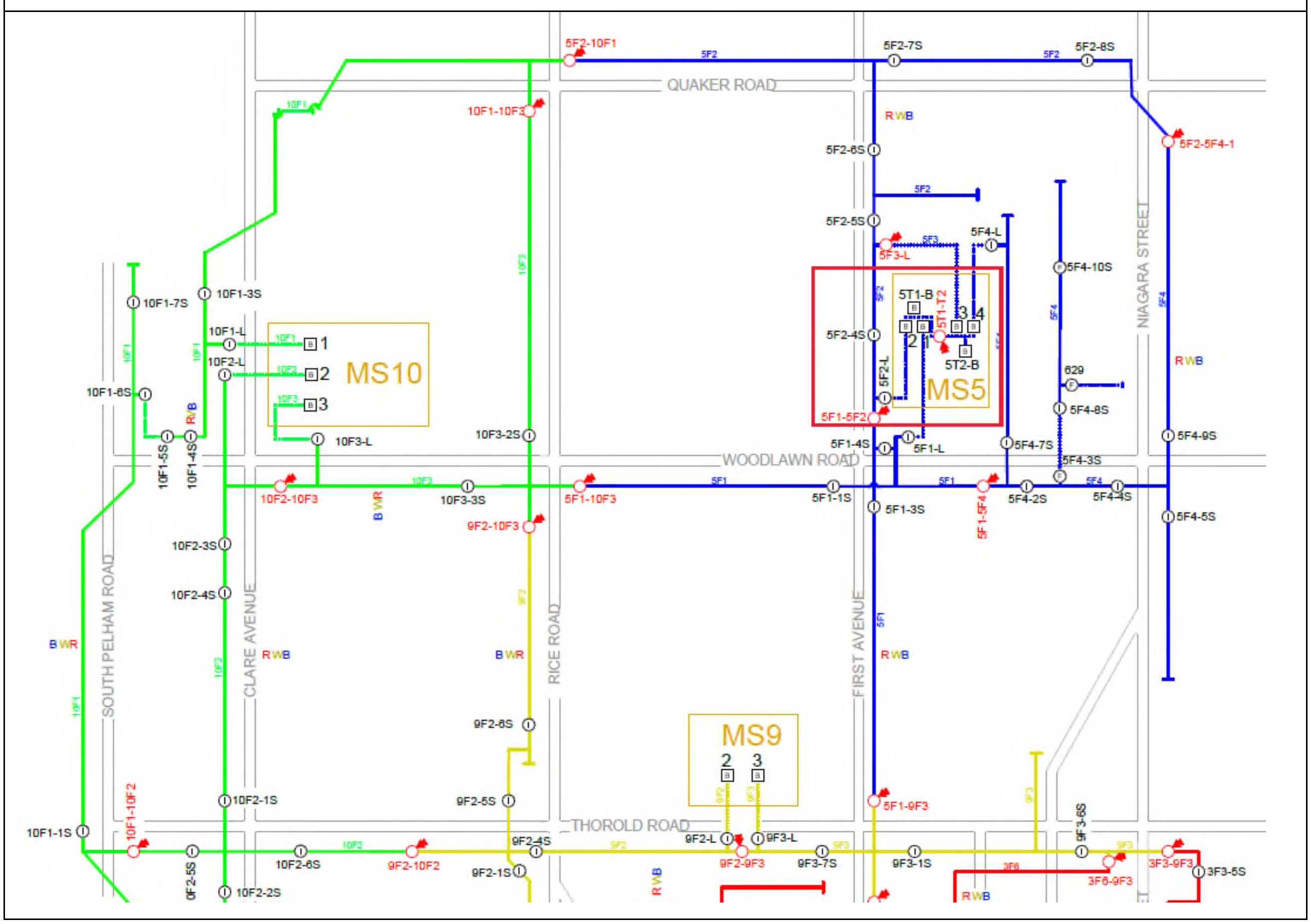
A. General Information on the Program / Project

1. Overview

This project consists of capital expenditures related to the replacement of substation transformer 5T1, associated high voltage cables and terminations. WHESC's Asset Condition Assessment (ACA) indicates that the noted transformer is currently in "very good' condition, however independent third-party testing has indicated high levels of moisture ingress and dielectric strength below acceptable limit. Due to the relatively high project maintenance costs, and the risk of accelerated degradation due to the unit's age, it has been determined that the best course of action is to pro-actively replace the noted unit. MS 5 is a critical substation that supplies approximately 1300 customers and provides redundancy for adjacent substations MS9 and MS10.

The existing 5T1 transformer is a 5MVA unit with a peak demand of 4.2MW in 2023. MS 5 houses a second substation transformer 5T2, which is rated at 4MVA and had a peak demand of 2MW in 2023. The peak loading data shows that by balancing the load between 5T1 and 5T2, WHESC will be able to replace the existing 5MVA unit with a smaller 4MVA unit that is a standard model used at equivalent WHESC substations. Use of a standard substation transformer model throughout the system, when possible, streamlines the installation process and allows for greater flexibility within the system in emergency situations. Additionally, installing a pad-mounted type substation transformer allows for the permanent removal of the existing metal-clad switchgear.

WHESC 4.16KV Operating Map



Existing 5T1	Example of New 5T1
	

2. Timing

a) **Beginning:** Q3 2025

b) **In-Service:** Q4 2025

c) **Key factors that may affect timing:** Project execution may be impacted by material procurement delays. Additionally, execution may be impacted by unplanned and/or higher priority work arising that may cause resource constraints.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	324	199	307	203	33	758	-	-	360	-	300	-	-
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	324	199	307	203	33	758	315	-	360	-	300	-	-

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs for equivalent projects. WHESC forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. Historical costs noted in Section 3 are a summary of costs within this accounting code and do not directly relate to the cost of this project.

6. Investment Priority

Using the prioritization process outlined in section 5.3 of the DSP, this project has a priority ranking of four. In order to maintain system integrity and reliable service to customers, WHESC plans to replace the noted critical substation assets. If not replaced the noted assets will continue to deteriorate which may lead to an increase in outage frequency and duration. Asset failure will also limit WHESC's ability to provide redundancy for adjacent substations and impact contingency plans.

7. Alternative Analysis

a) **Do nothing/run to fail approach:** The do nothing / run to fail approach is not a viable option. The existing infrastructure has reached TUL and the risk of failure is high due to the number of customers that will be directly affected.

b) **Elimination of substation via voltage conversion:** The costs associated with converting all downstream infrastructure from 2.4/4.16kV to 16/27.6kV greatly exceeds the cost-benefit of the proposed plan.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	The proactive replacement of the noted station infrastructure that has reached end of life will greatly decrease the probably and impact of failure in this distribution area. Use of a standard substation transformer model, constructed to a lower loss rating, streamlines the installation process.
Customer Value	The renewal of this infrastructure will have the following benefits: reduction of potential risk of failure and duration of outage; avoidance of emergency repairs that will require a long duration which in turn impacts the customers day-to-day life.
Reliability	Removing legacy infrastructure and installing standardized materials, utilizing current design standards will assist with maintaining reliability levels.
Safety	Removing legacy infrastructure and installing standardized materials, utilizing current design standards will improve safety for WHESC staff. The existing transformer has a higher than normal environmental risk due to its construction (cooling fins and sudden pressure relief vent) and potential for oil spill in the event of failure.

2. Investment Need

Primary Driver:

Failure Risk – The focus of this project is to replace aged critical substation assets due to the high cost, risk, and outcome of a failure. A failure of critical infrastructure can lead to an extended outage and costly restoration expenditure.

Secondary Driver:

Reliability – The project will replace legacy infrastructure that is not constructed to current standards and is beyond its TUL. The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability.

Information Used to Justify the Investment:

WHESC's asset management process (Section 5.3 of the DSP), incorporated with our ACA and project prioritization determined the scheduling of this investment. The planned replacements in this project ensure that WHESC continues to mitigate risk and maintains a safe electrical system.

3. Investment Justification

Demonstrated Utility Practice:

All new installations comply with the latest safety standards and regulations.

Standards and construction are completed as per the requirements of CSA 22.3 No.1 Overhead Systems and CSA 22.3 No.7 Underground Systems.

WHESC is a member of the Utilities Standards Form (USF) and uses the USF standards, in conjunction with WHESC internally developed standards. The use of USF standards harmonizes design and construction of WHESC projects with all other USF members.

Design and construction are completed in compliance with the requirements of Ontario Regulation 22/04 (Reg 22/04). During the historical period, WHESC has maintained compliance with Reg 22/04 and this planned program will ensure WHESC can continue to be compliant over the course of the forecast period.

Cost-Benefit Analysis:

All projects are reviewed to determine the most cost-effective method of completion, while ensuring design and construction are completed to the latest standards, specifications, and system requirements in order to provide system flexibility under normal and emergency conditions. WHESC reviewed alternative options within section 7 in part A of this document and found no other practical, cost-effective alternative that provides the same level of benefits to customers.

Historical Outcomes

The historical costs of equivalent projects completed during the historical period are detailed within Sections 3 and 5 in Part A of this document. WHESC has completed several similar transformer replacement projects historically and has observed many positive outcomes. These include but are not limited to improved safety for WHESC staff, cost avoidance with regards to emergency outage and restoration, and mitigation of large-sale outages due to failures of critical infrastructure based on proactive replacements.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

There are three projects associated with a contiguous area targeted for rebuild and voltage conversion. Of the three projects, two are classified under the Overhead System Renewal Program based on the majority of replacement assets consisting of poles and wires. These are as follows:

- **Bishop Rd., McNaughton Rd. – Rebuild / Voltage Conversion (Ranked #1)**
- **First St., Second St. – Rebuild / Voltage Conversion (Ranked #2)**

The third project is classified under the Underground System Renewal Program based on the majority of replacement assets consisting of cable and pad-mounted equipment. This project is as follows:

- **Dover Rd., Dunkirk Rd. – Rebuild / Voltage Conversion (Ranked #3)**

These projects require capital expenditures to replace deteriorated rear lot assets, perform voltage conversion from the 4.16kV to 27.6kV system, and remove restricted conductors from service. WHESC's distribution system consists of primary distribution at voltages of 4.16kV and 27.6kV. Historically, residential load was placed on the 4.16kV system, whereas the 27.6KV system was operated as "sub-transmission", used to supply 4.16kV substations and commercial customers. Due to this approach, the amount of 4.16kV distribution is significant in WHESC's system. When cost feasible, WHESC will convert load from the 4.16kV system to the 27.6kV, while ensuring existing 4.16kV substation feeder interties remain. Maintaining loop-fed redundancy across WHESC's fleet of 13 substations is necessary to maintain reliability during normal and emergency operating conditions. The conversion to 27.6kV will result in lower line losses over time.

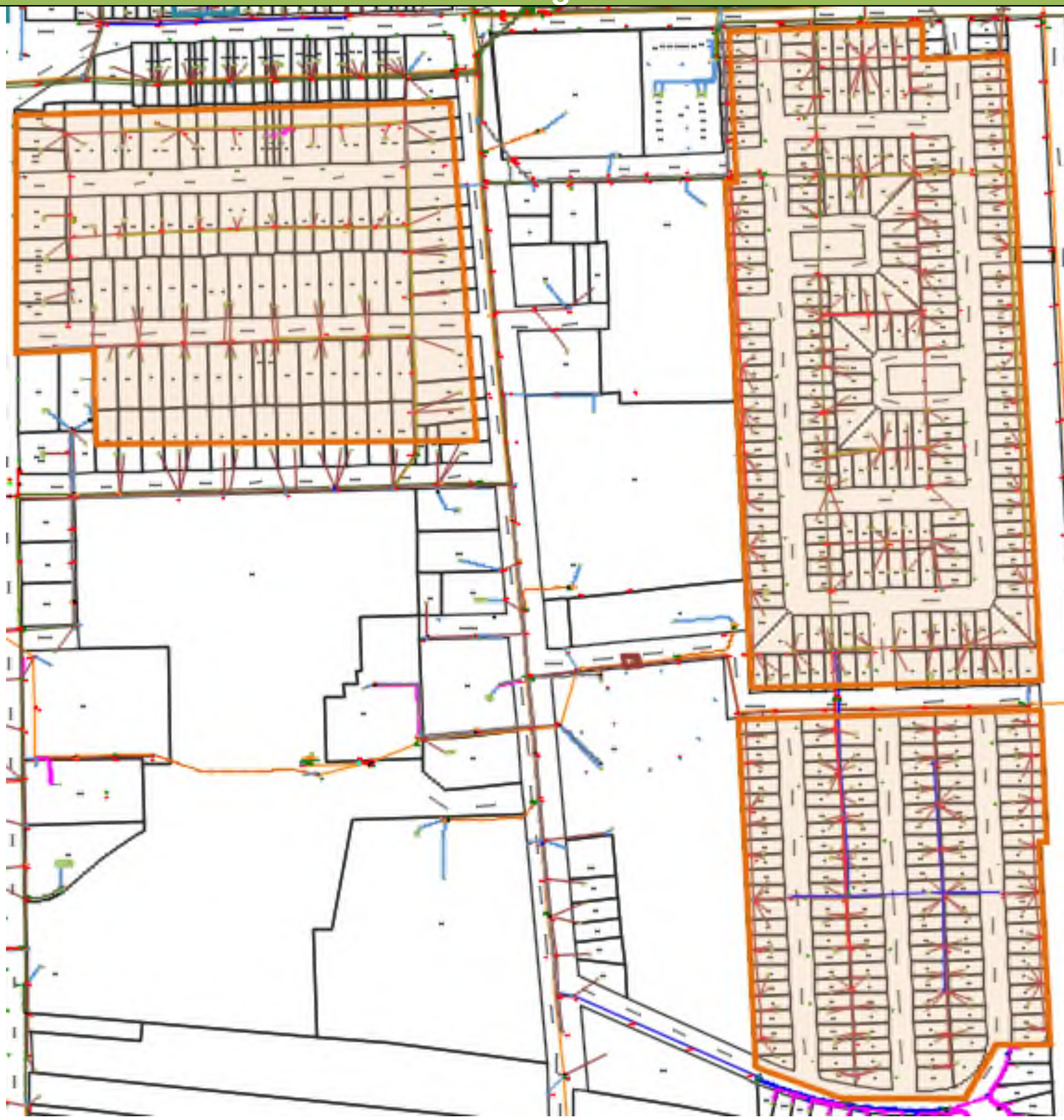
During the 1960's rear lot construction was the preferred method of construction. Rear lot construction included the placement of poles, conductors, and transformers within customer owned properties, typically on the lot line between two parcels. Difficulties arise over time when maintaining and/or replacing rear lot infrastructure due to access restrictions. Replacement of rear lot assets requires an increased in effort when compared to road accessible assets. Work methods primarily include climbing and / or the use of equipment designed for rear-lot access. The performance of rear lot distribution systems is affected by tree encroachment. Private homeowners do not typically maintain trees in the manner that municipal entities do within a road allowance. WHESC maintains a proactive tree trimming program throughout its system to mitigate tree clearances based on ESA guidelines, however, maintenance of privately owned trees remains the responsibility of the property owner.

The installation of both #6 copper and #4 ACSR primary conductors was also popular during the 1960's. There have been several documented incidents, involving Ontario LDC's, related to working on or in proximity to #6 copper and #4 ACSR primary conductors. The age of these conductors in combination with over-tensioning, small strand size, long spans and poor quality of their original manufacturing appear to be contributing factors to the breakage of these conductors. WHESC follows these restrictions when working on or in proximity to restricted conductors:

- No live line work shall be performed on restricted conductors,
- Work which significantly alters the strain on the pole shall be considered hazardous and an outage must be taken,
- No work shall be performed within the restricted zone as defined in the Electrical Utility Safety Rules, unless the work being performed offers no risk to the hazardous conductor or worker. If a safe work environment cannot be maintained, an outage must be taken.

This projects under this program include the removal of overhead primary infrastructure (transformers, conductors and switches) from rear lot and replacement with assets in the municipally owned road allowance. The installation of both new overhead infrastructure and underground infrastructure are utilized depending on the existing municipal boulevard conditions. Factors that determine the category of replacement system include but are not limited to tree density and the available space within the road allowance. WHESC reviews the project areas on a case-by-case basis to determine the optimal installation type (overhead vs. underground) to limit the overall disturbance to the established neighborhoods. Enhanced public safety is achieved through the relocation of utility assets from rear lot to the municipal road allowance.

Overall Program Area



*Project areas are shown in orange.

Project #1: Bishiop/ McNaughton

*Project area is shown in orange.

Major Assets Impacted:

Assets identified below are shown with quantity. The quantity of assets has been identified as those requiring replacement or refurbishment as part of this project and was determined by the project type and project scope. In this area, most of the replacement assets are classified as overhead. These assets directly or indirectly impact the total expenditure required by this project.

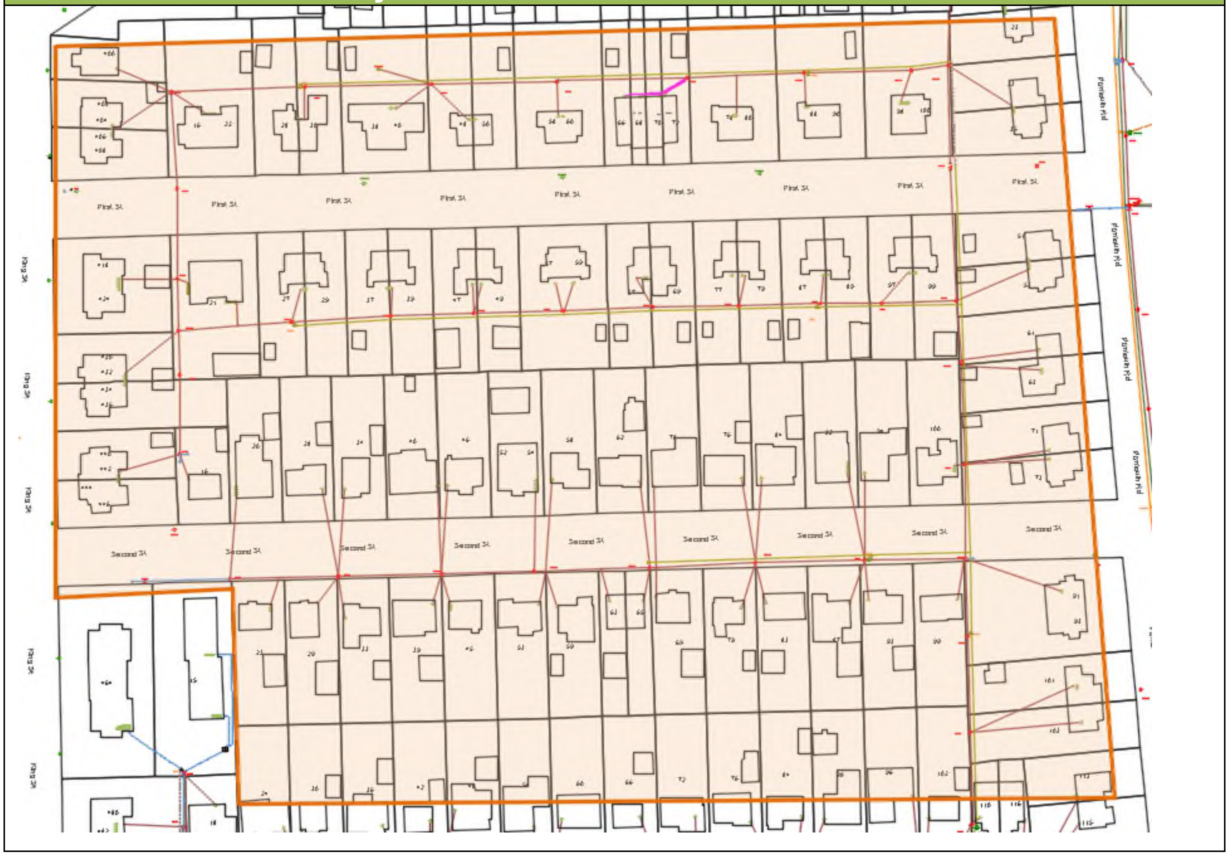
Poles		
Location	**Quantity**	**Average Age**
Rear Lot Poles	36	40
Street Front Poles	0	0

Transformers			
Type	**Quantity**	**Total KVA**	**Average Age**
1-Phase	6	350	24
3-Phase	0	0	0

Conductor		
Type	**Quantity (m)**	**Average Age**
1-Phase Overhead	687.5	54
3-Phase Overhead	0	0
1-Phase Underground	0	0
3-Phase Underground	0	0

Restricted Conductor (m)	639.9

Project #2: First St / Second St



*Project area is shown in orange.

Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets has been identified as those requiring replacement or refurbishment as part of this project and was determined by the project type and project scope. In this area, most of the replacement assets are classified as overhead. These assets directly or indirectly impact the total expenditure required by this project.

Poles		
Location	**Quantity**	**Average Age**
Rear Lot Poles	38	53
Street Front Poles	0	0

Transformers			
Type	**Quantity**	**Total KVA**	**Average Age**
1-Phase	6	287.5	49
3-Phase	0	0	0

Conductor		
Type	**Quantity (m)**	**Average Age**
1-Phase Overhead	836	62
3-Phase Overhead	0	0
1-Phase Underground	0	0
3-Phase Underground	0	0

Restricted Conductor (m)	835

Project #3: Dover Rd, Dunkirk Rd

*Project area is shown in orange.

Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets has been identified as those requiring replacement or refurbishment as part of this project and was determined by the project type and project scope. In this area, most of the replacement assets are classified as underground. These assets directly or indirectly impact the total expenditure required by this project.

Poles		
Location	**Quantity**	**Average Age**
Rear Lot Poles	32	50
Street Front Poles	0	0

Transformers			
Type	**Quantity**	**Total KVA**	**Average Age**
1-Phase	11	525	49
3-Phase	0	0	0

Conductor		
Type	**Quantity (m)**	**Average Age**
1-Phase Overhead	928	71
3-Phase Overhead	568	71
1-Phase Underground	0	0
3-Phase Underground	0	0

Restricted Conductor (m)	413

2. Timing

j) Beginning: Beginning January 2025

k) In-Service: Through to December 2029

l) Key factors that may affect timing: Project execution may be impacted by the ability to procure labour and materials in alignment with schedule. Additionally, execution may be impacted by unplanned and/or higher priority work arising that may cause resource constraints.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	-	-	-	-	-	-	-	-	1,100	1,440	570	360	380
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	-	-	-	-	-	-	-	-	1,100	1,440	570	360	380

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Rear lot conversion is a new program to WHESC. Forecast expenditures are based on historical actuals and the required scope for each project, with increases applied to materials and labour to account for inflation.

6. Investment Priority

Using the prioritization process outlined in Section 5.3 of the DSP. The projects included within this program have a priority ranking of 1,2 and 3 out of 40. In order to maintain system integrity and reliable service to customers, WHESC plans to replace the noted rear lot infrastructure. If not replaced these assets will continue to deteriorate which may lead to an increase in outage frequency and duration.

7. Alternative Analysis

a) Do nothing/run to fail approach: The do nothing / run to fail approach is not a viable option. The existing infrastructure has reached end of life and a high risk of failure is high due to location.

b) Replace assets in place: Replacing assets in place is not a viable option. The replacement cost will be far greater due to the restricted access and required work methods. The hazards associated with rear lot primary distribution would remain.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	The proactive replacement of the noted infrastructure that has reached end of life, will greatly decrease the probably of failure in this distribution area. Relocating primary assets to the accessible road allowance will increase the efficiency of WHESC staff when performing daily and emergency response. The assets are approaching end of life and replacement will be required. Planned programs are more efficient than reactive replacements due to efficiencies of scale and the ability to modernize standards.
Customer Value	Customer will receive value from future lower line losses due to the higher operating voltage as well as the increased capacity to service new and/or increased existing loads via the 27.6KV infrastructure. The renewal of this infrastructure will have the following benefits: reduction of potential risk of failure, duration of outages; avoidance of emergency repairs that will require a greater duration which in turn impacts the customer's day-to-day life.
Reliability	Removing legacy infrastructure and installing standardized materials and utilizing current design standards will assist with maintaining reliability levels.
Safety	Removing legacy infrastructure, including restricted conductors and installing standardized materials; utilizing current design standards will improve safety for WHESC staff. Relocating primary assets to the accessible road allowance will increase the safety for both the general public and WHESC staff.

2. Investment Need

Primary Driver:

Failure Risk –The focus of this project is to replace aged rear-lot assets and restricted conductors due to the high cost, risk, and outcome associated with failure.

Secondary Driver:

Reliability – The project will replace legacy infrastructure that is not constructed to current standards and is operating beyond its TUL

Information Used to Justify the Investment:

WHESC's asset management process (Section 5.3 of the DSP), in conjunction with our ACA and project prioritization determined the scheduling of this investment. The planned replacements in this project ensure that WHESC continues to mitigate risk and maintains a safe electrical distribution system.

3. Investment Justification

Demonstrated Utility Practice:

All new installations comply with the latest safety standards and regulations.

Standards and construction are completed as per the requirements of CSA 22.3 No.1 Overhead Systems and CSA 22.3 No.7 Underground Systems.

WHESC is a member of the Utilities Standards Form (USF) and uses the USF standards, in conjunction with WHESC internally developed standards. The use of USF standards harmonizes design and construction of WHESC projects with all other USF members.

Design and construction are completed to be compliant with the requirements of Ontario Regulation 22/04 (Reg 22/04). During the historical period WHESC has achieved compliance with Reg 22/04. This planned program will ensure WHESC can continue to be compliant over the course of the forecast period.

Cost-Benefit Analysis:

All projects are reviewed to determine the most cost-effective method of completion, while ensuring design and construction are completed to the latest standards, specifications, and system requirements to provide system flexibility under normal and emergency operating conditions. WHESC reviewed alternative options within Section 7, Part A of this document and found no other practical, cost-effective alternative that provides the same level of benefit to customers. The assets are approaching end of life and replacement will be required. Planned programs are more efficient than reactive replacements.

Historical Outcomes

Rear-lot conversion is a new program WHESC, there are no directly comparable historical costs for work of this nature completed in a program other than indirect references to historical overhead and underground rebuilds.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This project consists of capital expenditures related to the replacement assets that are approaching end of life and that have deteriorated. These assets are located along Thorold Rd from Rose Ave to Clare Ave. Construction will include the installation of new wood poles, insulators, conductors, transformers, switches and associated hardware. The installation will provide increased pole height to maintain an existing 4.16kV intertie, while introducing an additional 27.6kV circuit.

The extension of an existing 27.6kV circuit will provide greater capacity to the project area. Existing loads located within the project area will be converted from 4.16kV to 27.6kV. This will lessen the capacity requirements of the existing 4.16kV system, reduce the reliance on existing substation assets, and lower system losses. Maintaining the existing 4.16kV circuit ensures that feeder ties between the 9F2 (MS9) feeder and 10F2 (MS10) feeder remain, allowing for greater flexibility within the system in normal and emergency operating conditions.

Completion of the Thorold Rd – Clare Ave to Rose Ave – Rebuild/Conversion project will provide provisions for a subsequent future extension along Clare Ave to Fitch St, which will support future underground rebuild / voltage conversion projects in the general area.

Project Area

(Project area is shown in orange.)

Major Assets Impacted:

Assets identified below are shown by asset quantity. The quantity of assets has been identified as those requiring replacement or refurbishment as part of this project and was determined by the project type and project scope. These assets directly or indirectly impact the total expenditure required by this project.

Poles		
Location	**Quantity**	**Average Age**
Rear Lot Poles	0	0
Street Front Poles	28	46

Transformers			
Type	**Quantity**	**Total KVA**	**Average Age**
1-Phase	4	225	51
3-Phase	4	450	42

Conductor		
Type	**Quantity (m)**	**Average Age**
1-Phase Overhead	4.8	64
3-Phase Overhead	964.8	56
1-Phase Underground	31.1	35
3-Phase Underground	48.3	22

Restricted Conductor (m)	0

2. Timing

a) Beginning: Beginning April 2025

b) In-Service: December 2025

c) Key factors that may affect timing: Project execution may be impacted by the procurement delays associated with labour and materials. Additionally, execution may be impacted by unplanned and/or higher priority work arising that may cause resource constraints.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	-	-	-	-	992	811	556	800	500	1,025	945	1,392	600
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	-	-	-	-	992	811	556	800	500	1,025	945	1,392	600

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs for equivalent projects. WHESC forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation.

6. Investment Priority

Using the prioritization process outlined in section 5.3 of the DSP, the project included has a priority ranking of 7 out of 40. In order to maintain system integrity and reliable service to customers, WHESC plans to replace the noted infrastructure. If not replaced these assets will continue to deteriorate which may lead to an increase in outage frequency and duration.

7. Alternative Analysis

c) **Do nothing/run to fail approach:** The do nothing / run to fail approach is not a viable option. The existing infrastructure has reached its end of life, and the risk and consequence of failure is high. The costs of emergency replacement greatly exceed the costs of planned replacement.

d) **Remove existing 4.16KV circuitry:** Removal of the existing 4.16KV circuity will sever a feeder tie between the 9F2 (MS9) feeder and 10F2 (MS10) feeder, which in turn will restrict system operation in normal and emergency conditions.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements.

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	The proactive replacement of the noted infrastructure which has reached end of life will greatly decrease the probably of failure in this distribution area
Customer Value	Customers will receive value from future lower line losses due to the higher operating voltage as well as the increased capacity to service new or increased existing loads via the 27.6KV infrastructure. The renewal of this infrastructure will have the following benefits: reduction of potential risk of failure and duration of outage; avoidance of emergency repairs that will require a greater duration which in turn impacts the customer's day-to-day life.
Reliability	Removing legacy infrastructure and installing standardized materials; utilizing current design standards will assist with maintaining reliability levels.
Safety	Removing legacy infrastructure and installing standardized materials; utilizing current design standards will improve safety for WHESC staff.

2. Investment Need

Primary Driver:

Failure Risk –The focus of this project is to replace aged assets due to the high cost and risk / consequence of a potential failure.

Secondary Driver:

Reliability – The project will replace legacy infrastructure that is not constructed to current standards and is operating beyond its TUL

Information Used to Justify the Investment:

WHESC's asset management process (Section 5.3 of the DSP), in conjunction with our ACA and project prioritization determined the scheduling of this investment. The planned replacements in this project ensure that WHESC continues to mitigate risk and maintains a safe electrical distribution system.

3. Investment Justification

Demonstrated Utility Practice:

All new installations comply with the latest safety standards and regulations.

Standards and construction are completed as per the requirements of CSA 22.3 No.1 Overhead Systems and CSA 22.3 No.7 Underground Systems.

WHESC is a member of the Utilities Standards Form (USF) and uses the USF standards, in conjunction with WHESC internally developed standards. The use of USF standards harmonizes design and construction of WHESC projects with all other USF members.

Design and construction are completed to be compliant with the requirements of Ontario Regulation 22/04 (Reg 22/04). During the historical period WHESC has achieved compliance with Reg 22/04 and this planned program will ensure WHESC can continue to be compliant over the course of the forecast period.

Cost-Benefit Analysis:

All projects are reviewed to determine the most cost-effective method of completion, while ensuring design and construction are completed to the latest standards, specifications, and system requirements to provide system flexibility under normal and emergency operating conditions. WHESC reviewed alternative options within Section 7, Part A of this document and found no other practical, cost-effective alternative that provides the same level of benefits to customers.

The alternative to proactive planned replacements is un-planned reactive replacements, which typically exceed planned program costs.

Historical Outcomes

The historical costs of equivalent projects completed during the historical period are detailed within Sections 3 and 5 in Part A of this document.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This project consists of capital expenditures related to the renewal of aging live-front switchgear units with current standard dead-front switchgear. WHESC continues to complete visual inspections, incorporating infrared scanning of all switchgear units within the system as per our inspection requirements outlined within the DSC and Regulation 22/04. Throughout this process WHESC has identified several live-front switchgears that experienced internal heating due to contamination. CO_2 cleaning was utilized for several years to mitigate contamination issues. This approach was found to be inadequate as pre-mature unit failure continued to occur between cleaning cycles.

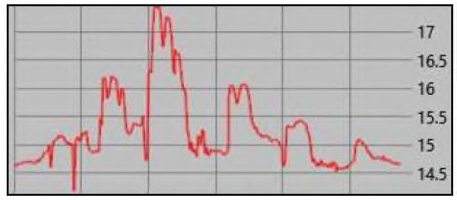
Over the course of the historic period, WHESC experienced two live-front switchgear failures which required emergency replacement. Through WHESC's asset management planning processes it was determined that the most cost-effective long term approach is to replace all existing live-front units with dead-front style units. This approach also provides the maximum reliability benefit.

Live-front switchgear incorporates exposed energized components by design. Dead-front switchgear is designed to have no exposed energized components. Additionally, live-front switchgear units consist of an open air insulated design, which are prone to contamination. WHESC's distribution system contains 23 live-front switchgear units installed within the 27.6kV system. The switchgear units are predominantly installed in locations serving commercial customers.

Units targeted for replacement are identified through review of field inspections and risk assessments. Typically, there is a main feed to each switchgear which is either radial or looped supplied. From the switchgear there are either a single or double fuse protected feeds that supply commercial or residential loads. The loads supplied from the switchgear can be either radially or loop fed. If the supplied loads are loop fed, the switchgear can be taken out of service without the requirement for an outage to the supplied customers. If the supplied loads are radial fed, an outage will be required to take the switchgear out of service. The systematic interconnections of the switchgear are reviewed and considered in conjunction with the asset condition when determining replacement priority.

Example of Infrared Heating

Object Emissivity	1.00
Object Distance	0.0 m
Atmospheric Temperature	14.0 °C
Relative humidity	50%



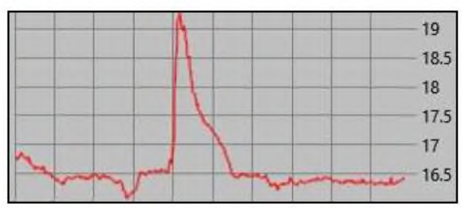
Location

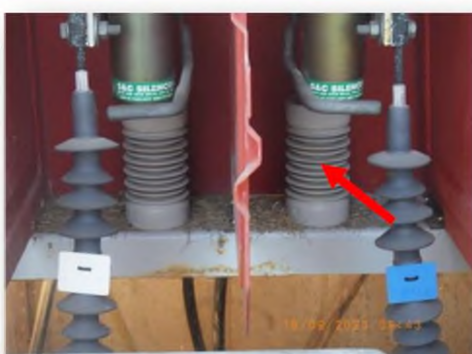
PMH Location #**SG7**
Compartment 1
At #300 Daimler Parkway,
Daimler Parkway at Old Course Trail,
WELLAND.

Description

Tracking/corona noted on white phase blade insulator.

Object Emissivity	1.00
Object Distance	1.0 m
Atmospheric Temperature	16.0 °C
Relative humidity	86%





Location

PMH Location #**SG4**
Compartment 3
Daimler Parkway at Magnolia Lane,
WELLAND.

Description

Tracking/corona noted on blue phase rear insulator.

2. Timing

a) **Beginning:** January 2025

b) **In-Service:** Through to December 2029

c) **Key factors that may affect timing:** Project execution may be impacted by the procurement delays associated with labour and materials. Additionally, execution may be impacted by unplanned and/or higher priority work arising that may cause resource constraints.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	-	-	-	-	-	33	-	250	257	265	273	281	289
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	-	-	-	-	-	33	-	250	257	265	273	281	289

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs related to the GL account. The planned program will commence in 2024 and proceed throughout the forecast period. Historical switchgear replacements have been like for like and did not incorporate introduction of the dead-front unit. WHESC forecasted costs are based on historical labour experience, known material costs, and increases applied to account for inflation.

6. Investment Priority

Using the prioritization process outlined in section 5.3 of the DSP, the projects included within this program have a priority ranking of 5 out of 40. To maintain system integrity and reliable service to customers, WHESC plans to replace the noted switchgear infrastructure. If not replaced these assets will continue to deteriorate which may lead to an increase in outage frequency and duration.

7. Alternative Analysis

e) **Do nothing/run to fail approach:** The do nothing/ run to fail approach is not a viable option. The result will be reactive replacement which has the potential to result in long outage durations, potentially outside of regular business hours, resulting in a higher cost of replacement.

f) **Replace assets with equivalent live-front switchgear:** Replacing assets with equivalent live-front switchgear is not a viable option. The risk of contamination and premature failure will remain, which in turn will result in increased emergency replacement costs. There are no significant cost savings in deploying the live front standard.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	This project has some effect on system efficiency as a failure to switchgear assets may result in untimely asset failure and system reliability concerns. This will have a negative impact on operating efficiency at a given time.
Customer Value	The renewal of this infrastructure will have the following benefits: reduction of potential risk of failure and duration of outage; avoidance of emergency repairs that will require a greater duration which in turn impacts the customer's day-to-day life.
Reliability	Removing legacy infrastructure and installing standardized materials; utilizing current design standards will assist with maintaining reliability levels.
Safety	Removing live-front infrastructure and installing dead-front infrastructure while incorporating current design standards will improve safety for WHESC staff.

2. Investment Need

Primary Driver:

Failure Risk – The focus of this project is to replace critical assets due to the high cost and risk / consequence of a potential failure. A failure of critical infrastructure can lead to an extended, expensive outage and restoration effort.

Secondary Driver:

Reliability – The risk to the utility and the customer is that the asset will fail and result in an outage that negatively affects reliability.

Information Used to Justify the Investment:

WHESC's asset management process (Section 5.3 of the DSP), in conjunction with our ACA and project prioritization determined the scheduling of this investment. The planned replacements in this project ensure that WHESC continues to mitigate risk and maintains a safe electrical system.

3. Investment Justification

Demonstrated Utility Practice:

All new installations comply with the latest safety standards and regulations.

Standards and construction are completed as per the requirements of CSA 22.3 No.1 Overhead Systems and CSA 22.3 No.7 Underground Systems.

WHESC is a member of the Utilities Standards Form (USF) and uses the USF standards, in conjunction with WHESC internally developed standards. The use of USF standards harmonizes design and construction of WHESC projects with all other USF members.

Design and construction are completed to be compliant with the requirements of Ontario Regulation 22/04 (Reg 22/04). During the historical period WHESC has achieved compliance with Reg 22/04. This planned program will ensure WHESC can continue to be compliant over the course of the forecast period.

Cost-Benefit Analysis:

All projects are reviewed to determine the most cost-effective method of completion, while ensuring design and construction are completed to the latest standards, specifications, and system requirements to provide system flexibility under normal and emergency operating conditions. WHESC reviewed alternative options within Section 7, Part A of this document and found no other practical, cost-effective alternative that provides the same level of benefit to customers.

Historical Outcomes

The historical costs of equivalent projects completed during the historical period are detailed within Sections 3 and 5 in Part A of this document. Again, it should be noted that historical replacements have been like for like.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This program consists of capital expenditures associated with miscellaneous renewals (i.e. individual asset replacements rather than rebuild projects) related to:

- Poles Replacements
- Transformer Replacements
- Reactive OH & UG System Replacements

Assets replaced under this program are either at the end of their useful life or have prematurely degraded beyond what would normally be expected for the specific asset class, and for which a renewal project is not justified. These assets are identified through WHESC annual field inspections, reported by internal staff or through customers inquiries.

The projects completed under this program range from the replacement of a single pole or transformer to the replacement of several assets with a total cost that falls under the materially threshold and therefore are not identified as an Overhead of Underground Renewal project.

2. Timing

a) Beginning: Beginning January 2025

b) In-Service: Through to December 2029

c) Key factors that may affect timing: Project execution may be impacted by the procurement delays in labour or materials. Additionally, execution may be impacted by unplanned and/or higher priority work arising that may cause resource constraints.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	329	721	644	486	852	805	606	355	666	686	706	728	749
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	329	721	644	486	852	805	606	355	666	686	706	728	749

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Section 3 of this document identifies WHESC's historical costs for equivalent projects. WHESC forecasted costs are based on historical equivalent projects with increases applied to materials and labour to account for inflation. As identified within section 5.2.2.1 of the DSP, WHESC's customers indicated support for the acceleration of System Renewal investments. The survey results, in conjunction with WHESC's overall financials, were taken into consideration when determining future capital expenditures.

WHESC initially forecasted the replacement of 20 miscellaneous poles per year that are in very poor condition. Upon completion of the customer survey, it was found that our customers were in favor of WHESC replacing an additional 200 poles in the forecast period that are in either very poor or poor condition, in order to keep pace with asset degradation. WHESC reviewed the survey results and ultimately decided that it was financially prudent to plan for the replacement of an additional 100 poles in the forecast period, by increasing individual pole replacements to 40 per year.

6. Investment Priority

Using the prioritization process outlined in section 5.3 of the DSP. The projects included within this program have a priority ranking of 8 and 9 out of 40. The assets replaced within this program maintain system integrity and reliable service to customers.

7. Alternative Analysis

a) **Do nothing/run to fail approach:** The do nothing/ run to fail approach is not a viable option. Reactive asset replacements have the potential to result in extended outage durations to affected customers and may occur out-side of normal business hours which will result in higher costs to complete.

b) **Replace overhead infrastructure with underground infrastructure:** The installation of underground infrastructure in place of overhead infrastructure would result in significant costs increases compared to maintaining the existing overhead infrastructure. For this reason, this alternative is not a viable option.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	The proactive replacement of the noted infrastructure that has reached end of life and/or prematurely degraded beyond what would normally be expected for the specific asset class will greatly decrease the probably of failure throughout WHESC's distribution service territory. Proactive replacements are more cost-effective than reactive replacements.
Customer Value	The renewal of this infrastructure will have the following benefits: reduction of potential risk of failure and duration of outage; avoidance of emergency repairs that will require a greater duration which in turn impacts the customer's day-to-day life.
Reliability	Removing degraded infrastructure, while installing standardized materials and utilizing current design standards will assist with maintaining reliability levels.
Safety	Removing degraded infrastructure, while installing standardized materials, utilizing current design standards will improve safety for WHESC staff.

2. Investment Need

Primary Driver:

Failure Risk –The focus of this project is to proactively replace degraded assets due to the high cost and risk / consequence of failure.

Secondary Driver:

Reliability – The project will replace legacy infrastructure that is not built to current standards, is beyond its TUL or has prematurely degraded beyond what would normally be expected for the specific asset class.

Information Used to Justify the Investment:

WHESC's asset management process (Section 5.3 of the DSP), in conjunction with our ACA and project prioritization determined the scheduling of this investment. The planned replacements in this project ensure that WHESC continues to mitigate risk and maintain a safe electrical distribution system. WHESC's ACA identified 591 poles in very poor and 2223 in poor condition, while approximately 44% are past TUL.

3. Investment Justification

Demonstrated Utility Practice:

All new installations comply with the latest safety standards and regulations.

Standards and construction are completed as per the requirements of CSA 22.3 No.1 Overhead Systems and CSA 22.3 No.7 Underground Systems.

WHESC is a member of the Utilities Standards Form (USF) and uses the USF standards, in conjunction with WHESC internally developed standards. The use of USF standards harmonizes design and construction of WHESC projects with all other USF members.

Design and construction are completed to be compliant with the requirements of Ontario Regulation 22/04 (Reg 22/04). During the historical period WHESC has achieved compliance with Reg 22/04 and this planned program will ensure that WHESC can continue to be compliant over the course of the forecast period.

Cost-Benefit Analysis:

All projects are reviewed to determine the most cost-effective method of completion, while ensuring design and construction are completed to the latest standards, specifications, and system requirements to provide system flexibility under normal and emergency operating conditions. WHESC reviewed alternative options within Section 7, Part A of this document and found no other practical, cost-effective alternative that provides the same level of benefit to customers.

Historical Outcomes

The historical costs of equivalent projects completed during the historical period are detailed within Sections 3 and 5 in Part A of this document.

4. Conservation and Demand Management

CDM is not applicable for this project.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This investment program pertains to the addition and deployment of new automated devices to replace in-service technology that is antiquated and near end of life, minimize outage duration and impacts via segmentation of grid expansions and provide operators the ability to fully leverage real-time technology to promptly address system disturbances that require management.

The investments facilitate the incorporation of:

- Real-time monitored / automated devices – remotely configurable to be switched based on system requirements to act as a (recloser / mid-sectionalizer / end-sectionalizer and fault indicating devices)
- Remote fault indicators

The primary objective of this program is to minimize maintenance costs and to mitigate interruptions associated with WHESC Infrastructure. WHESC intends to strategically deploy three automated devices each year during the period of 2025-2029 that can be configured as a recloser, mid-point sectionalizer, end-point sectionalizer, or fault indicating switch at key points across the distribution system, aiming to enhance the overall reliability and efficiency of the network, and minimize disruptions.

With the implementation of automated devices, WHESC is facilitating the capabilities of remote operation, accurate real-time outage detection as well as the ability to isolate itself from downstream events. Further, incremental data about WHESC's distribution system is gathered and fed into the SmartMAP platform. Many of these devices are critical in not only improving reliability and efficiency but also modernizing grid operation to facilitate the Distributed System Operator (DSO) model.

2. Timing

A. Beginning: 2025

B. In-Service: 2025 through to 2029.

C. Factors that may impact timing: Factors that may impact timing of the proposed investment include:

- Resource constraints
- Supply chain issues
- Third-part contractor availability
- Project prioritization
- Overall budget constraints

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	29	113	103	79	267	313	141	160	242	249	257	264	272
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	29	113	103	79	267	313	141	160	242	249	257	264	272

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

Historical costs have varied year over year in accordance with specific needs identified and works undertaken. Due to the nature of the projects within this program and the fact that works are completed on an as-needed basis depending on the need, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any trend.

6. Investment Priority

This program is considered to be of high priority. The investments in this program are aimed at replacing in-service technology that is antiquated and nearing end of life. Replacements are intended to reduce ongoing maintenance and communication costs associated with these devices. In addition, investments in this program support modernization and hardening of WHESC's grid to maintain levels of reliability as well as support future DSO model initiatives.

This program was ranked 8th based on Table 5.4-17 of WHESC's DSP.

7. Alternative Analysis

Do nothing: Doing nothing is not a viable option. The existing assets are aged technology with reduced functionally for fault detecting and locating. The proposed investments will modernize WHESC's grid infrastructure and improve safety, reliability, and efficiency.

Carry out the proposed pacing of investments: This is the preferred option as it allows WHESC to continue to support its operations. WHESC evaluates the identified needs to determine which is the most critical to undertake and which can be monitored and deferred to later years. Project-specific alternatives are considered on a case-by-case basis depending on the identified need.

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 and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	Modernization of grid infrastructure devices and technology will improve operational efficiency within WHESC's distribution system by replacing assets that are nearing end-of-life with newer technology, improving continuity of electricity supply to our customers. Technologies that are able to identify and locate faults quickly can significantly reduce response times and streamline restoration processes, optimizing energy flow and resource allocation.
Customer Value	Customers will benefit from grid modernization technologies. Proactive fault detection and rapid restoration capabilities will result in reduced service interruptions, providing customers with a more reliable and consistent energy supply. This advanced infrastructure aligns with evolving customer expectations, offering enhanced satisfaction and confidence in distribution system reliability.
Reliability	The modernized infrastructure will improve reliability. The proposed investment will improve the system's ability to address disturbances and disruptions. This will minimize outage duration, enhance overall network resilience, and contribute to a highly dependable and robust electrical distribution grid.
Safety	The implementation of modernized grid technology will enhance safety in power distribution. Swift detection and isolation of faults will minimize risks associated with electrical failures, ensuring a safer environment for both WHESC personnel and customers. The proactive nature of the system will contribute to early intervention and mitigation of potential hazards.

2. Investment Need

Primary Driver: Cost Effectiveness – The deployment of intelligent automated devices are able to sectionalize the outage area and assist crews to quickly locate the problem and restore power promoting operational efficiencies.

Secondary Driver: To improve service continuity and power quality by minimizing the duration and extent of outages through the enhancement of added monitoring and functionality to better meet the expectations of our customers.

Information used to Justify the Investment: WHESC, continuously monitors the condition and effectiveness of its systems using key metrics including:

- Reliability statistics – (SAIDI, SAFI, CAIDI, etc.).
- Improved asst utilization and increased operational efficiency

3. Investment Justification

Demonstrated Utility Practice: A utility's core function is the delivery of secure, dependable, and efficient services, and it is standard utility practice to incorporate modern technology that enables this function. Self-healing grid technology is the latest development in a long line of technological improvements that have been readily accepted by the industry.

Cost-Benefits: WHESC continually assesses the costs and benefits of undertaking new projects. This includes reviewing the benefits of implementation, the consequences of deferral, evaluating multiple quotes when working with other partners, and emphasizing both cost-effectiveness and timely delivery. The proposed investment to modernize grid infrastructure will mitigate the likelihood and impact of outages and disruptions, minimize maintenance costs through the replacement of existing devices and ancillary equipment that is nearing end of life.

Historical Outcomes: WHESC proactive approach in implementing smart grid technology – (Reclosers / Sectionalizers / Fault Detection) has enabled minimization of outage durations and more efficient management of the distribution system through remote operation.

Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management.

This is not applicable.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This capital program contains investments in information systems by WHESC to address IT and OT hardware and software needs. Modern and secure IT and OT infrastructure is critical to WHESC's operations and is required to distribute electricity to customers in a safe, reliable, and sustainable manner. Throughout the forecast period WHESC's planned investments are designed to sustain existing IT and OT system functionality while continuing to enable grid modernization investments.

Throughout the historical period, WHESC invested in IT infrastructure to mitigate ongoing operating expenses through what was primarily hosted infrastructure. WHESC brought critical systems on premise to improve cybersecurity posture and cost control. WHESC implemented a virtual server environment on premise while implementing some cloud-based solutions where a superior security posture was achieved.

For 2025, investment in replacement of WHESC's virtualized infrastructure is required due to the equipment reaching end of life. The currently deployed infrastructure will only be supported into the first quarter of 2025. Beyond 2025, planned investments are largely to sustain existing systems and are not expected to be over materiality.

The virtual server infrastructure supports corporate IT applications and is required to sustain functionality. The CIS and financial systems are key components installed on this infrastructure. There have been significant cost increases associated with the implementation and maintenance of virtual server software solutions, post COVID. This has caused WHESC to seek out alternative solutions to mange implementation and ongoing costs.

Investments under this program vary year to year based on the timing of required system replacements. For the forecast period, WHESC will incur $268,000 of capital investment summarized in the table below:

Project	2025 ($ '000)	2026 ($ '000)	2027 ($ '000)	2028 ($ '000)	2029 ($ '000)
Virtual Server Platform Replacement	94				
Operations Mobile Device Replacement	20				
Server Licensing Uplift	26	26	26		
SCADA Security Appliance Replacement		15			
Hardware Replacements			20	20	21
Gross Information Systems Expenditure	**140**	**41**	**46**	**20**	**21**

2. Timing

a) **Beginning:** 2025

b) **In-Service:** 2025 through to 2029.

c) **Factors that may impact timing:** Factors that may impact timing of the proposed investment include equipment procurement delays or changes in cybersecurity requirements.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	140	215	367	272	69	24	45	28	140	41	46	20	21
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	140	215	367	272	69	24	45	28	140	41	46	20	21

4. Economic Evaluation

Economic Evaluations are not applicable.

5. Comparative Historical Expenditure

During the historical period, WHESC invested in hardware and software licensing to move critical CIS, financial, and document management systems in house. This was to manage increases in ongoing operating expenses for hosted services and to mitigate cybersecurity framework compliance issues. Expenditures between 2017 and 2020 were related to configuration of a virtualized environment on premise and the staged migration of licensing from a hosted model. By the end of 2020, all three critical software systems were deployed on WHESC software. In 2022, WHESC solidified agreements with a third-party IT managed service provider which stabilized on-going operating costs associated with maintenance of WHESC's environment.

WHESC's forecasted capital costs associated with IT and OT systems reflect the trend of existing software vendors migrating to cloud-based solutions. While this does place additional pressure on associated OM&A expenditures, WHESC does not anticipate an impact on capital investment costs based on continuing deployment with existing vendors.

In the 2025 Test Year, most of the planned expenditure is related to replacement of the virtualized environment, based on vendor support terms. WHESC has performed alternative analysis to arrive at the lowest total cost of ownership for IT assets in the forecast period.

6. Investment Priority

This program has a high investment priority score at 11 of 40, based on the critical nature of IT/OT systems in relation to WHESC's business continuity. As highlighted above, the majority of test year investment is aimed at replacement of the virtualized infrastructure which has reached the end of vendor support terms. WHESC has already extended support two years beyond the initial term and has exhausted the possibility of further extension.

7. Alternative Analysis

Do nothing: Doing nothing is not an option based on the requirement of information systems deployed on the infrastructure identified for replacement. Business continuity depends on a stable IT and OT infrastructure.

Replace existing systems like-for-like: WHESC evaluated a like-for-like replacement of existing infrastructure and remaining with the existing hardware vendor. The estimated upfront cost of deployment was approximately $50,000 more than the chosen alternative. The ongoing operating costs for the life of the deployment was approximately $25,000 more annually due to annual subscription costs.

Replace existing systems based on current needs: The chosen alternative was to abandon the existing vendor and deploy a SAN-based virtualized environment at a captial cost savings of approximately $50,000, and an annual operating cost savings of $25,000. The selected technology matches WHESC'S current requirements for the virtualized environment.

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 and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	The migration of WHESC's virtualized environment to a SAN based platform results in lower annual operating costs than would have been experienced with a like-for-like replacement. In the forecast period, both capital requirements and OM&A benefit from cost control.
Customer Value	Customer's benefit from the lower overall total cost of ownership in the forecast period. WHESC's continues to improve its cybersecurity posture through controlling MSP costs.
Regulatory	Maintaining an IT/OT environment meeting current cybersecurity framework standards is crucial in protecting the integrity of WHESC's systems. With continued reliance on grid modernization deployments and the enhancement of customer facing technologies, WHESC must maintain a robust on-premise deployment for core systems.
Safety	WHESC's IT/OT systems are relied on by operational staff to perform real time operation of the distribution system and respond to disturbances. It is imperative that these systems have high-availability.

2. Investment Need

Primary Driver:

Failure Risk – Loss of Business Continuity: Existing assets are at end-of-life and beyond vendor support mechanisms. The primary driver for this program is to renew and invest in WHESC's IT/OT infrastructure due to asset retirement. Investments planned in this program are designed to permit WHESC to conduct 24 x 7 operations in an efficient and effective manner.

Secondary Driver:

Cyber Security: WHESC has made historical investments in this program to improve its cyber-security posture while managing ongoing cost impacts to customers. The requirement to manage the safety and integrity of sensitive data and systems against cyber threats is a secondary driver for this program.

Information Used to Justify the Investment:

WHESC continually monitors the health and status of its IT/OT systems through managed detection and MSP oversight. WHESC manages system replacement requirements based on asset registries that incorporate vendor support terms. Where possible, WHESC will extend the use of an IT/OT asset beyond TUL provided vendor support can be achieved. As WHESC's IT/OT systems are typically managed with third-party resources, WHESC acquires competitive request for quotation/proposal processes to make the most cost effective and technically sound asset replacement investment choices.

3. Investment Justification

Demonstrated Utility Practice: The proposed investments maintain WHESC's ability to deliver secure, reliable, and efficient services. LDCs depend on modern IT/OT infrastructure to meet the demands of today's essential functions. Cybersecurity requirements continue to evolve and therefore, hardware and software must be robust and current to protect the integrity of WHESC's day-to-day operations and safeguard customer's data.

Cost-Benefit Analysis: WHESC evaluates alternatives when undertaking IT or OT system projects. Cost effectiveness and adherence to requirements are fundamental to alternative analysis. WHESC has selected investments in the forecast period that manages the total cost of ownership for these systems.

Historical Outcomes: Historical investments have been completed to mitigate cybersecurity risk, and control ongoing operating costs related to IT/OT systems. WHESC current cost footprint is indicative of a stable IT/OT environment, designed to meet the anticipated needs of the forecast period.

Substantially Exceeding Materiality Threshold: The identified investments in the forecast period do not substantially exceed the materiality threshold.

4. Conservation and Demand Management.

This is not applicable.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

Welland Hydro-Electric System Corporation (WHESC) requires a diverse fleet of specialized vehicles to complete its daily activities. Heavy and light vehicles are essential for the quick restoration of power during outages, facilitates efficient construction and maintenance of the distribution system in addition to providing safety to our employees and the public.

To effectively manage fleet assets, WHESC has adopted the following objectives:

- Acquisition of safe, reliable and efficient vehicles and equipment to meet operational requirements
- Compliance with legislation and regulations
- Ability to provide interdepartmental flexibility to facilitate fleet size optimization
- Cost effectiveness and alignment with corporate funding objectives
- Environmental considerations

To achieve these objectives, WHESC maintains a multi-year capital plan to address short and long-term forecasting and includes the following criteria when establishing replacement of individual vehicles:

- Age, odometer read, PTO hours
- Maintenance Costs
- Annual & bi-annual vehicle inspection results
- Periodic 3rd party assessment condition reports
- Benefits of new technology
- Changing regulations
- Level of worker/public risk associated with failure

In addition to the standard metrics of evaluation – (vehicle age, mileage, engine / PTO hours, maintenance and inspection history, formal fleet asset condition assessments are leveraged when contemplating replacements. Table 1 below, summarizes vehicle replacements in the forecast period.

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	Health Index Score (%)	Condition
LV-1	2011 GMC Canyon	Pickup Truck	0%	45%	Poor
LV-3	2010 GMC Sierra	Pickup Truck	0%	40%	Poor
LV-53	2011 GMC Sierra P/U	Pickup Truck	0%	33%	Poor
HV-4	2010 Freightliner M2 106	Bucket Truck	0%	58%	Fair
HV-15	2009 International 4400	Bucket Truck	0%	55%	Fair
TR-33	1991 Nicholls Trailer	Trailer	0%	20%	Very Poor
TR-35	1982 Lge. Reel Trailer	Trailer	0%	20%	Very Poor

Table 1 – Fleet Condition Assessment – Replacements in the Forecast Period

WHESC's fleet assets are continually assessed for optimal replacement. This means vehicles could be retained longer due to better-than-average condition, while others may be replaced sooner due to poorer condition. Table 2 details the current fleet complement. Table 3 outlines the proposed replacements over the forecast period 2025-2029.

Category	2025	2029
Light Duty Vehicles	12	12
Heavy Duty – (Arial Devices)	6	5
Heavy Duty – (RBD)	2	2
Trailer – (Regular)	1	0
Trailer – (Dump)	3	3
Trailer – (Reel)	3	2
Trailer – (Pole)	1	1
Other	2	2
Total:	**30**	**27**

Table 2 – Fleet Summary

Category	Forecast Period				
	2025	2026	2027	2028	2029
Light Duty Vehicles	1	1	1	1	1
Heavy Duty – (Arial Devices)	-	-	1	-	-
Heavy Duty – (RBD)	-	-	-	-	-
Trailers	1	-	-	-	-
Other	-	-	-	1	-
Total:	**2**	**1**	**2**	**1**	**1**

Table 3 – Proposed Replacement Summary

2. Timing

a) Beginning: This is an annual investment initiative and will take place over the period of 2025 to 2029, with the start date being January 2025.

b) In-Service: 2025 through to 2029.

c) Factors that may impact timing: Factors that may impact timing include supply chain constraints, availability of equipment, and unexpected failures.

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	73	220	459	31	361	50	197	65*	529*	214	466	153	75
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	73	220	459	31	361	50	197	65	529	214	466	153	75

*See Section 5

4. Economic Evaluation

Economic Evaluation are not applicable.

5. Comparative Historical Expenditure

Section 3 above identifies our historical fleet costs. The quantity and scope of replacements year-to-year is based on asset condition assessment, inflation, supply chain and material cost factors for these assts. Factors that affect unit expenditures include:

- Chassis costs for heavy trucks have increased due to increased raw materials, labour, and freight
- Overall increase in pricing in light duty vehicles observed due to decrease in available inventory

- Equipment/body builders and upfit suppliers (Bucket/Radial Boom Derricks) to be mounted on heavy truck chassis have increased their pricing because of increased manufacturing costs related to raw materials, labour, and freight.
- COVID-19 pandemic had an adverse effect on many workforces. Many of WHESC's suppliers had difficulties securing resources during and post-COVID. This resulted in decreased production and increased costs throughout their manufacturing sites.
- The relatively large expense in 2025 is the result of a large fleet investment that was deferred from 2024 due to manufacturing lead time issues.

6. Investment Priority

Health and Safety: Having fleet vehicles in good condition is essential to the safety of WHESC personnel and the public. Vehicle and mobile assets are inevitably going to experience deterioration beyond repair. It is critical that WHESC replace these assets when they are no longer safe to continue operating.

Environmental Impact: WHESC continuously reviews the possibility of replacing its existing fleet (when nearing or at end-of-life) with alternative powered vehicles. While this would have a positive impact on environmental controls, it is not currently feasible to convert to an electric fleet. WHESC will continue to monitor its existing fleet and perform total lifecycle cost of ownership analysis to determine the most optimal time to convert to emission friendly vehicles.

Service Quality (Reliability): Mitigating fleet issues and vehicle failures will help WHESC continue to meet reliability standards and targets. Vehicles that are maintained and in good working condition will operate more consistently, ensure higher levels of safety, and enable crew members to work efficiently and help maintain service quality.

Financial Impact: The financial impact of avoiding fleet replacement would result in increased maintenance and operating cost. WHESC analyzes the financial impact of maintaining versus replacing its fleet to maximize cost efficiencies.

This investments in this program ranked 6th for the 55' bucket truck and 13th for the reel trailer based on Table 5.4-17 of WHESC's DSP.

7. Alternative Analysis

The alternatives for fleet replacements are the following:

1. **Do nothing**: (continue to utilize existing fleet and repair as needed) – as the vehicles age, the required maintenance and downtime will likely increase, resulting in increased operational costs. This is not a viable option as it deviates from WHESC's commitment to cost efficiency and service level.
2. **Replace with reduced specification vehicles**: This would result in a loss of functionality of the asset and work activities on energized powerline apparatus would be limited / restricted. This would also place an increase demand on the remaining fleet vehicles which would result in scheduling conflicts and result in a loss of effectiveness and productivity. This is not a viable option.
3. **Purchase Used** - This alternative was not considered for these investments in the forecast period, however this approach has been used in the past. The issues associated with a used purchase are that there is a considerable risk on the dependability of the vehicle. Additionally, WHESC places the TUL on large vehicles at 15 years which is above the average value used amongst LDCs in Ontario. Based on WHESC's experience with maintenance costs on used vehicles and the limited service life, there is no advantage of this approach based on total cost of ownership when compared to purchasing new.

8. Innovative Nature of the Project

During the forecast period, WHESC will evaluate hybrid / full electric options against traditional combustion engine vehicles for light duty replacements.

9. Leave to Construct Approval

Not applicable to this program.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	Consistent management of WHESC's fleet will ensure that life cycle costs and risk of catastrophic failure remain low. Planned replacement of the fleet ensures that WHESC staff are using safe, efficient and reliable equipment while on the job. Unreliable fleet can negatively impact safety, performance and reliability. As vehicles age, they incur higher operating expenses due to increased levels of reactive repairs.
Customer Value	The replacement of end-of-life fleet vehicles will allow WHESC to maintain its ability to provide a timely, safe and reliable service to our customers. A safe and reliable fleet reduces operating and maintenance costs to mitigate the risk of work disruption due to breakdowns.
Reliability	The replacement of end-of-life fleet vehicles allows for the continued efficient day to day operations of WHESC's business. Having reliable vehicles is essential in the delivery of reliable electricity as it mitigates downtime prolonged by vehicle / equipment breakdown.
Safety	Planned replacement of fleet mitigates any catastrophic failure which may threaten the safety of employees and the public.

2. Investment Need

Primary Driver: The main driver for this program is addressing the increased impact of cost associated with the maintenance, repairs and operational effectiveness as assets approach TUL.

Secondary Driver: Investments into fleet vehicle replacements when vehicles reach end-of-life is essential to ensure that WHESC continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities.

Information Used to Justify the Investment: WHESC's vehicle replacement strategy is to replace light vehicles after 10 years and large vehicles after 15 years of service. When replacing vehicles, WHESC considers safety, vehicle age, mileage, engine / PTO hours, annual maintenance, and inspection results. The forecasted costs for 2025 – 2029 are based on estimates from dealerships or manufacturers.

3. Investment Justification

Demonstrated Utility Practice: In order to safely and effectively service our distribution system, it is critical that WHESC's fleet vehicles are reliable. Reliability is crucial in enabling crews to respond to outages in a timely manner. In addition, a reliable fleet helps WHESC staff complete the required operation, maintenance, and capital construction projects and objectives. Regulations such as the Highway Traffic Act, set out rules and requirements for all commercial vehicles. WHESC must ensure its vehicles comply with this act through maintenance of existing vehicles and through this vehicle replacement program.

Cost-Benefit Analysis: Ongoing vehicle maintenance is needed to ensure that WHESC staff continue to have access to safe and reliable fleet vehicles, needed to support the business. When it comes to replacing an existing end-of-life fleet asset, alternatives are evaluated on a case-by-case basis. Multiple estimates are obtained from dealerships and total cost of ownership is considered.

Historical Outcomes: WHESC's historical investments for this program are described in Section 5. Historical investments in this program have resulted in the ability for WHESC staff to have access to safe and reliable vehicles to support their job functions. This ensures that WHESC can continue to service the day-to-day needs of our customers while delivering safe and reliable electricity.

4. Conservation and Demand Management.

This is not applicable.

5. Innovation

This is not applicable.

A. General Information on the Program / Project

1. Overview

This program includes general repairs, replacements, and upgrades to WHESC's Service Centre to facilitate a safe and modernized environment for staff and our customers. Deferring investments in this category will have a detrimental impact on WHESC's operations that could affect both the safety of staff, as well as have a direct impact on the reliability of the system and the ability to deliver cost effective service.

Investments under this program vary from year to year based on specific needs identified during the planning process. For the 2025-2029 period, anticipated costs are expected to total $499,000. To further optimize WHESC's facility investment plan, a Building Condition Assessment (BCA) was carried out in the first quarter of 2024. A review of this assessment resulted in WHESC identifying investment needs that are critical for the continued operation of the facility based on its current usage and occupancy. Observations were made on the general physical condition of the property, material systems and components, deficiencies, unusual features, or inadequacies. During the review, most of the building components were considered in "fair" condition. Table 1 summarizes the planned expenditures in the forecast period.

Building & Fixtures	($ '000)				
	2025	2026	2027	2028	2029
Engineering / Operations renovations / upgrades	125	145			
Garage floor refurbishment		49			
Gate / fence repairs / replacement					75
HVAC replacement & balancing			32	35	37

Table 1 - 2025-2029 Forecast Expenditures

WHESC has prioritized facility improvements, separating conditional issues critical to the day-to-day operations from those that can be deferred. The result is planned renovations in the operations area of the building along with specific replacement expenditures in the garage and on HVAC systems. The specific replacement requirements are listed in Table 2.

Component	Description	Year of Replacement				
		2025	2026	2027	2028	2029
Single Glazed – Steel framed Windows – (Facility South-East Side)	The exterior steel framed single- and double-glazed windows located at the Southeast stairs and metering department were observed to be in very poor condition. Recommend replacement in the short term.	✓				
Vinyl Composite Tile – (VCT)	Vinyl composite tiles (VCT) are provided in the hallways, stairs area, old fire department office and, Engineering and metering department and are suspected of containing asbestos. The tiles were noted to be original and damaged. Recommend replacement in the short term.	✓				

HVAC – RTU	The 'Carrier' rooftop units were observed to be in very poor condition. The units are using R22 refrigerant. This refrigerant is no longer used in industry. We recommend replacement in the short term.			✓	✓	✓
Typical T12 / T8 Lighting	The interior light fixtures of the building consist of T12, T8 and T5 light fixtures (x295) and are noted to be in very poor condition. Newer LED light fixtures are available in the market for energy efficiency purposes. We recommend upgrading to LED light fixtures in the short term.	✓				
Acoustic Ceiling Tiles	Acoustic ceiling tiles (ACT) were observed at the upper level of the building and are in poor condition. Stained tiles were noted in the hallway and offices. We recommend repairs in the near future and replacement at a later stage.	✓				

Table 2 – 2025-2029 Priority Investments

2. Timing

a) Beginning: 2025

b) In-Service: 2025 through to 2029.

c) Factors that may impact timing: Factors that may impact timing of the proposed investment include:

- Resource constraints
- Supply chain issues
- Third-part contractor availability
- Project prioritization
- Overall budget constraints

3. Historical and Future Capital Expenditures

Category	Historical Period							Bridge	Forecast Period				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000	$ '000
Gross Capital Expenditure	132	108	346	9	5	-	36	390*	125	194	33	35	113
Capital Contributions	-	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenditure	132	108	346	9	5	-	36	390	125	194	33	35	113

*See section 5

4. Economic Evaluation

Economic evaluations are not applicable.

5. Comparative Historical Expenditure

Historical costs have varied year over year in accordance with specific needs identified and works undertaken. Due to the nature of the projects within this program and the fact that works are completed on an as-needed basis depending on the need, there are cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

The relatively large expenditure in 2024 was required to complete paving and renovations required based on inspection and condition assessment.

6. Investment Priority

This investment is required to sustain the effectiveness of WHESC's operations. A lack of investment in buildings and fixtures will increase reactive maintenance requirements, placing upward pressure on OM&A. Furthermore, sustainment of asset health is required to maintain the continuity of operations and provide a safe and effective environment for WHESC employees.

This program was ranked 12th based on Table 5.4-17 of WHESC's DSP.

7. Alternative Analysis

Do nothing: Doing nothing is not a viable option. Without investing in the ongoing repair, replacement, and upgrades of WHESC's building and yard facilities, there is a risk that these facilities will not be fit for staff to carry out their jobs safely and efficiently. Additionally, more cost will be incurred due to increased maintenance of existing building components in comparison to replacing components with sufficient upgrades.

Carry out the proposed pacing of investments: This is the preferred option as it allows WHESC to continue to support its operations. WHESC evaluates the identified needs to determine which are most critical to undertake and which can be monitored and deferred to subsequent years. Project-specific alternatives (e.g., run to fail vs. repair vs. replace like-for-like vs. upgrade with additional functionality) are considered on a case- by-case basis depending on the identified need.

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 and Safety

Primary Criteria for Evaluating Investment	Investment Alignment
Efficiency	Investments in buildings and fixtures ensure that WHESC's facilities remain modern, clean, safe, and secure. These investments will foster an environment for its staff that improves operational efficiency.
Customer Value	A modern, clean, and safe environment ensures that staff can undertake their work effectively and efficiently to address the needs of WHESC's customers.
Reliability	Through these investments, there is no direct impact on reliability of the network in terms of outages or system disturbances. However, these facilities are crucial to support continued WHESC operations. WHESC's service center house's equipment and materials that are used to sustain the reliability of the system.
Safety	Addressing damaged, obsolete, or end-of-life building assets through repair, replacement, and upgrades is crucial in averting failures that could jeopardize employee and public safety. This program allows WHESC to provide a secure workspace with functional building assets, in compliance with the latest health and safety standards.

2. Investment Need

Primary Driver: The primary driver for this program is to renew and invest in WHESC's service center that houses in-office and operational staff and equipment used for maintenance and operation activities.

Secondary Driver: WHESC's Service Centre is the central point of our operation. Providing protection of vehicles and equipment will ensure asset longevity and functionality when it is required.

Information Used to Justify the Investment: The majority of planned investment in this category is directed towards replacement of assets at or beyond TUL. Investment levels related to management of assets classified as general plant are determined based on requirements to sustain asset health. For fleet and facilities, formal asset assessments were conducted to better inform investment level requirements.

3. Investment Justification

Demonstrated Utility Practice: The proposed level of the investment is to ensure that WHESC can continue service delivery in a safe and reliable manner. It is common practice in the LDC space to maintain office facilities for staff to perform the in-office functions of administration, engineering, operations, finance, and customer service. Additionally, field staff must be supported with the appropriate tools, equipment, vehicles, and resources to effectively perform operations, maintenance and capital investment activities. It is good practice for utilities to allocate funds for maintaining operational buildings, yards, and storage areas. WHESC, having assessed sustainment requirements, has strategically planned its projects to protect its operations and maintain the delivery of safe, reliable, and efficient services.

Cost-Benefit: WHESC evaluates several estimates to ensure alignment to required asset specifications and management of cost with an effort to reasonably pace investments while sustaining asset health.

Historical Outcomes: Historical investments in buildings and fixtures have supported WHESC's operation and have enabled office staff and field crews to carry-out activities in a safe, efficient and cost effective manner. Historical investments have included roof membrane replacement, paving, and replacement of truck bay and garage systems. Investment in the roof system in the historical period is an example of an investment designed to upgrade the asset, rather than perform outright replacement. This was the most appropriate investment alternative in order to manage upfront costs along with ongoing operating costs to maintain the roof system.

4. Conservation and Demand Management.

This is not applicable.

5. Innovation

This is not applicable.

Appendix 5-B: Integrated Regional Resource Plan

Niagara Integrated Regional Resource Plan

December 22, 2022

Connecting Today.
Powering Tomorrow.

Disclaimer

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Acronym	Definition
CDM	Conservation and Demand Management
CNPI	Canadian Niagara Power Inc.
DG	Distributed Generation
DR	Demand Response
DS	Distribution Station
FIT	Feed-in-Tariff
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MTS	Municipal Transformer Station
MVA	Megavolt ampere
MW	Megawatt
NERC	North American Electric Reliability Corporation
NOTL	Niagara-on-the-Lake
NPCC	Northeast Power Coordinating Council

Acronym	Definition
NPEI	Niagara Peninsula Energy Inc.
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
TS	Transformer Station

1. Introduction

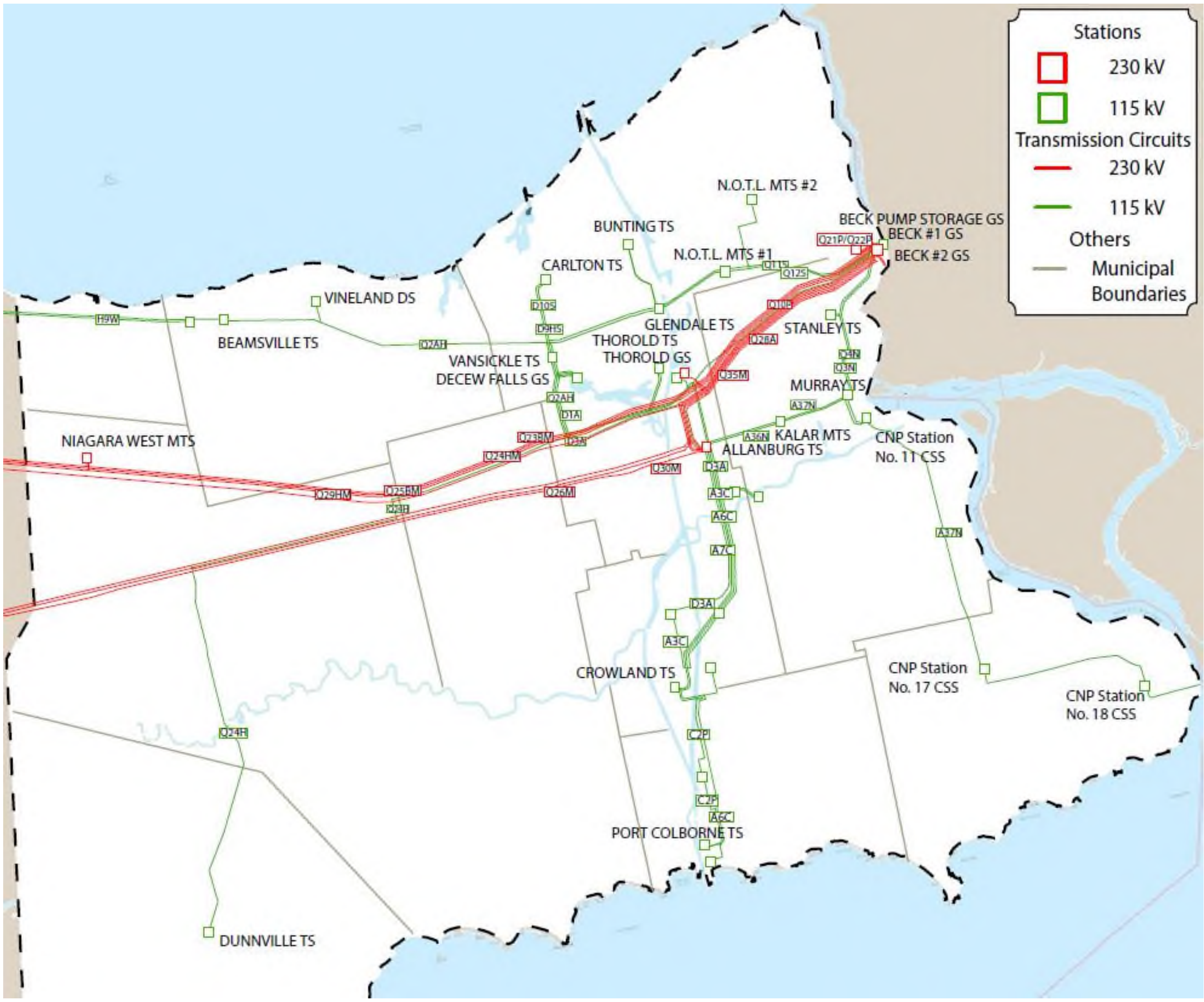
This Integrated Regional Resource Plan ("IRRP") addresses the electricity needs of the Niagara Region over the next 20 years, from 2022 to 2041. The Niagara Region is located between Lake Ontario and Lake Erie, and includes one upper-tier municipality (Regional Municipality of Niagara) and 12 lower-tier municipalities: Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln.

This region also includes the following First Nations and Métis Nation of Ontario councils:

- Mississaugas of the New Credit
- Oneida Nation of the Thames
- Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council)
- Métis Nation of Ontario Niagara Region Métis Council

The Niagara Region is summer-peaking and, over the last five years, peak electrical demand has remained steady at an average of 810 MW. Electrical supply is provided primarily through 230/115 kilovolt ("kV") autotransformers at Allanburg Transformer Station ("TS"), and is generally served by 230 kV and 115 kV transmission lines and step-down transformation facilities as shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits that connect Sir Adam Beck Generating Station ("GS") #2 in the east to Burlington TS and Middleport in the west. Other large transmission-connected generating facilities include Sir Adam Beck GS #1 and Decew Falls GS connecting to the 115 kV system, and Thorold GS connecting to the 230 kV system.

Figure 1 | Overview of the Niagara Region



The region's electricity is delivered by six local distribution companies ("LDCs"): Alectra Utilities, Canadian Niagara Power Inc. ("CNPI"), Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara on the Lake Hydro Inc., Niagara Peninsula Energy Inc. ("NPEI"), and Welland Hydro Electric System Corp. Hydro One Networks Inc. (Transmission) is the primary transmission asset owner. This IRRP report was prepared by the Independent Electricity System Operator ("IESO") on behalf of a Technical Working Group, composed of the LDCs, Hydro One, and the IESO.

Development of the Niagara IRRP was initiated in August 2021, following the publications of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment identified needs for further assessment through an IRRP. The Technical Working Group was then formed to gather data, identify near- to long-term needs in the region, and develop the recommended actions included in this IRRP.

This report is organized as follows:

- A summary of the recommended plan for the region is provided in Section 2;

- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the region and the study scope are discussed in Section 4;
- Demand forecast scenarios, and conservation and demand management and distributed generation assumptions, are described in Section 5;
- Electricity needs in the region are presented in Section 6;
- Alternatives and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement activities is provided in Section 8; and
- The conclusion is provided in Section 9.

2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the Niagara Region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system, as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria ("ORTAC") and reliability standards governed by the North American Electric Reliability Corporation ("NERC"). The IRRP's recommendations are informed by an evaluation of different options to meet the needs and consider: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

The Niagara electricity demand forecast, provided by the LDCs, projects sustained growth driven by community area, employment area, and rural settlement expansions. This growth spans multiple municipalities, including (but is not limited to): Lincoln, West Lincoln, Welland, Thorold, and Niagara Falls.

The IRRP recommendations below are organized under a near-/medium-term plan and other ongoing or long-term initiatives. This distinction reflects the different levels of forecast certainty, lead time for development, and planning commitment required over these time horizons. This approach ensures that the IRRP provides clear direction on investments needed in the near and medium term, while retaining flexibility over the long term, as electrification, energy efficiency, and development plans evolve.

2.1 Near-/Mid-Term Plan

The near- and mid-term plan comprises several recommendations to accommodate load growth, maintain reliability, and optimize asset replacement. Where possible, needs are grouped to align with integrated sets of solutions. These recommendations are summarized in Table 1 and further discussed below.

Table 1 | Summary of the Near/Mid-Term Plan for the Niagara IRRP

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West Municipal Transformer Station ("MTS"), and Vineland Distribution System ("DS") station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development of a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental conservation and demand management ("CDM") to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Monitor load growth and transfer load in excess of the station limit to Murray TS transformer 13 and 14 (T13/T14)	• 2023

2.1.1 Load Transfers from Beamsville TS and a New or Expanded 230 kV Station

Stations limits are typically dictated by the lowest rated transformer. Beamsville TS is fully utilized today and there is no remaining capacity for growth. Nearby stations Niagara West MTS and Vineland DS are also forecast to reach their capacity limits by 2026 and 2030, respectively.

The IRRP considered the merits of a portfolio of "non-wires" (non-transmission) options as well as integrated "wires" (transmission) options. Based on planning-level cost estimates and its ability to address capacity shortfalls at the three stations, the Technical Working Group recommends that a new 230 kV station supplied by Q23BM and Q25BM is built. This could be accomplished by expanding the existing Niagara West MTS. Development and implementation for additional capacity should begin as soon as possible for a targeted in-service date of 2026-2027. The next stage of regional planning, the Regional Infrastructure Plan ("RIP") led by Hydro One, should confirm the party who will lead development work (i.e., Grimsby Power, NPEI, or Hydro One).

In the meantime, the IRRP recommends that the local distributors (Grimsby Power, NPEI, Hydro One Distribution), in conjunction with Hydro One Transmission where appropriate, develop a plan to transfer load from Beamsville TS to the other nearby stations (Niagara West MTS, Vineland DS) to manage the urgent Beamsville TS need until the new station is in-service.

2.1.2 Major High Voltage Equipment Replacement of Crowland TS, New 230 kV Transmission Lines, Q28A Upgrade, and Control Actions

The existing T5 and T6 transformers at Crowland TS will require major high voltage ("HV") equipment replacement in 2026, and are forecast to be fully utilized in 2022. Crowland TS, as well as other stations supplied by the A6C/A7C circuits, are also impacted by a load security need that exists today. Moreover, Crowland TS is included in the broader Niagara 115 kV sub-system whose supply capacity need exists today and continues to grow by the end of the planning horizon.

The IRRP developed and evaluated portfolios of non-wires options, standalone generation, and wires alternatives for the multiple needs in this area. Ultimately, the most feasible and cost-effective solution at this time requires wires reinforcements: the upgrade of Q28A, the replacement of 115 kV Crowland TS with a larger 230 kV station supplied by new 230 kV transmission lines from Q24HM and Q29HM, and a new load rejection scheme developed to manage the Niagara 115 kV sub-system load. The IRRP recommends that Hydro One should begin implementation as soon as possible for a targeted in-service dates of 2024, 2024, and 2028 for the load rejection scheme, Q28A upgrade, and new 230 kV station and lines, respectively. Measures to manage the HV equipment replacement infrastructure at Crowland TS should be implemented by Hydro One until the station replacement is in-service.

2.1.3 Load Transfers from Murray TS (T11/T12)

Murray TS (T11/T12) is forecast to be beyond capacity in 2022 during its station peak. Given the small magnitude of this need and the available capacity on the other set of transformers at Murray TS (T13/T14), the IRRP recommends that some load is re-allocated to T13/T14 and growth continues to be monitored.

2.2 Ongoing Initiatives

In addition to the near- and mid-term plan above, two ongoing actions were identified to manage needs expected in the long-term.

2.2.1 Monitor Load Growth

Carlton TS and Kalar MTS are expected to reach capacity in 2028 and 2030, respectively. In the case of Carlton TS, distribution-level load transfers to Bunting TS have been indicated as an option. Given the timing, no firm recommendation is required at this time for either need; the Technical Working Group will continue to monitor load growth and revisit these needs in the next cycle of regional planning. As part of broader monitoring, the Technical Working Group should also keep apprised of and participate in any future Community Energy Plans developed by municipalities of the Niagara Region.

2.2.2 Explore Opportunities for Targeted CDM

In addition to monitoring how the forecast demand materializes, the IRRP recommends continuing to consider opportunities for targeted CDM. During the options analyses, the benefits and potential of incremental, cost-effective CDM were identified – particularly if targeted to manage near-term needs until transmission reinforcements are in-service (as is the case for the Beamsville TS/Vineland DS/Niagara West MTS area, as well as the 115 kV sub-system), or to defer long-term needs (such as at Kalar MTS). The Technical Working Group should continue to support and monitor CDM uptake, and bring these insights into the next cycle of regional planning for the Niagara Region.

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region – defined by common electricity supply infrastructure – over the near, medium, and long-term, and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecasts growth and customer reliability, evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the Ontario Energy Board in 2013 and is performed on a five-year cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitters and LDCs in each region. The process consists of four main components:

1. A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
2. A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
3. An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
4. A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional planning is not the only type of electricity planning in Ontario. Other types include bulk system planning and distribution system planning. There are inherent overlaps in all three levels of electricity infrastructure planning. Further details on the regional planning process and the IESO's approach to it can be found in Appendix A.

The IESO has recently completed a review of the regional planning process, following the completion of the first cycle of regional planning for all 21 regions. Additional information on the Regional Planning Process Review, along with the final report is posted on the IESO's website.

3.2 Niagara and IRRP Development

The process to develop the Niagara IRRP initiated in August 2021, following the publication of the Needs Assessment report in May 2021 by Hydro One and the Scoping Assessment Outcome Report in August 2021 by the IESO. The Scoping Assessment recommended that the needs identified for the Niagara Region be considered through an IRRP in a coordinated regional approach, supported with public engagement. The Technical Working Group was then formed to develop the terms of reference for this IRRP, gather data, identify needs, develop options, and recommend solutions for the region.

4. Background and Study Scope

This is the second cycle of regional planning for the Niagara Region. This region roughly encompasses the municipalities Fort Erie, Grimsby, Lincoln, Niagara Falls, Niagara-on-the-Lake, Pelham, Port Colborne, St. Catharines, Thorold, Wainfleet, Welland, and West Lincoln. This region also includes the following First Nations and Métis Nation of Ontario Councils: Mississaugas of the New Credit, Oneida Nation of the Thames, Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council), and the Métis Nation of Ontario Niagara Region Métis Council. Following a Needs Assessment and Scoping Assessment in 2016, a RIP was initiated by Hydro One and subsequently published in 2017, concluding the first planning cycle for the Niagara Region. An IRRP was not developed, as two electricity needs were identified in 2016, but no further regional coordination was required.

The current cycle of regional planning began in 2021 with the publication of the Needs Assessment Report, where several needs requiring further regional coordination were identified. The 2021 Niagara Scoping Assessment recommended an IRRP for the entire region to address needs in a coordinated manner. This report presents an integrated regional electricity plan for the next 20-year period starting from 2022.

This IRRP develops and recommends options to meet the electricity needs of the Niagara Region in the near, medium, and long term. The plan was prepared by the IESO on behalf of the Technical Working Group, and includes consideration of forecast electricity demand growth, CDM, distributed generation ("DG"), transmission and distribution system capability, relevant community plans, condition of transmission assets, and developments on the bulk transmission system.

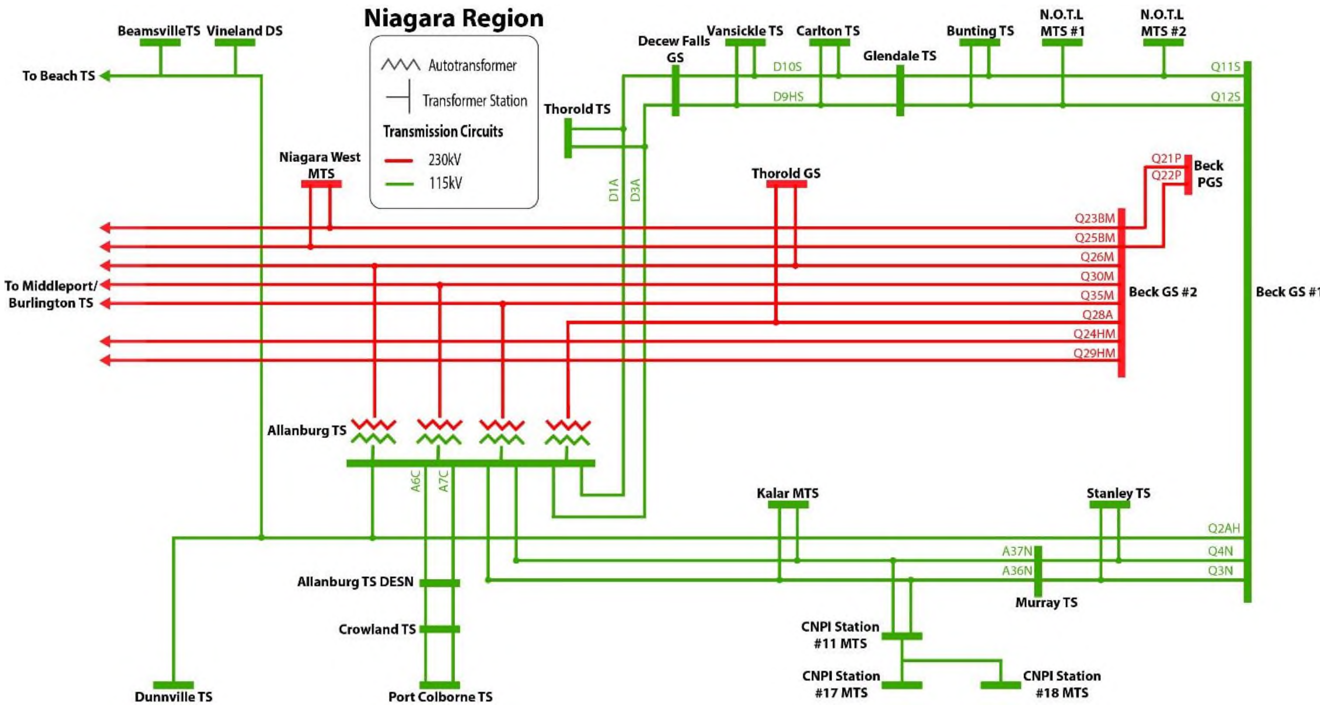
The following transmission facilities were included in the scope of this study:

- Transformer stations: Allanburg TS, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Murray TS, Niagara West MTS, Niagara-on-the-Lake ("NOTL") York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI #11 MTS, CNPI #17 MTS, CNPI #18 MTS. Except for Niagara West MTS, all stations are supplied from 115 kV transmission circuits.
- 115 kV transmission circuits: Q3N/Q4N, Q11S/Q12S, Q2AH, A36N/A37N, A6C/A7C, D1A/D3A, D9HS/D10S.
- 230 kV transmission circuits: Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M.

The single line diagram of the Niagara Region is shown in Figure 2 below. Note that the bulk system transfer capabilities on the Queenston Flow West interface[1] through the region is not within the scope of the IRRP and would be separately studied in a bulk transmission plan, as required. The schedule of bulk planning activities is identified through the IESO's Annual Planning Outlook.

[1]Includes flow out at Beck (Q25BM + Q23BM + Q24HM + Q29HM) and flow in at Middleport (Q30M + Q26M + Q35M).

Figure 2 | Single Line Diagram of the Niagara Region



The Niagara IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe (as described in the following steps);
    - Examining the load meeting capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying ORTAC and NERC criteria;
    - Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid;
    - Confirming identified asset replacement needs and timing with the transmitter and LDCs;
- Establishing alternatives to address system needs including, where feasible and applicable, generation, transmission and/or distribution, and other approaches such as non-wires alternatives including CDM;
- Engaging with the community on needs and possible alternatives;
- Evaluating alternatives to address near- and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

5. Electricity Demand Forecast

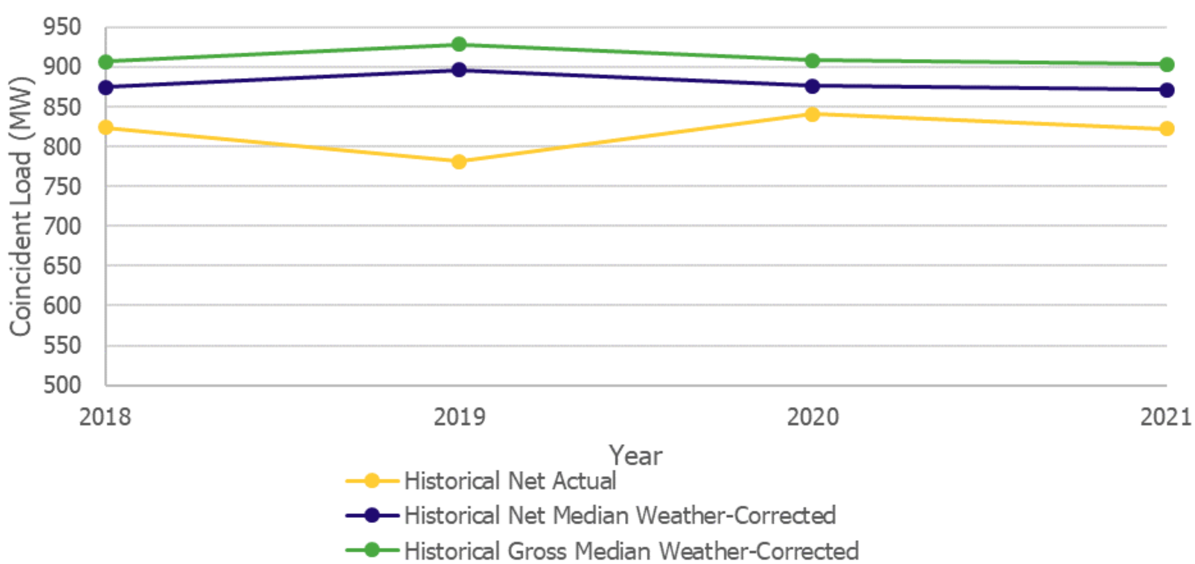
Regional planning in Ontario is driven by having to meet peak electricity demand requirements in the region. This section describes the development of the demand forecast for the Niagara Region. It highlights the assumptions made for peak demand forecasts, including weather correction, the contribution of CDM and DG, and the development of a high growth scenario. The reference net extreme weather demand forecast is used in assessing the electricity needs of the area over the planning horizon; the high forecast scenario, used as the basis for a sensitivity analysis, is described further in Section 5.7.

To evaluate the reliability of the electricity system, the regional planning process is typically concerned with the coincident peak demand for a given area. This is the demand observed at each station for the hour of the year in which overall demand in the study area is at its maximum. This differs from a non-coincident peak, which refers to each station's individual peak, regardless of whether these peaks occur at different times. Within the Niagara Region, the peak loading hour for each year has historically occurred in the summer.

5.1 Historical Demand

Peak electricity demand within the Niagara Region has been steady over the last four years. Figure 3 below shows the coincident net actual (as observed at the metering point), net median weather-corrected (adjusted to reflect median weather conditions), and gross median weather-corrected (contribution of DG removed) historical demand. The gross median weather-corrected demand has averaged 910 megawatts ("MW") over the past four years, with the peak demand hour for each year occurring consistently in the summer between approximately 4 PM to 7 PM. The 2021 gross median weather-corrected peak at each station in the Niagara Region was used as the starting point for the forecast.

Figure 3 | Historical Demand in the Niagara Region

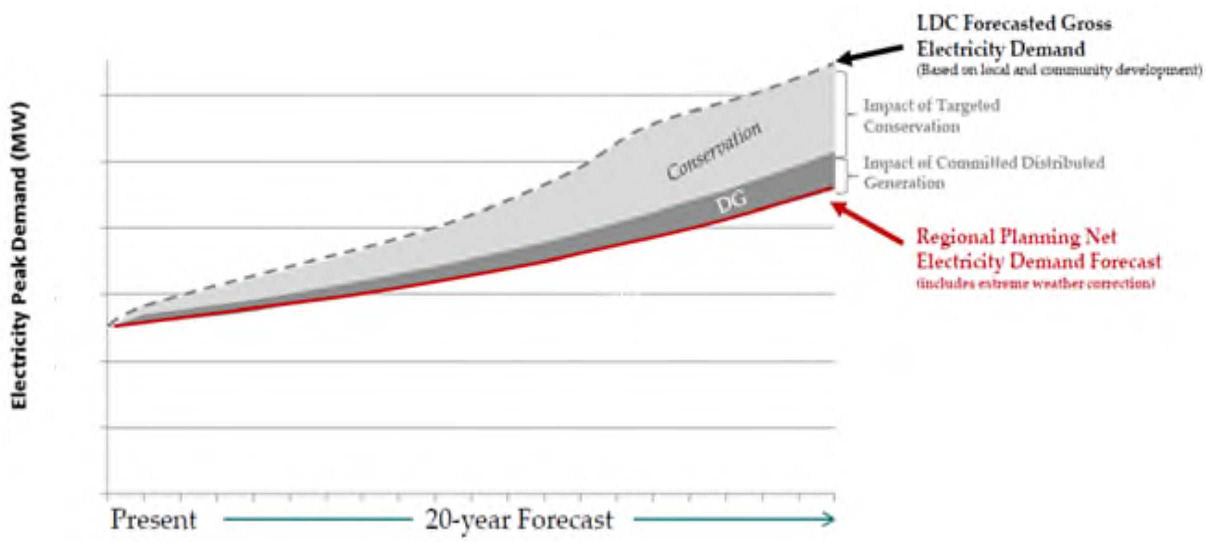


5.2 Demand Forecast Methodology

The steps taken to develop a 20-year IRRP peak demand forecast are depicted in Figure 4. Gross demand forecasts, which assume the weather conditions of an average year based on historical weather conditions (referred to as "normal weather"), were developed by the LDCs. These forecasts were then modified to reflect the peak demand impacts of provincial conservation targets and DG contracted through previous provincial programs such as Feed-In Tariff ("FIT") and microFIT, and adjusted to reflect extreme weather conditions in order to produce a reference forecast for planning assessments. This net forecast was then used to assess the electricity needs in the region.

Additional details related to the development of the demand forecast are provided in Appendix B. Though the Niagara IRRP forecast was created prior to October 2022, the Ontario Energy Board also since published a Load Forecast Guideline for regional planning, through the Regional Planning Process Advisory Group.

Figure 4 | Illustrative Development of Demand Forecast

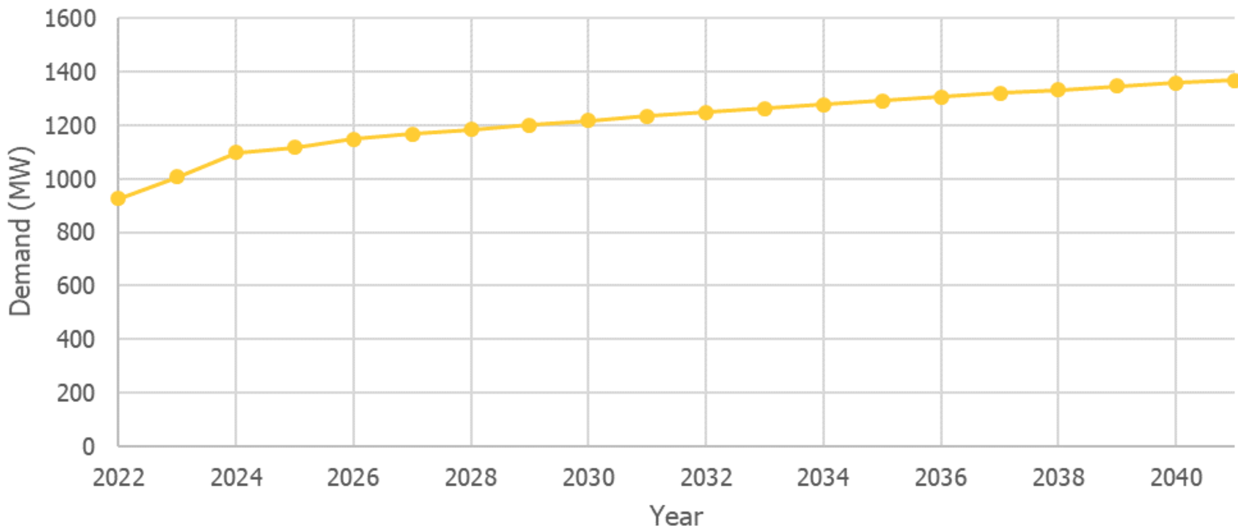


5.3 Gross LDC Forecast

Each participating LDC in the Niagara Region prepared gross demand forecasts at the station level, or at the station bus level for multi-bus stations. These gross demand forecasts account for increases in demand from new or intensified development, plus known connection applications. The LDCs cited alignment with municipal and regional official plans, and credited them as a source for input data. LDCs were also expected to account for changes in consumer demand resulting from typical efficiency improvements and response to increasing electricity prices ("natural conservation"), but not for the impact of future DG or new conservation measures (such as codes and standards and CDM programs), which are accounted for by the IESO (discussed in Section 5.4). The gross LDC forecast assumes median on-peak weather conditions, and station loading that is coincident to the region.

LDCs have a better understanding of future local demand growth and drivers than the IESO, since they have the most direct involvement with their customers, connection applicants, and municipalities and communities which they serve. The IESO typically carries out demand forecasting at the provincial level. More details on the LDCs' load forecast assumptions can be found in Appendix B.2 to B.8. Figure 5 below shows the total gross demand forecast provided by the LDCs for the Niagara Region.

Figure 5 | Total Gross Demand Forecast Provided by LDCs (Median Weather)[2]



5.4 Contribution of Conservation to the Forecast

Conservation and demand management is a clean and cost-effective resource that helps meet Ontario's electricity needs, and has been an integral component of provincial and regional planning. Conservation is achieved through a mix of codes and standards amendments, as well as CDM program-related activities. These approaches complement each other to maximize conservation results.

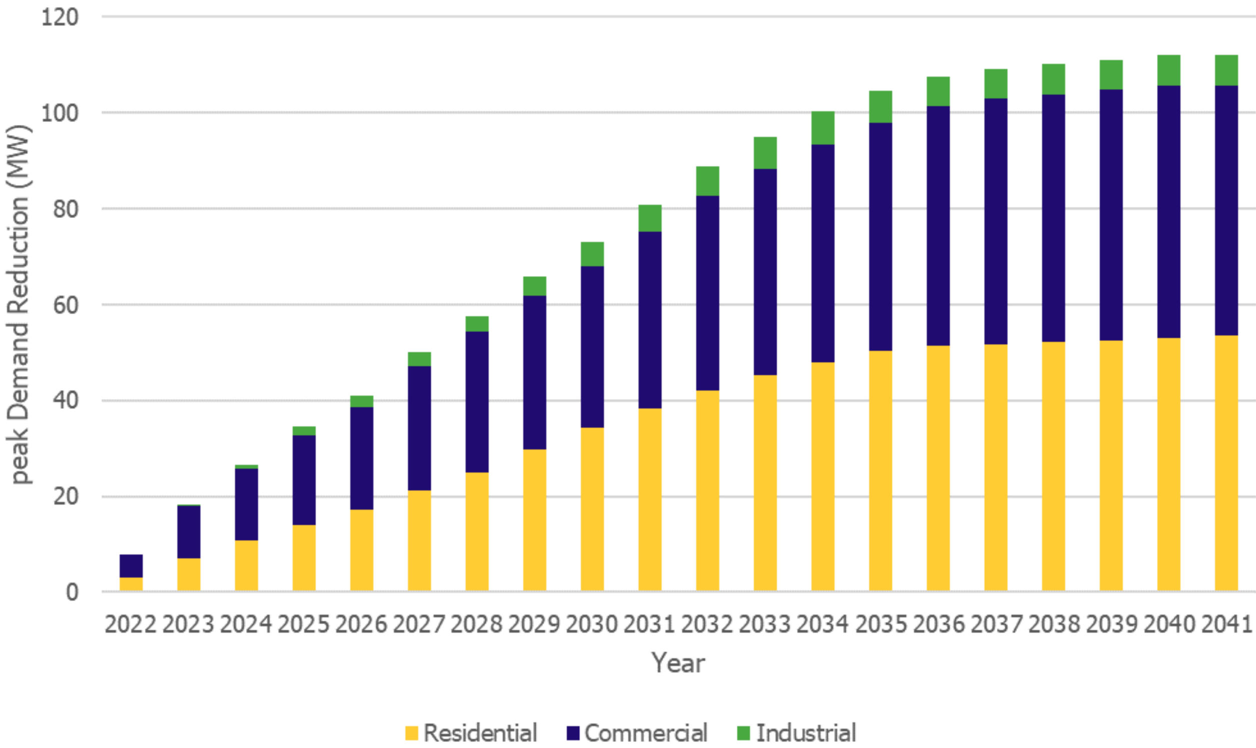
The estimate of demand reduction due to codes and standards are based on expected improvement in the codes for new and renovated buildings, and through regulation of minimum efficiency standards for equipment used by specified categories of consumers (i.e., residential, commercial and industrial consumers).

The estimates of demand reduction due to program-related activities account for the 2021-2024 CDM Framework, federal programs that result in electricity savings in Ontario, and forecasted long-term energy efficiency programs. The 2021 – 2024 CDM Framework is the main piece, in which the IESO centrally delivers programs on a province-wide basis to serve business and low-income customers, as well as Indigenous communities.

Figure 6 shows the estimated total yearly reduction to the demand forecast due to conservation (from codes, standards, and CDM programs) for each of the residential, commercial, and industrial consumers. Additional details are provided in Appendix B.9.

[2] Excludes existing transmission-connected industrial customers in the Niagara Region (historically contributing an average of 15 MW to the coincident peak demand).

Figure 6 | Total Forecast Peak Demand Reduction (Codes, Standards, and CDM Programs)

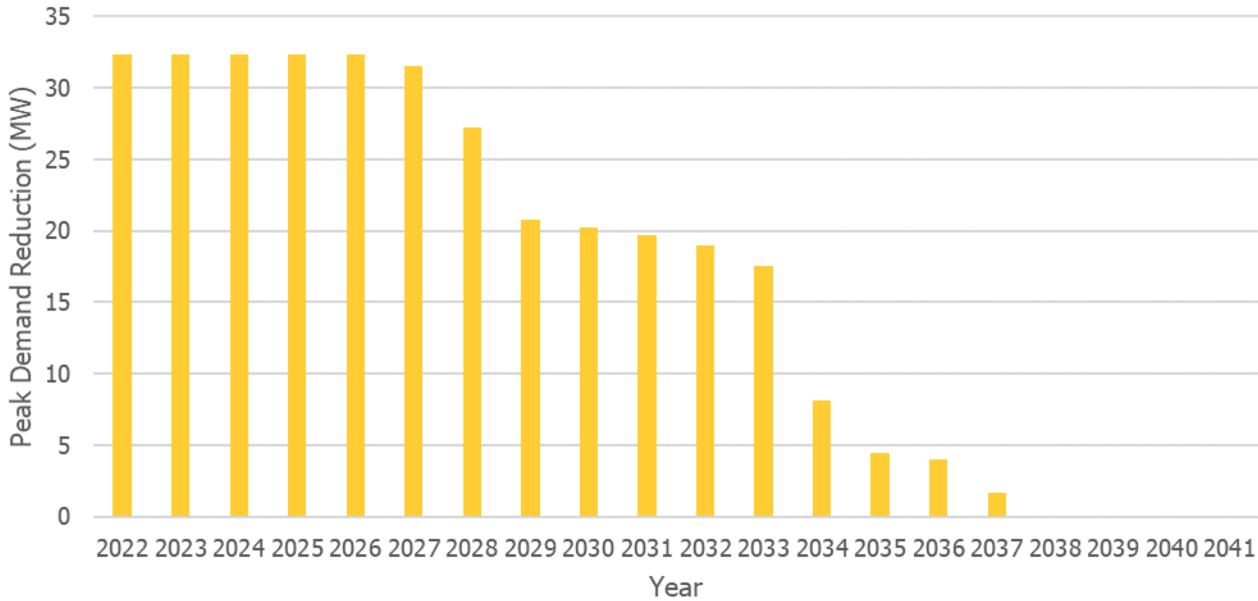


5.5 Contribution of Distributed Generation to the Forecast

In addition to conservation resources, DG in the Niagara Region is also forecast to offset peak-demand requirements. The introduction of Ontario's FIT Program increased the significance of distributed renewable generation which, while intermittent, contributes to meeting the province's electricity demands. The installed DG capacity by fuel type and contribution factor assumptions can be found in Appendix B.10. Most of the total contracted installed DG capacity in the Niagara Region is solar, wind, and waterpower, with some biogas, landfill gas, and natural gas facilities.

After reducing the demand forecast due to conservation, as described in Section 5.4, the forecast is further reduced by the expected contribution from contracted DG. Figure 7 shows the impact of DG on reducing the Niagara Region demand forecast. Note that any facilities without a contract with the IESO are not currently included in the DG peak demand reduction forecast.

Figure 7 | Peak Demand Reduction to Demand Forecast, Due to DG



In the long term, the contribution of DG is expected to diminish as their contracts expire. A total of 32 MW of peak contribution is identified for the Niagara Region in 2022, reducing throughout the 2030s to 0 MW by 2038. This reduction is reflected in the high forecast scenario (see Section 5.7 for more details on its development and assumptions), but not the reference forecast. Rather, the reference Niagara IRRP forecast assumes a constant contribution of approximately 32 MW each year for the entire study period. This aligns with the Technical Working Group decision to assume that already-existing DG facilities with expired contracts will continue to offset demand.

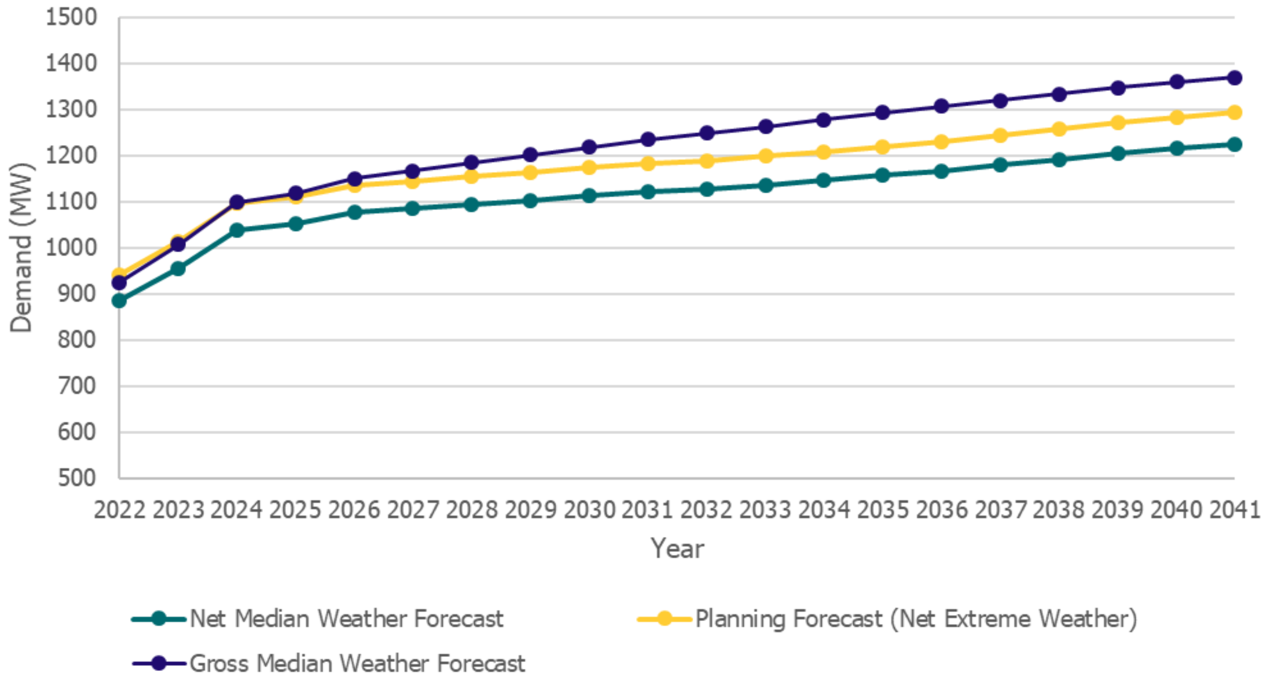
5.6 Net Extreme Weather ("Planning") Forecast

The net extreme weather forecast, also known as the "planning" forecast, is created by adjusting the net median weather forecast (the gross demand forecast, plus the forecast DG and conservation impacts as described above) for extreme weather conditions. The weather correction methodology is described in Appendix B.1.

Note that this planning forecast is coincident, meaning that each station forecast reflects its expected contribution to the regional peak demand level. This supports the identification of need dates for regional needs that are driven by more than one station. For station-specific needs, the non-coincident forecast is calculated by applying a non-coincidence factor. The factor is based on the historical non-coincident peaks of each station compared to the station's contribution to the region's coincident peaks over the past six years.

The coincident net extreme weather forecast for the Niagara Region is shown in Figure 8 below.

Figure 8 | Net Extreme Weather ("Planning") Forecast for the Niagara Region[3]



5.7 High Forecast Scenario

The Technical Working Group opted to develop a high forecast sensitivity scenario for the Niagara Region. This higher demand scenario is to take into account a variety of factors that could drive demand higher over the next 20 years, including but not limited to: electric vehicle charging infrastructure, electrified space heating installations, unanticipated new industrial customers, or general higher-than-expected growth. However, the Technical Working Group did not have specific end-use data available to develop the high forecast. Instead, the DG contribution to peak (as described in Section 5.5) was removed according to contract expiries, resulting in approximately 3% higher total regional load by 2041 when compared to the reference planning forecast. The impact on stations with greater contracted DG is higher.

The high forecast also included several large industrial customers whose connection was uncertain at the time of finalizing the reference forecast. These include customers that members of the Technical Working Group were aware of and liaising with, as well as customers that initiated a System Impact Assessment with the IESO during the Niagara IRRP development. In total, another 132 MW was added due to this assumption, when compared to the reference planning forecast. This is shown in Figure 9.

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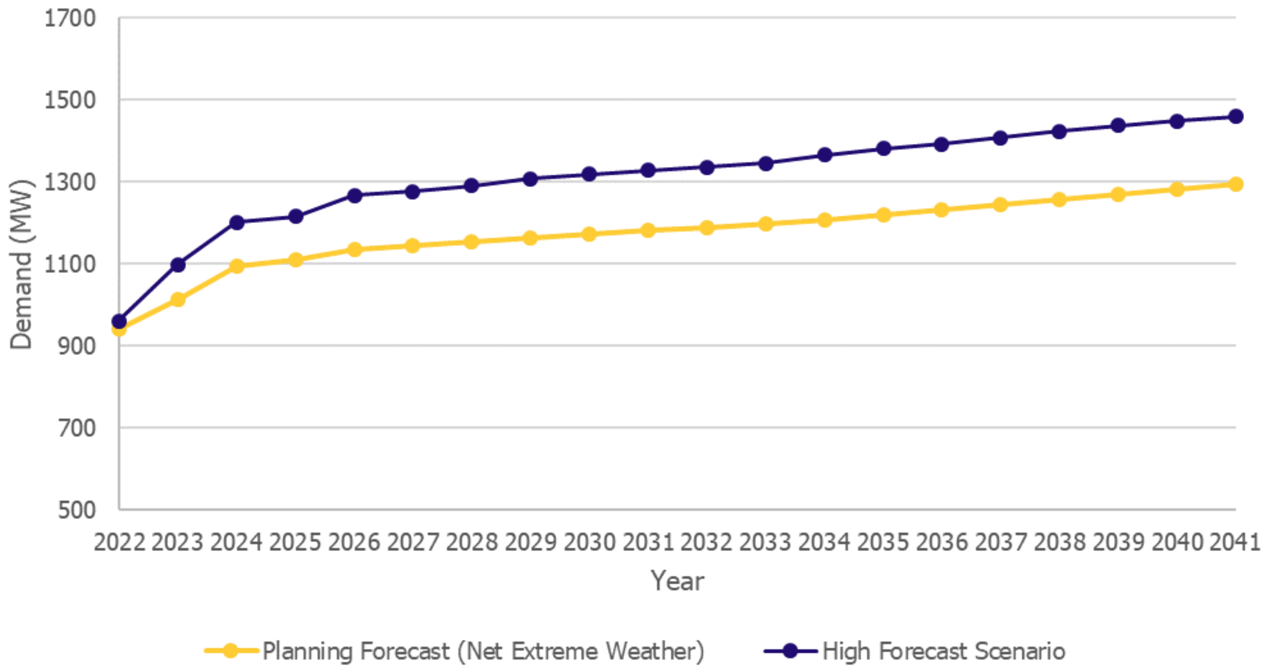
[3] See footnote 2.

Figure 9 | High Forecast Scenario for the Niagara Region[4]



The higher demand scenario was not used to drive any firm recommendations for this IRRP; however, it was used to help the Technical Working Group identify where the future pinch points may be and when they could materialize. This information can also be useful for communities conducting Community Energy Plans, for the Technical Working Group in determining areas to monitor in future planning cycles, and for communities and stakeholders as they think about various projects in the region. Moreover, during this IRRP, the Technical Working Group also considered the flexibility of evaluated options to accommodate greater long-term growth. This is later described in Section 7.

5.8 Hourly Forecast Profiles

In addition to the annual peak forecast, hourly load profiles (8,760 hours per year over the 20-year forecast horizon) for certain stations with identified needs were developed to characterize their needs with finer granularity. The profiles were based on historical load data, adjusted for variables that impact demand such as calendar day (i.e., holidays and weekends) and weather. The profiles were then scaled to match the IRRP peak planning forecast for each year. As described later in Section 7, these profiles were used to quantify the magnitude, frequency, and duration of needs to better evaluate the suitability of generation and distributed energy resource options.

Additional load profile details including hourly heat maps for each need can be found in Appendix D. Note that this data is used to roughly inform the overall energy requirements needed to develop and evaluate alternatives; it cannot be used to deterministically specify the precise hourly energy requirements. Real-time loading is subject to various factors like actual weather, customer operation strategies, and future customer segmentation. Demand patterns can change significantly as consumer behaviour evolves, new industries emerge, and trends like electrification are more widely adopted. Hence, these hourly forecasts are only used to select suitable technology types and roughly

[4] See footnote 2.

estimate costs for the needs and options studied in the IRRP. The Technical Working Group will continue to monitor forecast changes as part of implementation of the plan.

6. Needs

6.1 Needs Assessment Methodology

Based on the planning demand forecast, system capability, the transmitter's identified asset replacement plans, and the application of ORTAC, NERC TPL-001-4, and Northeast Power Coordinating Council ("NPCC") Directory #1 standards, the Technical Working Group identified electricity needs in the near-, medium- and long-term timeframes. These needs can be categorized according to the following:

- **Station Capacity Needs** describe the electricity system's inability to deliver power to the local distribution network through the regional step-down transformer stations during peak demand. The capacity rating of a transformer station is the maximum demand that can be supplied by the station and is limited by station equipment. Station ratings are often determined based on the 10-day Limited Time Rating ("LTR") of a station's smallest transformer under the assumption that the largest transformer is out of service. A transformer station can also be more limited by downstream or upstream equipment, i.e., breakers, disconnect switches, low-voltage bus or high voltage circuits.
- **Supply Capacity Needs** describe the electricity system's inability to provide continuous supply to a local area during peak demand. This is limited by the LMC of the transmission supply. The LMC is determined by evaluating the maximum demand that can be supplied to an area after accounting for limitations of the transmission elements (i.e., a transmission line, group of lines, or autotransformer), when subjected to contingencies and criteria prescribed by ORTAC, TPL-001-4, and NPCC Directory #1. LMC studies are conducted using power system simulation analyses.
- **Asset Replacement Needs** are identified by the transmitter by an asset condition assessment, which is based on a range of considerations such as equipment deterioration due to aging infrastructure or other factors; technical obsolescence due to outdated design; lack of spare parts availability or manufacturer support; and/or potential health and safety hazards, etc. Replacement needs identified in the near- and early mid-term timeframe would typically reflect more condition-based information, while replacement needs identified in the medium to long term are often based on the equipment's expected service life. As such, any recommendations for medium- to long-term needs should reflect the potential for the need date to change as condition information is routinely updated.
- **Load Security and Restoration Needs** describe the electricity system's inability to minimize the impact of potential supply interruptions to customers in the event of a major transmission outage, such as an outage on a double-circuit tower line resulting in the loss of both circuits. Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. Load restoration describes the electricity system's ability to restore power to those affected by a major transmission outage within reasonable timeframes. The specific load security and restoration requirements are prescribed by Section 7 of ORTAC.

Technical study results for the Niagara IRRP can be found in Appendix G. The needs identified are discussed in Sections 6.2 – 6.5 below.

6.2 Station Capacity Needs

In the near/mid-term, there are summer station capacity needs at Beamsville TS, Murray TS, Crowland TS, and Niagara West MTS. In the longer term, there are station capacity needs at Carlton TS, Vineland DS, and Kalar MTS. Table 2 below summarizes transformer capacity limitations for the Niagara Region.

Table 2 | Summary of Station Capacity Needs in the Niagara Region

Need	10-day LTR Rating (MW)[5]	Need Date[6]	Size of Need by 2041
Beamsville TS	57	2022	44
Murray TS (T11/T12)	72	2022	14
Crowland TS	96	2022	25
Niagara West MTS	60	2026	22
Carlton TS	94	2028	11
Kalar MTS	68	2030	7
Vineland DS	25	2030	3

6.2.1 Beamsville TS, Niagara West MTS, and Vineland DS

The three stations supplying the Lincoln, West Lincoln, and Grimsby areas (Beamsville TS, Niagara West MTS, and Vineland DS) are forecast to reach their individual station limits, as well as their collective limit (sum of their LTRs). Beamsville TS and Vineland DS each comprise two 115 kV/27.6 kV transformers, with summer LTRs of 57 MW and 25 MW, respectively. The Beamsville TS capacity need exists today (Figure 10), whereas the Vineland DS need is forecast to start in 2030 (Figure 12). Niagara West MTS consists of two 230 kV/27.6 kV transformers, with a summer LTR of 60 MW and a need beginning in 2026 (Figure 11). Cumulatively, the capacity need at these three stations grows to 57 MW by 2041 (Figure 13).

[5] Assuming a 0.9 power factor.

[6] Based on non-coincident station forecasts, as explained in Section 5.6.

Figure 10 | Beamsville TS Capacity Need

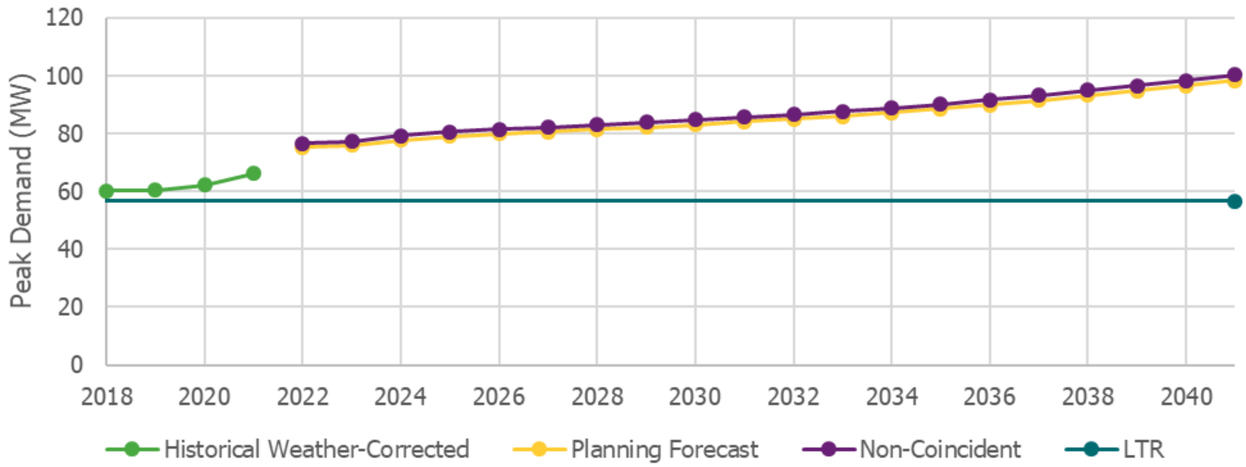


Figure 11 | Niagara West MTS Capacity Need

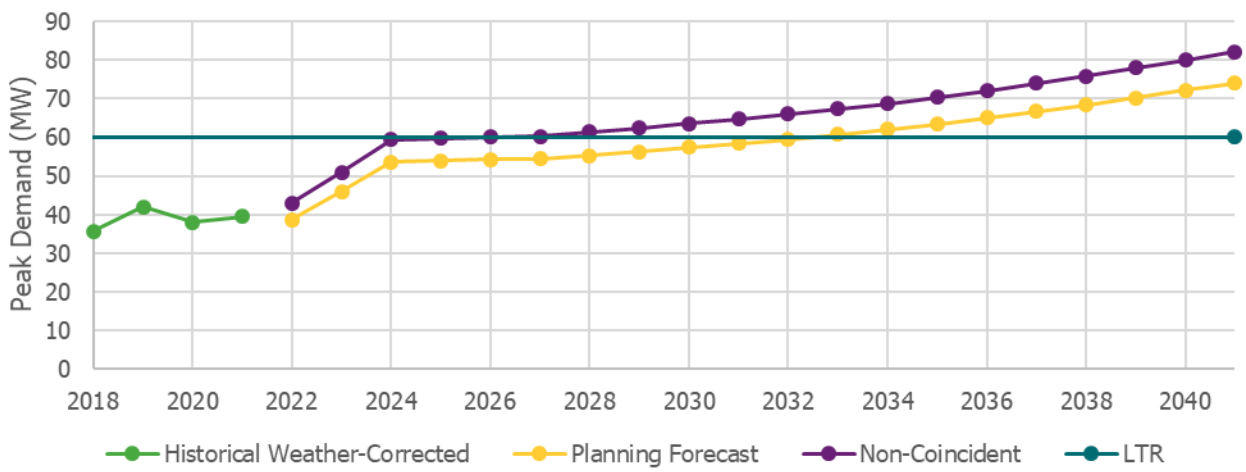


Figure 12 | Vineland DS Capacity Need

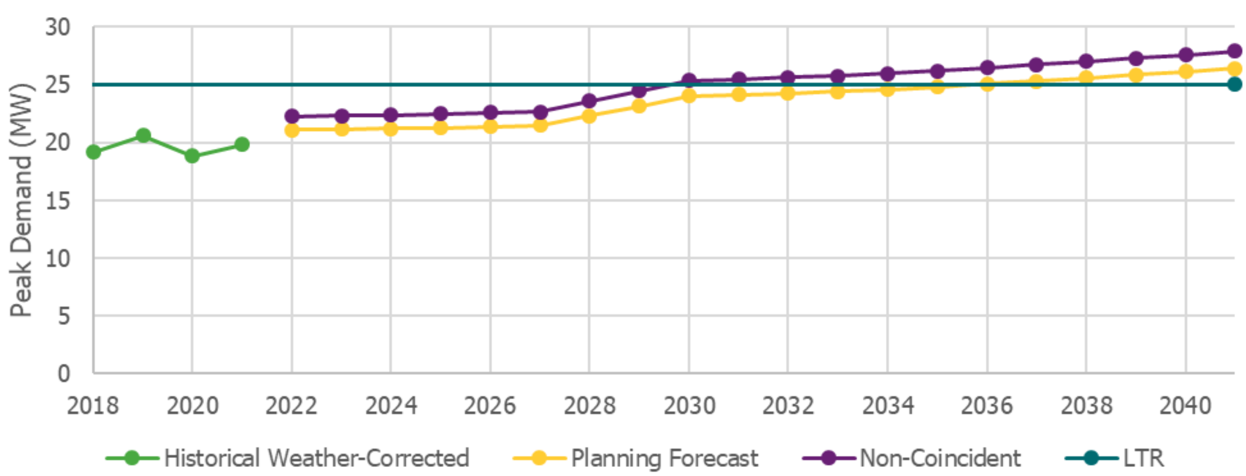
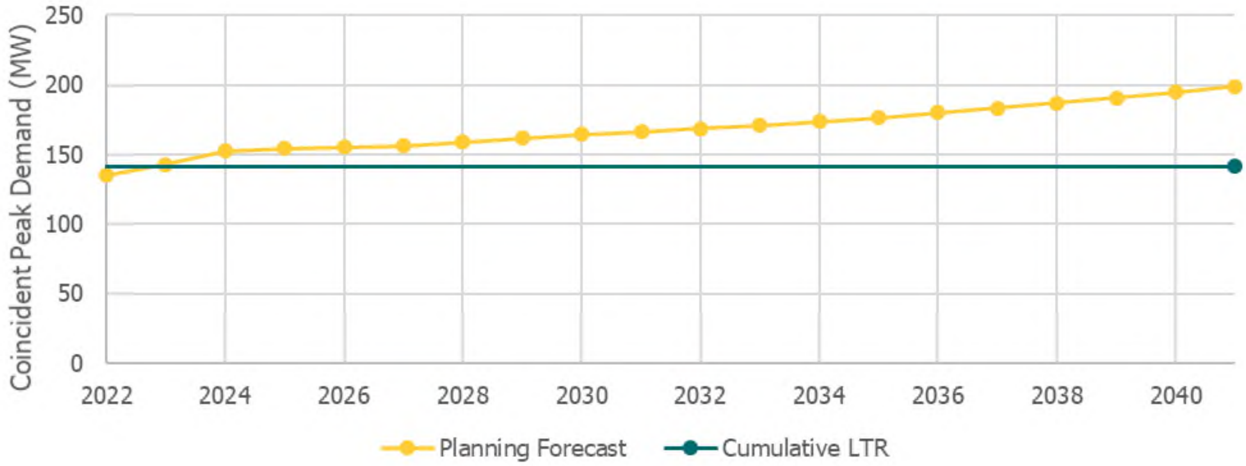


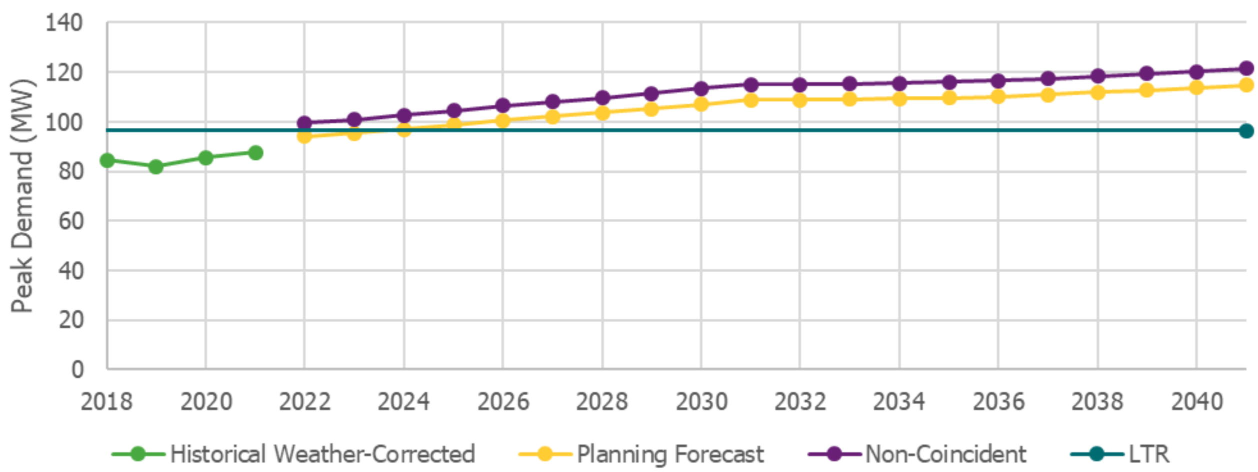
Figure 13 | Beamsville TS, Vineland DS, and Niagara West MTS Cumulative Coincident Capacity Need



6.2.2 Crowland TS

Supplying Welland, Crowland TS is forecast to reach its summer station capacity limit in 2022 and grow to a 25 MW need by 2041. This station comprises two 115 kV/27.6 kV transformers with an LTR of 96 MW.

Figure 14 | Crowland TS Capacity Need



6.2.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

Carlton TS and Kalar MTS each comprise two 115 kV/13.8 kV transformers, with summer LTRs of 94 MW and 68 MW, respectively. Carlton TS is forecast to reach capacity starting in 2028 (Figure 15) while the Kalar MTS need arises in 2030 (Figure 16). Each need will increase to 11 MW and 7 MW, respectively, by 2041. Murray TS consists of four 230 kV/13.8 kV transformers; T11 and T12 have a summer LTR of 72 MW, whereas T13 and T14 are rated to 77 MW. The T11/T12 capacity need exists today, growing to 14 MW by 2041 (Figure 17).

Figure 15 | Carlton TS Capacity Need

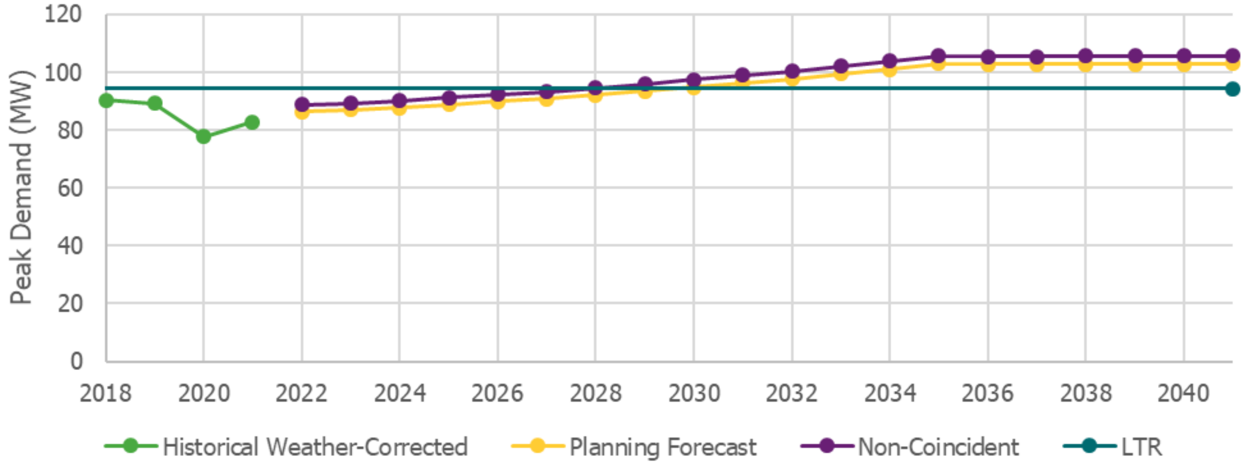


Figure 16 | Kalar MTS Capacity Need

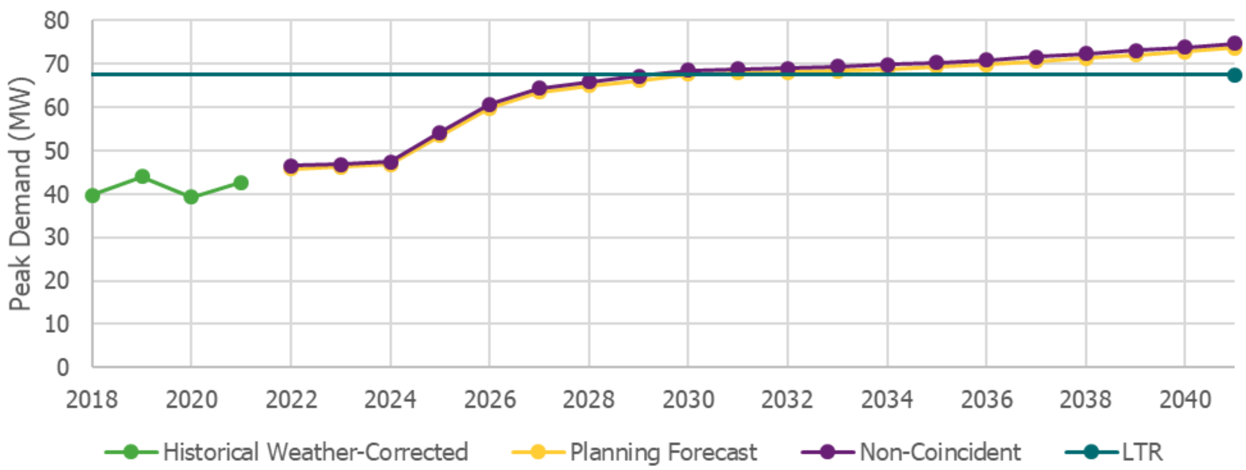


Figure 17 | Murray TS (T11/T12) Capacity Need

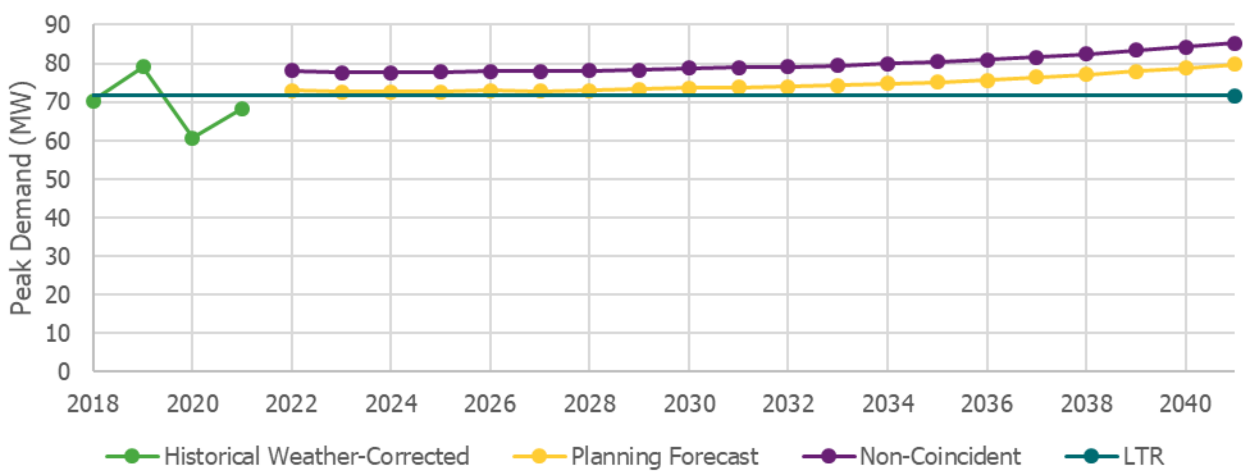
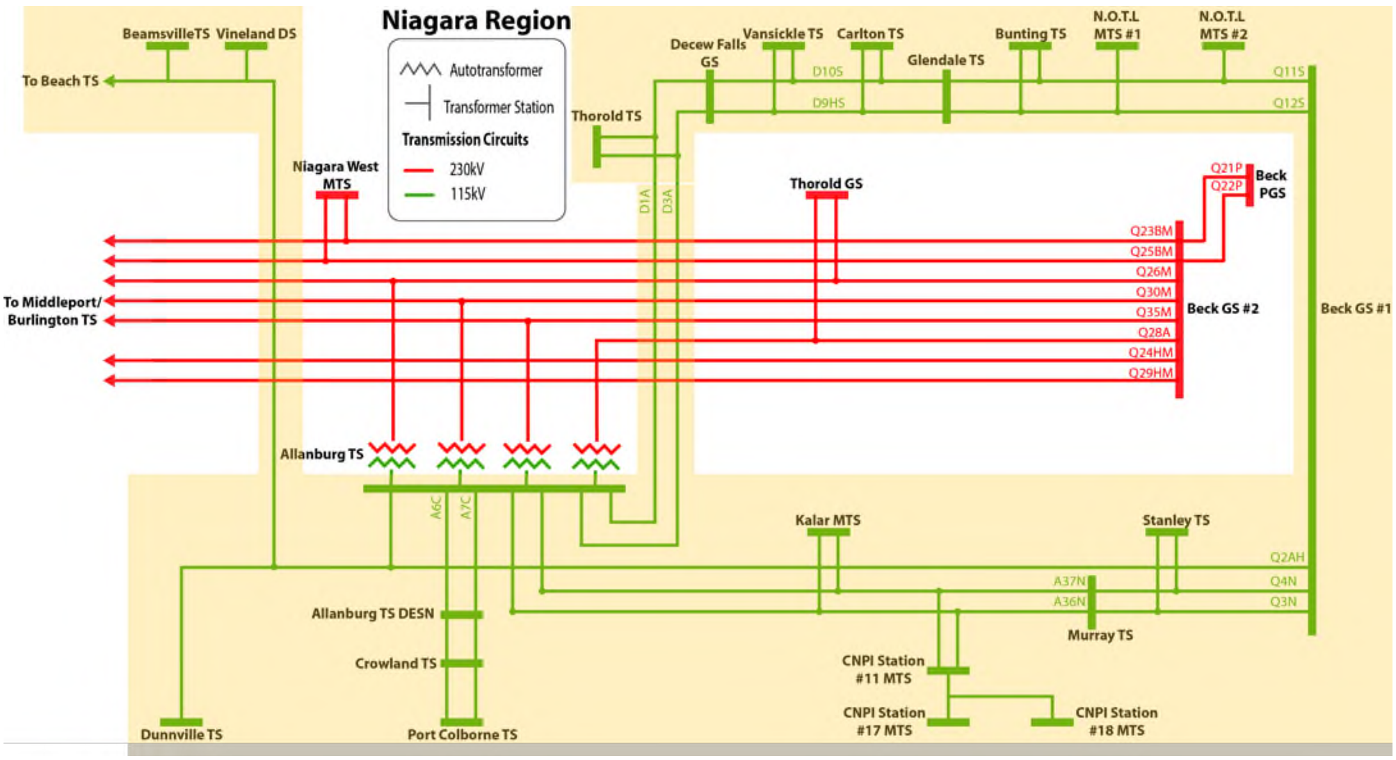


Figure 15 to Figure 17 demonstrate the non-coincident peak demand forecasts at these stations compared to their individual LTRs. Note that these station capacity needs have been presented together in this sub-section, since this IRRP is not yet recommending infrastructure reinforcements to address them. Section 7.2.1.3 describes this in more detail.

6.3 Supply Capacity Needs

The majority of load in the Niagara Region is supplied through its 115 kV transmission sub-system, which in turn is supplied from the 230/115 kV autotransformers at Allanburg TS, Sir Adam Beck GS #1, and Decew Falls GS. The LMC of the 115 kV sub-system is therefore limited by the capability at Allanburg TS under the various planning scenarios and applicable contingencies. The sub-system is demonstrated in Figure 18.

Figure 18 | Niagara Region's 115 kV Sub-System (Highlighted Yellow)

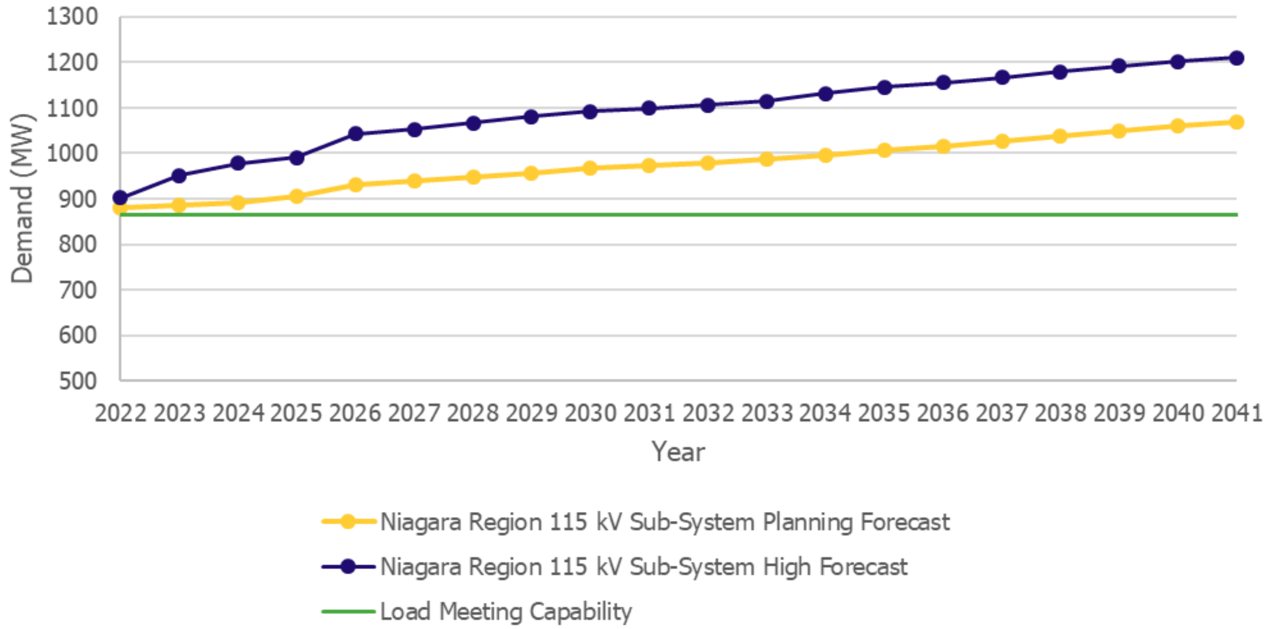


The LMC of the Niagara 115 kV sub-system, presented in Figure 19 against the forecast load, reflects limitations of the existing transmission system. Under certain outage and contingency conditions (such as contingencies impacting two circuits between Beck GS #2 and Middleport/Burlington, or Beck GS #1), the lowest-rated Allanburg autotransformer is overloaded and is the first limiting phenomenon that restricts total reliable supply into the 115 kV sub-system. However, the LMC for this area can also be restricted by other phenomena, including the thermal capability of a section of Q28A during other contingency events and specific generation outage conditions. There are further, more local restrictions within this sub-system too – such as thermal constraints limiting the supply to loads between Allanburg TS and Beck GS #1 through the 115 kV circuits.[7] All of these transmission limits are described in Appendix G.

[7] This particular need, which occurs under outage conditions, could be addressed through permissible operational control actions and would be impacted by a customer's System Impact Assessment that is ongoing at the time of regional planning.

Between 2018 – 2021, the 115 kV sub-system has had a peak coincident weather-corrected load of up to approximately 830 MW. With the reference planning forecast, the 115 kV sub-system load increases such that the supply capacity need grows to approximately 200 MW by 2041; under the high scenario, it is about 340 MW.

Figure 19 | Niagara Region 115 kV Supply Capacity Need



6.4 Asset Replacement Needs

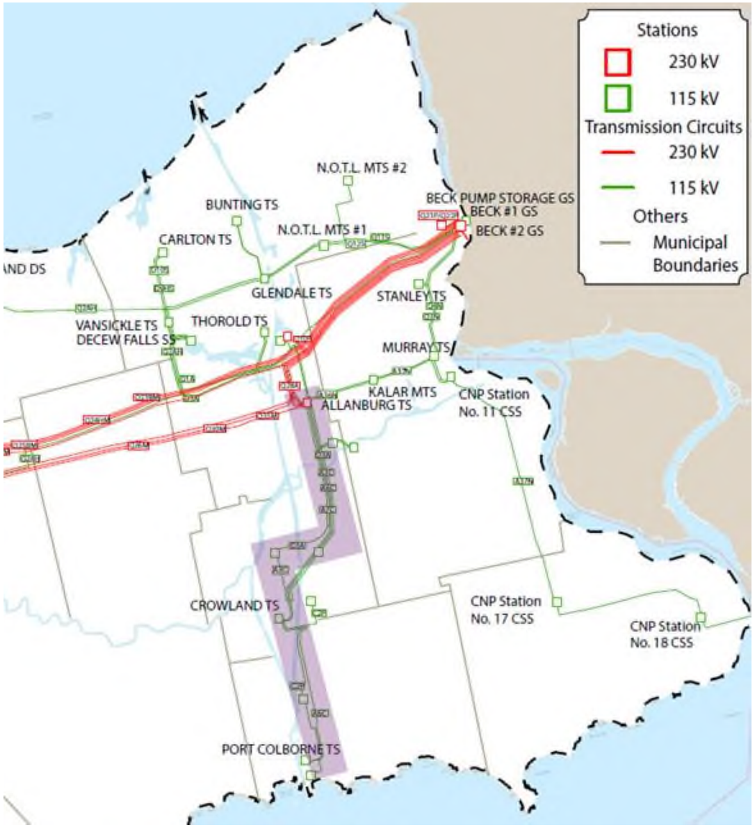
At the time of the Niagara Region Needs Assessment, Hydro One identified a number of assets requiring replacement in the next 10 years. This included Crowland TS, whose transformers were originally scheduled to be replaced with like-for-like 115/27.6 kV 83 megavolt ampere ("MVA") units before 2026. As described in the Niagara Region Scoping Assessment, the Technical Working Group agreed that sustainment plans identified by Hydro One would be assumed to proceed as described in the Needs Assessment – unless an opportunity arose for "right-sizing".

Through the development of the IRRP, during which a more comprehensive demand forecast was created and extended to a 20-year planning horizon, and additional needs were identified or refined, the Crowland TS like-for-like replacement plan was reconsidered. This need and its relevance to the other regional needs are described further in Section 7.4.

6.5 Load Security Needs

The circuits designated as A6C/A7C form a 115 kV double-circuit line from Allanburg TS to Crowland TS, before supplying Port Colborne TS as A6C and C2P. These circuits also serve a number of transmission-connected industrial customers that are south of Allanburg TS, primarily east of the Welland Canal. Figure 20 provides an overview of this portion of the transmission system in the Niagara Region.

Figure 20 | Niagara Region Transmission System: A6C/A7C (Highlighted Purple)



The aforementioned stations and transmission-connected customers on the A6C/A7C circuits are included in the Allanburg Load Rejection Scheme; operational actions are taken to disconnect these loads in the event of certain contingencies to prevent voltage decline upon the coincidental loss of Allanburg T1 and T2. At the 2022 expected load levels on the A6C/A7C circuits, a double contingency on the Q26M and Q28A circuits will trigger over 180 MW of load being disconnected from the system. This is a violation of Section 7.1 of the ORTAC, which specifies that only up to 150 MW of planned load curtailment is permissible under these conditions. The load supplied by A6C/A7C is also expected to grow throughout the study period (i.e., up to 2041). By 2041, it is expected that the load security need will grow to approximately 75 MW in excess of the permissible amount. More details regarding this load security need are provided in Appendix G.

6.6 Summary of Identified Needs

Below is an overview of all needs identified in this Niagara IRRP.

Table 3 | Summary of Needs in the Niagara Region

Need	Need Date
Beamsville TS Station Capacity	2022
Murray TS (T11/T12) Station Capacity	2022
A6C/A7C Load Security Need	2022

Need	Need Date
Niagara 115 kV Sub-System Supply Capacity	2022
Crowland TS Station Capacity	2022
Crowland TS Asset Replacement	2026
Niagara West MTS Station Capacity	2026
Carlton TS Station Capacity	2028
Kalar MTS Station Capacity	2030
Vineland DS Station Capacity	2030

7. Plan Options and Recommendations

This section describes the options considered and recommendations to address the needs in the Niagara Region. In developing the plan, the Technical Working Group considered a range of integrated options. Considerations in assessing alternatives included maximizing use of existing infrastructure, provincial electricity policy, feasibility, cost, and consistency with longer-term needs in the area.

Generally speaking, there are two approaches for addressing regional needs that arise as electricity demand increases:

- Build new infrastructure to increase the LMC of the area. These are commonly referred to as “wires” options and can include things like new transmission lines, autotransformers, step-down transformer stations, voltage control devices, or upgrades to existing infrastructure. Wires options may also include control actions or protection schemes that influence how the system is operated to avoid or mitigate certain reliability concerns.
- Install or implement measures to reduce the net peak demand to maintain loading within the system’s existing LMC. These are commonly referred to as “non-wires” options and can include things like local utility-scale generation, distributed energy resources (including distribution-connected generation and demand response), or CDM.

Section 7.1 begins with a more in-depth overview of all option types considered in IRRPs. Section 7.2 describes the screening approach used to assess which needs would be best suited for a more detailed assessment for non-wires options. Subsequently, Section 7.3 to Section 7.5 present the options that were ultimately developed and evaluated (including a cost comparison) before the Technical Working Group made a recommendation.

7.1 Options Considered in IRRPs

Wires options are always considered in regional planning, and are developed by designing transmission reinforcements or control actions that are appropriate for the specific limiting phenomenon (voltage, thermal, stability, etc) of each need. These are identified through discussions with the Technical Working Group.

While traditional wires infrastructure is always a viable option for regional needs, some non-wires options are more suitable for specific need types and characteristics. Hence, to select and size suitable generation and other non-wires options, additional work is required – including creation of an hourly load profile, as described in Section 5.8. The most suitable technology type and capacity is chosen by examining the “unserved energy” profile, which is the hourly demand above the existing LMC. The profile indicates the duration, frequency, magnitude, and total energy associated with each need. Some of these characteristics are shown visually in Appendix D for the Niagara Region needs.

High-level cost estimates for wires options are usually provided by the transmitter. In contrast, cost estimates for generation and other non-wires options are based on benchmark capital and operating cost characteristics for each resource type and size. Generally speaking, the most cost-effective transmission-connected options for meeting local needs in the Niagara Region are resources with a performance and costs on par with simple cycle gas turbines. New natural gas-fired generation was considered in the economic analysis for illustrative purposes, as it was representative of the lowest cost generation option. Energy storage, such as lithium nickel manganese cobalt oxide batteries, are also becoming cost-competitive due to declining technology costs and the expectation of carbon prices increasing in line with federal policy. Other energy resources (which are typically distribution-connected) are also considered.

CDM measures can also help decrease the net electricity demand. Centrally delivered energy efficiency measures under the 2021-2024 CDM Framework and Save on Energy brand are already included in the load forecast, as discussed in the Section 5.4. As part of this current Framework, the IESO was directed to deliver a new program to address regional and/or local system needs. The Local Initiative Program is now one tool that is available to target the delivery of additional CDM savings at specific areas of the province with identified system needs. LDCs can also use the Ontario Energy Board's CDM Guidelines to leverage distribution rates to help address distribution and transmission system needs using non-wires alternatives.[8] Generally, incremental CDM measures are suitable for needs where growth is slow and the magnitude of the overload relative to the total demand is very small (i.e., on the order of few percent per year). These considerations are discussed further in Section 7.2, as part of the screening of options that was conducted.

For both wires and non-wires options, the upfront capital and operating are compiled to generate levelized annual capacity costs ($/kW-year). A cash flow of the levelized costs for the options are compared over the lifespan of the wires option (typically 70 years for transmission infrastructure). The non-wires options also include any system capacity benefit that they could contribute to provincial resource adequacy needs, ensuring that they are both sized to address the local need and are comparable to the wires options. The net present value (in 2021 CAD dollars) of these levelized costs are the primary basis through which feasible options are compared.

It is important to recognize that there is a significant error margin around costs estimates at the planning stage, as they are only intended to enable comparison between options during the IRRP. The RIP (which is conducted after the IRRP) performs additional detailed analysis and allows the opportunity to refine wires cost estimates before implementation work begins. The IESO continues to participate in the Technical Working Group during the RIP and revisits these recommendations if costs estimates differ significantly. Furthermore, in cases where other barriers downstream of the regional planning process (i.e., regulatory frameworks for cost-sharing and recovery, or operationalization to meet local reliability constraints) impede the adoption of some of these cost-effective options, pilot or demonstration projects can be explored.[9]

The list of assumptions made in the economic analysis can be found in Appendix F.

7.2 Screening Options

As explained in Section 7.1, an array of options can be developed to meet local needs during an IRRP, but options are ultimately evaluated to recommend the most cost-effective and technically

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[8] More information about the CDM Guidelines is available on the Ontario Energy Board's website.

[9] Barriers to non-wires alternatives and recommendations to address them were a part of the Regional Planning Process Review.

feasible solution. This process is complemented by considerations for stakeholder preferences and feedback.

Screening occurs early in the IRRP study after local reliability needs are known but before options analysis. It helps direct time-intensive aspects of detailed non-wires analysis (hourly need characterization, options development, financial analysis, and engagement) towards the most promising options. The three-step, high-level approach is shown in Figure 21, and the results of its application to the Niagara IRRP needs are summarized in Table 4 and then further described in the sections below. More details on the steps and inputs used in the screening mechanism can be found in Appendix C.

Figure 21 | IRRP Screening Mechanism

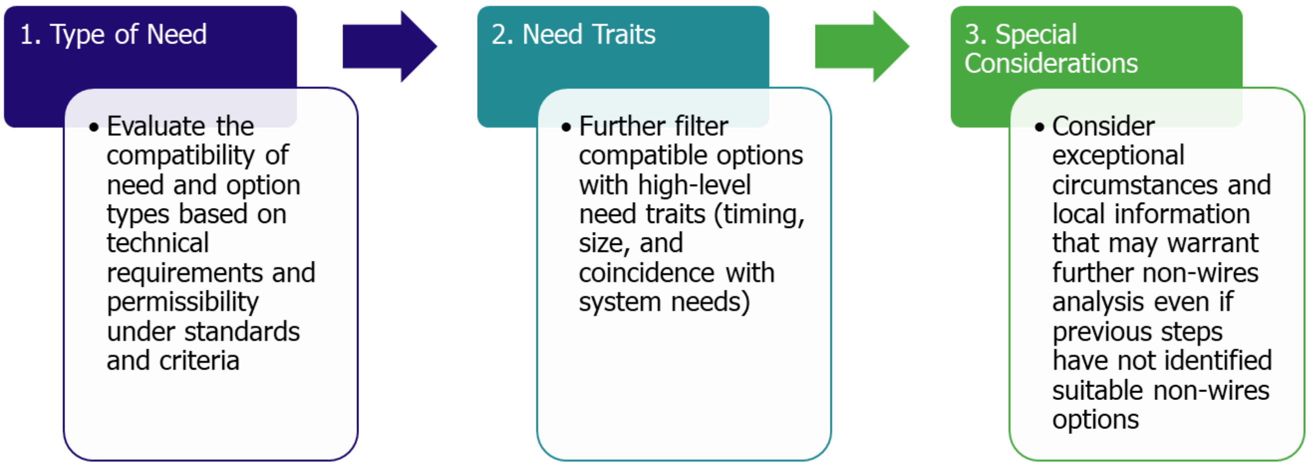

Table 4 | Results of Niagara IRRP Screening

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Beamsville TS	Wires, demand response ("DR"), DG, CDM	Transmission-connected generation
Station capacity	Vineland DS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Crowland TS	Wires, DR, DG, CDM	Transmission-connected generation
Station capacity	Kalar MTS	Wires, CDM	Transmission-connected generation, DR, DG
Station capacity	Carlton TS	Wires	All non-wires

Need Type	Impacted Element	Options Screened In	Options Screened Out
Station capacity	Murray TS (T11/T12)	Wires	All non-wires
Supply capacity	Niagara 115 kV sub-system	Wires, transmission-connected generation, CDM	DR, DG
Asset replacement	Crowland TS	Coordinated with the Crowland TS station capacity need	Coordinated with the Crowland TS station capacity need
Load security	Load supplied by A6C/A7C circuits	Wires	All non-wires

7.2.1 Non-Wires Options for the Capacity Needs

Based on the nature of the need, Step 1 of the screening mechanism identifies that in general, non-wires options can resolve supply and station capacity needs by reducing net load in the affected area. For station capacity needs specifically, these options must be resources that are connected downstream of the limiting step-down transformer. The following sections outline when Steps 2 and 3 of the screening resulted in further analysis of non-wires options.

7.2.1.1 Beamsville TS, Niagara West MTS, and Vineland DS

As described previously in Section 6.2.1, there are forecast station capacity needs at Beamsville TS, Niagara West MTS, and Vineland DS, as well as a collective capacity shortfall in the area supplied by the three stations. Though eventually considered together given their geographic proximity, Beamsville TS and Vineland DS were screened independently. For Beamsville TS, with its large near-term capacity need, all applicable non-wires options were considered. Conversely, for the small long-term need at Vineland DS, the focus (in terms of a non-wires option) was on incremental CDM.

At the time of screening, the Technical Working Group did not identify a station capacity need at Niagara West MTS; this occurred later in the IRRP development when the forecast was updated by Grimsby Power. Hence, formal screening was not conducted for Niagara West MTS – but this IRRP does ultimately include recommendations that address its need (see Section 7.3).

7.2.1.2 Crowland TS

For Crowland TS, all applicable non-wires options were developed in further detail. Initially, at the time of the screening, the Crowland TS and Kalar MTS station needs were approached together given their perceived geographic proximity. However, recommendations were eventually made for these stations separately after considering factors that made an integrated approach impractical. These factors include distribution voltage level differences, distance to supply forecast growth areas, and misaligned capacity need timing between the two stations.

7.2.1.3 Carlton TS, Kalar MTS, and Murray TS (T11/T12)

For some needs, further analysis of non-wires is not warranted if there is the high potential for an inexpensive and simple wires alternative that maximizes the use of existing infrastructure. This can include load transfers or control actions that are sufficient to meet the need.

This was the case for the station capacity needs at Carlton TS and Murray TS (T11/T12). At the time of screening, Alectra Utilities indicated plans to reallocate some forecast demand at Carlton TS to a nearby station with additional capacity (Bunting TS). At Murray TS, NPEI is supplied by both T11/T12 and T13/T14. While forecast demand for T11/T12 exceeds its LTR, there is sufficient remaining capacity at T13/T14.[10] Managing the load distribution between the four transformers at Murray TS is expected to address the need at T11/T12.

For the small long-term need at Kalar MTS, incremental CDM was screened in for additional analysis.

7.2.1.4 Niagara 115 kV Sub-System Supply

Due to the nature of supply capacity needs, most non-wires options can be potential solutions – either alone or as a part of an integrated package of recommendations. However, for the Niagara 115 kV sub-system, the magnitude of the capacity need was large enough that the option development focused on transmission-connected generation or storage, with some consideration for additional locally targeted CDM.

Other non-wires options such as DR and DG were screened out from further analysis for a number of reasons. For instance, the connection of DG (regardless of fuel type) is subject to equipment limitations such as minimum loading, feeder capacity, station thermal capacity, and short circuit requirements. With an approximately 200 MW supply capacity need, the amount of incremental DG required would not be able to connect to a single transformer station in the Niagara Region, and would be unlikely to be accommodated, coordinated, and operated across multiple stations to meet the local supply constraint.[11] Recall that existing contracted DG output at peak was already accounted for during the development of the net demand forecast.

Similarly, DR was screened out due to the magnitude of the Niagara 115 kV supply capacity need. Though DR can be considered as a potential option to the extent that loads in the area can be curtailed during peak hours, the amount of DR that has historically been acquired for system capacity needs can help indicate this option's feasibility. For the 2021 summer obligation period in the capacity auction, approximately 20 MW of total capacity cleared for the Niagara zone. These past auction results provide context as to the scale of demand response that would be required to address the Niagara supply capacity need; this is unlikely to be achievable in the near-term. It is also worth noting that the Capacity Auction acquires resources designed to meet provincial adequacy rather than specific local or regional needs.

[10] Approximately 50 MW of remaining capacity is available at Murray TS (T13/T14) according to the IRRP reference planning forecast.

[11] For existing station DG connection availability, consider Hydro One's capacity evaluation tool for generation applicants.

7.2.2 Non-Wires Options for the Asset Replacement Needs

Outcomes of screening non-wires options for the Crowland TS asset replacement need were aligned with the screening outcomes for the Crowland TS incremental station capacity need (i.e., the capacity need that persists even if the station is replaced like-for-like).

7.2.3 Non-Wires Options for the Load Security Needs

Due to the nature of planning criteria outlined in ORTAC 7.2, non-wires options such as CDM and DG cannot be applied to load security needs because they usually do not enable uninterruptable power supply to customers in the event of transmission contingencies. While voluntary load loss such as DR could help address the intent of load security planning criteria, it is an option type currently procured through the provincial capacity auction. This implementation mechanism is not the optimal approach, as its current design does not include the monitoring of local adequacy nor permit immediate responses after specific local contingencies. For these reasons, non-wires options are typically screened out for load security needs unless there are exceptional circumstances identified during the IRRP development.

7.3 Options and Recommendations for Meeting the Beamsville TS, Niagara West MTS, and Vineland DS Needs

7.3.1 Transmission Options

Due to the geographic proximity of Beamsville TS, Niagara West MTS, and Vineland DS, integrated transmission options were developed to address the station capacity needs in a coordinated manner. Three options for additional station capacity for the area were considered:

1. The replacement of existing Niagara West MTS with new 2 x 75/125 MVA transformers;
2. The expansion of Niagara West MTS with two new 67 MVA transformer units; or
3. A new, separate 230 kV station supplied from Q23BM and Q25BM.

Option 1 was ruled out, given that there was no indication of asset replacement needs at the existing Niagara West MTS (resulting in stranded asset costs), plus the risk of reduced reliability expected when implementing the replacement. Option 2 was estimated to cost as little as $17M and require three years from the commitment date, whereas Option 3 was estimated to cost up to $40M (depending on the size of the transformers and implementer) and would take three to four years.[12]

Given the immediate need at Beamsville TS, the Technical Working Group also considered load transfer capabilities in the near-term. Beamsville TS and Niagara West MTS both supply Grimsby Power, NPEI, and Hydro One Distribution, while Vineland DS supplies only NPEI. At the time of this IRRP, Grimsby Power estimated the ability to transfer approximately 7 MW of NPEI's forecast load at Beamsville TS to Niagara West MTS. Beyond this amount, the Niagara West MTS station capacity need would arise sooner than already forecast. There is also some remaining capacity (approximately 4 MW) expected at Vineland DS.

[12] All cost estimates, unless otherwise specified, are net present values based on a levelized cash flow analysis rather than capital costs – see Appendix F. In this case, a capital cost estimate of $19M (+/-15%) was provided for Option 2 and $25M - $40M for Option 3.

7.3.2 Non-Wires Options

As explained in Section 7.2.1.1, non-wires options were screened in for additional evaluation for the Beamsville TS and Vineland DS needs.

For Beamsville TS, a number of measures were assessed – such as combinations of incremental targeted CDM with battery storage or gas generation.[13] The most cost-effective non-wires solution portfolio included incremental CDM (approximately 6 MW of additional savings by 2041), plus battery storage assumed to be installed in two phases (2025 and 2038) to match the need profile.[14] For Vineland DS, the incremental CDM potential was also calculated: approximately 2 MW of additional demand savings by 2041.

The net present value ("NPV") of the portfolio of non-wires options for both Beamsville TS and Vineland TS was calculated to be $30M - $57M. The lower cost assumed that the incremental CDM is already system cost-effective based on provincial resource adequacy, whereas the higher cost assumed that the demand savings targeted to these stations would be incremental to the provincial CDM framework. More details on the CDM potential methodology and results are provided in Appendix E.

7.3.3 Recommendation

During the development of the IRRP, the forecasts at Beamsville TS and Niagara West MTS were updated by the impacted LDCs as growth trended higher and new potential customers were identified. By the conclusion of the IRRP, this reinforced the preference for the integrated wires options due to their cost-effectiveness and ability to address the capacity needs at all three stations.

The original scope of the non-wires options that were developed only addressed the Beamsville TS and Vineland DS needs, but were collectively $13M – $40M more expensive than the least expensive wires option. The increased forecast for Niagara West MTS did not impact the wires option of a new 230 kV station in the area – it only increased its cost-effectiveness. Another portfolio of non-wires options sized for Niagara West MTS' final reference forecast capacity need would have increased the non-wires costs further. Reallocating the load forecast on the 115 kV stations to 230 kV supply also helps alleviate the broader Niagara 115 kV sub-system capacity need.

Therefore, due to the cost-effectiveness and ability to meet the multiple needs, the Technical Working Group recommends near-term load transfers to offload Beamsville TS, plus a new 230 kV station supplied from Q23BM and Q25BM. This could be accomplished by expanding the existing Niagara West MTS. The station should be in-service as soon as possible and accommodate at least 57 MW of pre-contingency load in the area by 2041.

It is recommended that after the IRRP, the impacted LDCs coordinate the magnitude and timing of load transfers between the three stations to manage and monitor the Beamsville TS capacity need until the new station is in-service. Moreover, the LDCs and Hydro One should coordinate during the RIP to establish the lead implementer of the new station. Timing, siting, and size of the new

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[13] Based on the unserved energy profile forecast at Beamsville TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[14] This included an 18 MW, 144 MWh battery storage facility. The Beamsville TS forecast was updated and increased near the end of the IRRP forecast; cost range estimate would only increase with larger battery storage.

transformers should be factored into the decision – in addition to a comprehensive economic comparison that accounts for both the cost of the transformer station and the distribution-level costs that could incur if the station is sited farther west and away from the service territories that are expected to grow.

7.4 Options and Recommendations for Meeting the Crowland TS, Load Security, and Niagara 115 kV Sub-System Needs

The Crowland station capacity and asset replacement needs, as well as the A6C/A7C load security and Niagara 115 kV sub-system capacity needs, share common transmission elements and impact each other. As such, both wires and non-wires options were developed to address these four needs in an integrated fashion.

7.4.1 Transmission Options

Two sets of transmission options were identified – one that largely involves the continued buildout of the 115 kV system in the Niagara Region, and another that expands the 230 kV supply.

Option Set 1 includes:

- New 115 kV station in Welland, supplied by the existing A6C/A7C circuits (to address the Crowland TS capacity need);
- New 230 kV Allanburg bus (to improve supply to the 115 kV sub-system and mitigate the A6C/A7C load security need); and
- Re-building of 115 kV Crowland TS like-for-like (to address the asset replacement need).

Option Set 2 includes:

- Replacement of sections of 115 kV D3A/A3C circuits with approximately 18 km of new 230 kV double-circuit supply lines tapping off Q24HM and Q29HM; and
- The replacement of Crowland TS with a 230 kV station (to address its asset replacement and capacity needs, offload the Niagara 115 kV sub-system, and mitigate the A6C/A7C load security need).

In terms of preliminary capital costs, Option Set 1 was estimated to be approximately $253M - $353M[15] in total, whereas Option Set 2 may cost $128M.[16] Option Set 1 will require a minimum of three years; Option Set 2 will need six years.

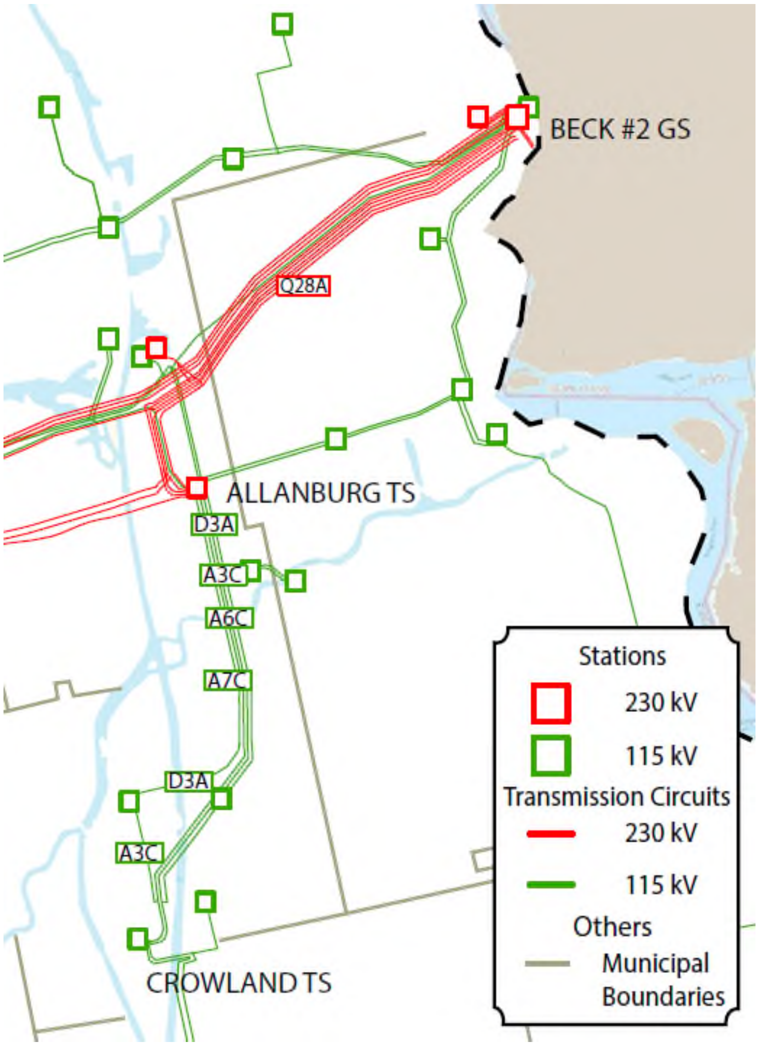
[15] The high end of the cost estimate range for Option Set 1 includes the potential for new 115 kV circuits and other reinforcements if the existing A6C/A7C circuits cannot accommodate the new 115 kV station in Welland.

[16] Capital cost estimates provided by Hydro One during the IRRP were prepared based on preliminary information and intended to provide a ballpark figure to be used strictly for initial options comparison. No engineering or field work was completed as part of the development of these cost allowances and as such, these cost allowances provide no cost guarantee or accuracy range. Costs allocations were derived from previous historical costs/unit costs and were to be used strictly for options comparison; Hydro One may refine and update cost estimates as part of the RIP.

To accommodate the planning forecast, the uprating of an existing 230 kV circuit, Q28A, is also required in addition to either Option Set. The cost and feasibility of this reinforcement is currently being assessed by Hydro One and is estimated to require until at least 2024 to be in-service.

The components of these Option Sets are identified conceptually on the map of Niagara Region's existing transmission system in Figure 22.

Figure 22 | Impacted Areas by the Transmission Options



Under some of the contingencies and conditions expected to limit the 115 kV sub-system LMC, operational measures such as load rejection are permissible according to ORTAC. Therefore, the benefit of a new load rejection scheme was also factored in when assessing the supply capability with each of the wires options described above. It was assumed that this scheme, developed and implemented by Hydro One for the Niagara 115 kV sub-system, could be installed in 2024 or later.[17]

[17] The ultimate in-service date will depend on the complexity of the scheme's design and NPCC approval timelines.

7.4.2 Non-Wires Options

As explained in Section 7.2.1.2 and 7.2.1.4, non-wires options were screened in for additional evaluation for the Crowland TS and 115 kV sub-system supply needs.

For the Crowland TS capacity need alone, incremental targeted CDM, battery storage, and gas generation were all considered either as standalone or integrated options.[18] The most cost-effective non-wires solution portfolio for the Crowland capacity need included incremental CDM (approximately 10 MW of additional savings by 2041), plus a 10 MW/40 MWh battery storage facility installed in two phases (2025 and 2038) to match the need profile. The NPV of this portfolio was calculated to be in the range of $17M - $53M. Similar to what was described for the Beamsville TS non-wires options, this cost range is attributed to the provincial CDM assumptions.[19]

As the Niagara IRRP progressed and the interplay between the Crowland TS needs and the broader Niagara 115 kV supply capability became clearer, a non-wires option was also considered at a high level. An all-generation, 240 MW alternative was sized to compare to the lowest cost transmission option set; 240 MW is the expected increase in the 115 kV sub-system supply capability enabled by Option Set 2 described previously. However, this non-wires option is not a feasible solution due to various factors. While an all-generation option was identified to compare to the wires option on a MW basis, there are significant challenges to implementing and operating a resource to address the multiple, layered, and local needs. For instance, for 240 MW of generation to address both the Crowland TS capacity and replacement needs, as well as the broader 115 kV supply needs, a portion of the generation must be sited on the distribution system to supply customers currently served by Crowland TS and the remaining must be targeted to the region's 115 kV system. There may also be thermal or short circuit limitations to connecting this amount of generation on the distribution system. Moreover, as described in Section 7.2.3, generation is typically not considered a feasible option to solve load security needs.

7.4.3 Recommendation

When comparing the two wires option sets, Option Set 2 is preferred for a number of reasons. It is the more cost-effective option, evaluated at more than $100M less expensive than Option Set 1 (based on capital cost estimates), even though both offer similar 115 kV sub-system supply capability and are sufficient according to the reference planning forecast. Qualitatively, by expanding the 230 kV transmission system, Option Set 2 also offers long-term flexibility to accommodate more load growth in the southern portion of the Niagara Region – particularly along the industrial and commercial hub around the Welland Canal. Option Set 1 provides limited growth options in the area in comparison to Option Set 2, without extensive station expansion at Allanburg TS. Meanwhile, converting the existing 115 kV Crowland TS to 230 kV in Option Set 2 allows the other 115 kV stations in the Niagara Region to accommodate new growth and maximizes the use of existing infrastructure with the available capacity normally utilized by the 115 kV Crowland TS. Triggering the

[18] Based on the unserved energy profile forecast at Crowland TS, the gas generator option was assumed to be a simple cycle gas turbine facility.

[19] Another sensitivity was conducted for the battery storage sizing, resulting in a higher cost range of $25M - $61M. See Appendix D.3 for more details.

reconfiguration is also a time-sensitive opportunity, since Crowland TS is expected to require asset replacement in the near term.[20]

Long-term flexibility can also be considered by comparing the options and their ability to accommodate the high IRRP forecast scenario. According to the reference forecast, approximately 200 MW of extra 115 kV supply capability is required by 2041. As shown in Section 6.3, the high scenario increased this requirement to 340 MW. Both Option Sets 1 and 2 enable the increased capability required for the reference forecast, and neither Option Set precludes a further wires or non-wires option in the long-term. These future actions can include new generation resources or additional 230/115 kV auto-transformation. In contrast, a non-wires option sized precisely to meet the reference need would have less flexibility to accommodate growth that exceeds today's expectations.

Regardless, none of the non-wires options described in Section 7.4.2 can sufficiently address the multiple needs at once. Wires Option Set 2 would cost-effectively resolve the Crowland capacity and replacement needs, the A6C/A7C security issue, and enable other load growth on the 115 kV sub-system. For these reasons, the Technical Working Group recommends the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM/Q29HM, as well as the uprating of Q28A. A new load rejection scheme should also be developed to manage the Niagara 115 kV sub-system need. The load forecast should be monitored between regional planning cycles, and there are benefits to targeting incremental CDM to the 115 kV sub-system in order to manage load growth beyond the reference scenario. The technical feasibility and costs of the wires recommendations should be further analyzed in the RIP; the IESO will continue to participate in the RIP Working Group to provide advice and input on this matter.

7.5 Summary of Recommended Actions and Next Steps

The Technical Working Group recommends the actions summarized in Table 5 to meet identified needs in the Niagara IRRP.

Table 5 | Summary of Needs and Recommended Actions

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Coordinate load transfers to offload Beamsville TS to Niagara West MTS in the near-term	• 2023

[20] All final cost estimates have accounted for the asset replacement value for Crowland TS.

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity • Niagara 115 kV sub-system supply capacity	• Grimsby Power • NPEI • Hydro One Distribution • Hydro One Transmission	• Initiate development for a new 230 kV station supplied from Q23BM and Q25BM, or an expansion of Niagara West MTS	• 2026-2027
• Beamsville TS, Niagara West MTS, and Vineland DS station capacity	• Grimsby Power • NPEI • Hydro One Distribution	• Monitor load growth between regional planning cycles	• Ongoing
• Beamsville TS and Vineland DS station capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to Beamsville TS and Vineland DS	• Ongoing
• Crowland TS station capacity and asset replacement • A6C/A7C load security • Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Initiate development for the replacement of Crowland TS with a new 230 kV station, supplied by new 230 kV double-circuit lines from Q24HM and Q29HM	• 2028
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Develop and implement a new 115 kV sub-system load rejection scheme	• 2024
• Niagara 115 kV sub-system supply capacity	• Hydro One Transmission	• Uprate Q28A	• 2024
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Monitor load growth between regional planning cycles	• Ongoing

Need(s)	Lead Responsibility	Technical Working Group Recommendation	Expected In-Service Date
• Niagara 115 kV sub-system supply capacity	• Technical Working Group	• Investigate opportunities to target incremental CDM to the 115 kV sub-system	• Ongoing
• Murray TS (T11/T12) station capacity	• NPEI • Hydro One Transmission	• Transfer load in excess of the station limit to Murray TS T13/T14	• 2023
• Carlton TS station capacity	• Alectra	• Monitor load growth between regional planning cycles • Transfer load in excess of the station limit to Bunting TS	• 2028
• Kalar MTS station capacity	• NPEI	• Monitor load growth between regional planning cycles and consider future opportunities for incremental CDM	• 2030

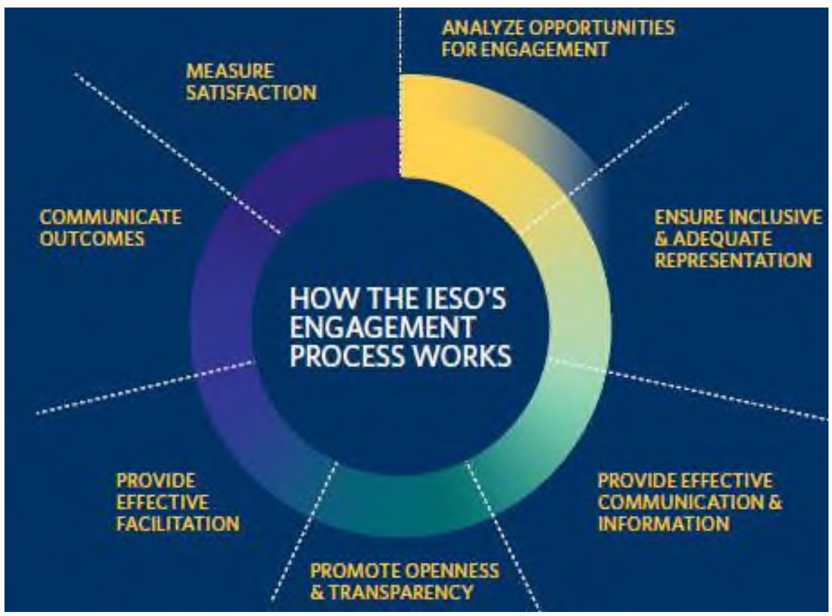
8. Community and Stakeholder Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the Niagara IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP. The IESO uses these principles to ensure inclusiveness, sincerity, respect, and fairness in its engagements, striving to build trusting relationships as a result.

Figure 23 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for Niagara Region

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope of the IRRP and are adequately informed about the background and issues in order to provide meaningful input on the development of the IRRP for the region.

Creating the engagement plan for this IRRP involved:

- Targeted discussions to help inform the engagement approach for this planning cycle;
- Communications and other engagement tactics to enable a broad participation, using multiple channels to reach audiences; and

- Identifying specific stakeholders and communities who may have a direct impact in this initiative and that should be targeted for further one-on-one consultation, based on identified and specific needs in the region.

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process;
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin;
- Public webinars; and
- Targeted one-on-one outreach with specific communities and stakeholders to ensure that their identified needs are addressed (see Section 8.4).

8.3 Engage Early and Often

The IESO held preliminary discussions to help inform the engagement approach for this second round of planning, and to establish new relationships and dialogue in this region where there has been no active engagement previously. This started with the Scoping Assessment Outcome Report for the Niagara Region. An invitation was sent to targeted municipalities, Indigenous communities, and those with an identified interest in regional issues, to announce the commencement of a new planning cycle and invite interested parties to provide input on the Niagara Region Scoping Assessment Report finalization. A public webinar was held in August 2021 to provide an overview of the regional electricity planning process and seek input on the high-level needs identified and proposed approach. The final Scoping Assessment was posted later in August 2021, identifying the need for a coordinated regional planning approach and an IRRP.

Following finalizing the Scoping Assessment, targeted outreach then began with municipalities in the region to inform early discussions for development of the IRRP, including the IESO's approach to engagement. The launch of a broader engagement initiative followed, with an invitation to IESO subscribers of the Niagara Region to ensure that all interested parties were made aware of this opportunity for input. Three public webinars were held at major stages during the IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components of the plan. These webinars were attended by a cross-representation of community representatives, businesses, and other stakeholders, and written feedback was collected over a 21-day comment period after each webinar.

The three stages of engagement at which input was invited:

1. The draft engagement plan, electricity demand forecast, and early identified needs – to set the foundation of this planning work.
2. The defined electricity needs for the region and high-level screening of potential options to meet the identified needs.
3. The analysis of options and draft IRRP recommendations.

Comments received during this engagement were primarily focused on:

- Ensuring key areas of growth in specific pockets in the Niagara Region (including the City of Niagara Falls and Town of Fort Erie), have been considered and accounted for in the IRRP work;
- Ensuring there are procedures to alter the implementation of plan recommendations should changes occur in the region; and
- Keeping lines of communication following the plan completion to share information and updates.

Feedback received during the written comment periods for these webinars helped to guide further discussions throughout the development of this IRRP, as well as add due consideration to the final recommendations.

All interested parties were kept informed throughout this engagement initiative via email to Niagara Region subscribers, municipalities, and Indigenous and Métis communities.

Based on the discussions through this engagement initiative, a key priority was to ensure the IRRP and recommended actions aligned with strong forecast growth and development both within specific municipalities and the region more broadly (e.g. future urban expansion and employment areas as outlined in the updated Niagara Region Official Plan). This insight has been valuable to the IESO – it supported an understanding of local growth and an accurate electricity demand forecast, the determination of needs, and the recommendation of solutions to ensure adequate and reliable long-term supply. To that end, ongoing discussions will continue through the IESO's Southwest Regional Electricity Network to keep interested parties engaged in a two-way dialogue on local developments, priorities, and initiatives to prepare for the next planning cycle.

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's Niagara IRRP engagement webpage.

8.4 Bringing Municipalities to the Table

The IESO held meetings with municipalities to seek input on their planning and to ensure that key local information about growth and development and energy-related initiatives were taken into consideration in the development of this IRRP. At major milestones in the IRRP process, meetings were held with the upper- and lower-tier municipalities in the region to discuss key issues of concern, including forecast regional electricity needs, options for meeting the region's future needs, and broader community engagement. These meetings helped to inform the municipal/community electricity needs and priorities, establish new relationships, and provided opportunities for ongoing dialogue beyond this IRRP process.

Through these discussions valuable feedback was received around strong anticipated growth in major growth centres in the region:

- Strong population growth across the Niagara Region based on 2051 growth projections and in some areas above and beyond the regional forecast (i.e. even higher growth expected in the City of Welland);
- Notable growth in the Town of Lincoln (greenhouses, Secondary Plan areas, potential GO Transit development), along the QEW corridor in Grimsby, and in Thorold;

- Strong economic development around the Welland Canal (e.g. Thorold Multimodal Hub "Niagara Ports");
- Key areas of growth in the City of Niagara Falls within intensification nodes and corridors, projects around the GO Transit Station and the new Niagara South Hospital, wastewater treatment plant, and residential new construction;
- Industrial, commercial, institutional, and residential development in the Town of Fort Erie and Secondary Plan areas; and
- Potential urban boundary expansion in the region totaling 130 hectares of residential and 150 hectares of employment lands.

8.5 Engaging with Indigenous Communities

To raise awareness about the regional planning activities underway and invite participation in the engagement process, regular outreach was made to Indigenous communities within the Niagara Region throughout the development of the plan. This includes the communities of the Mississaugas of the New Credit, Oneida Nation of the Thames and Six Nations of the Grand River (Six Nations Elected Council and Haudenosaunee Confederacy Chiefs Council) and Métis Nation of Ontario Niagara Region Métis Council.

The IESO remains committed to an ongoing, effective dialogue with communities to help shape long-term planning in regions all across Ontario.

9. Conclusion

The Niagara IRRP identifies electricity needs in the region over the 20-year period from 2022 to 2041, recommends a plan to address immediate and near-term needs, and lays out actions to monitor long-term needs. The IESO will continue to participate in the Technical Working Group during the next phase of regional planning, the RIP, to provide input and ensure a coordinated approach.

In the near term, the IRRP recommends load transfers off Beamsville TS and a new or expanded 230 kV station supplied by Q23BM and Q25BM. The IRRP also recommends the implementation of control actions on the Niagara 115 kV sub-system to manage overloads during outage conditions, plus the replacement of Crowland TS with a new 230 kV station supplied by new 230 kV lines from Q24HM and Q29HM. Q28A should be uprated, and a portion of the load at Murray TS (T11/T12) should be transferred to Murray TS (T13/T14). Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group.

In the long term, the IRRP recommends that the Technical Working Group monitor growth in the Niagara 115 kV sub-system, Carlton TS, and Kalar MTS to determine if or when further reinforcements will be needed. This includes monitoring any future community energy planning or electrification trends. Additionally, there are benefits to investigating opportunities to target incremental CDM to the region – particularly to the Beamsville TS/Vineland DS/Niagara West MTS areas and 115 kV sub-system in the near-term, and Kalar MTS in the long-term.

The Technical Working Group will meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the Ontario Energy Board.

Appendix 5-C: Customer Engagement Survey Workbook

Appendix 5-C – Customer Engagement Survey Workbook

Welland Hydro wants to hear from you!

Dear valued customer of Welland Hydro-Electric System Corp ("Welland Hydro"),

At Welland Hydro, we are committed to understanding and meeting the evolving needs of our customers. To achieve this, we are embarking on a journey to engage with you, our customers, regarding the current and future state of our electrical distribution system. Your insights will play a crucial role in shaping our Distribution System Plan ("Plan") for the next five years. The draft Plan outlines our proposed investments in equipment and infrastructure, the range of services we offer, and the rates you pay.

Welland Hydro needs your input on its draft Plan – your choices will help shape the service you receive and the price you pay. To help you better understand Welland Hydro's business, we invite you to participate in our online customer engagement survey. This survey is designed to give you enough background information about the decisions under consideration, enabling you to offer an informed opinion.

Your individual responses will be kept confidential. Constant Contact, a trusted marketing service platform, will be utilized to gather your feedback via the online survey. Constant Contact will combine your responses with others to provide an overall report to Welland Hydro.

As a token of our appreciation for your participation, customers who complete Welland Hydro's online survey will be invited to enter a draw to win one (1) $500 cash prize.

To participate in Welland Hydro's customer engagement survey, please click here or on the URL below or copy and past it into the address bar of your browser:

Survey Link

Thank you for taking the time to share your valuable feedback with us.

Sincerely,

Welland Hydro-Electric System Corp.

Welland Hydro-Electric System Corp. – Customer Engagement Survey

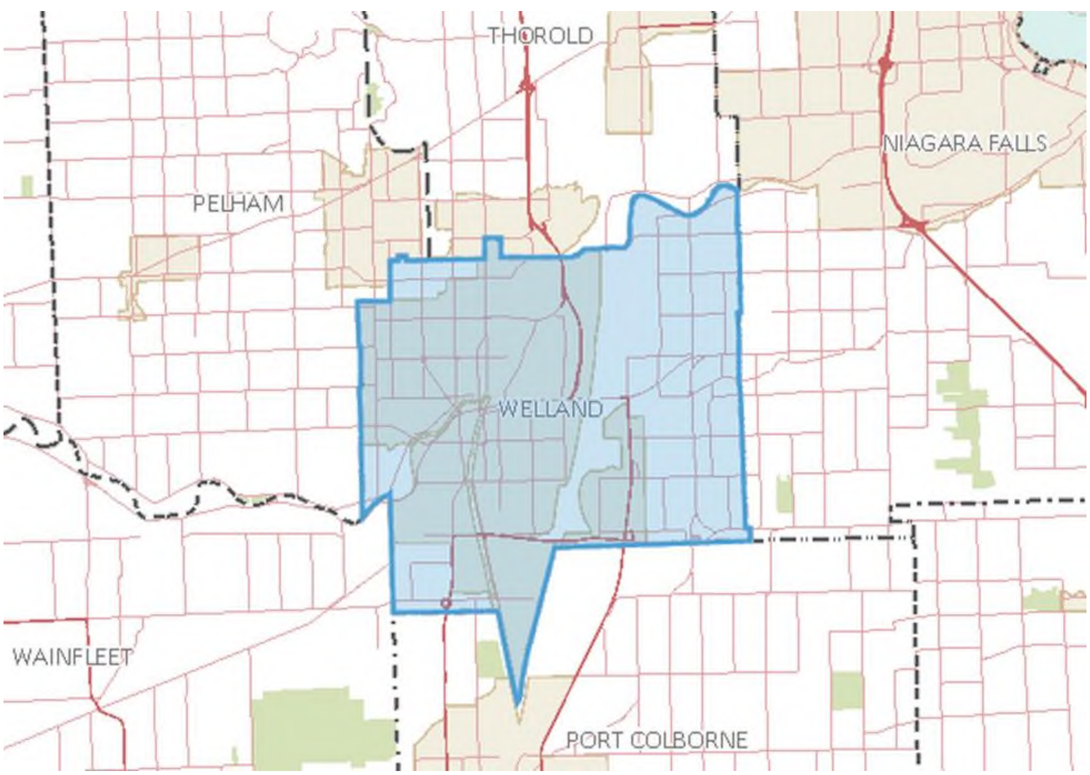
Survey Conducted: May 15th to May 31st, 2024.

1) **What type of electricity customer are you?**
   - ☐ Residential
   - ☐ Small Business (described on your bill as account type GS < 50)
   - ☐ Commercial/Industrial (described on your bill as account type GS > 50)
   - ☐ I'm not a Welland Hydro customer

About Welland Hydro Electric System Corp.

Welland Hydro-Electric System Corp. ("Welland Hydro") distributes electricity to approximately 26,000 customers, including over 23,750 residential customers, within the City of Welland. Welland Hydro-Electric System Corp. is a wholly owned subsidiary of Welland Hydro-Electric Holding Corp., owned by the City of Welland.

Welland Hydro is currently preparing its 2025 Cost of Service Rate Application which will be submitted to the Ontario Energy Board (OEB). As part of our Distribution System Planning process, we would like your input and feedback on our planned investments for the next five years. Welland Hydro's Service Area is as follows:



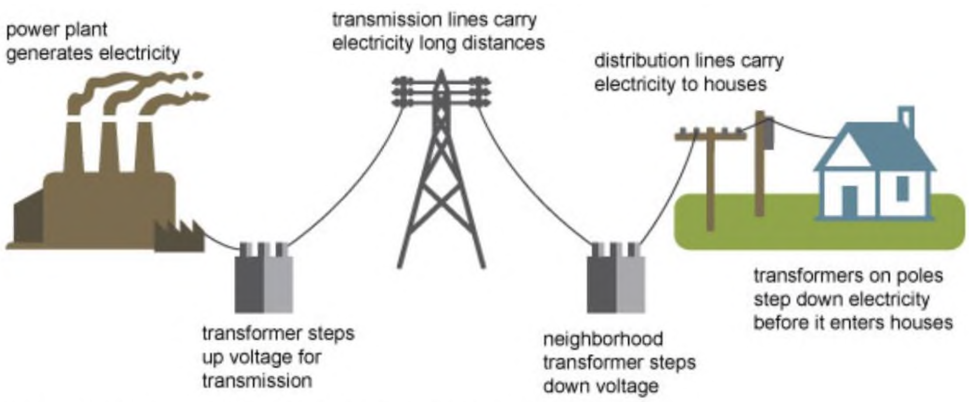
Welland Hydro's Role in Providing You with Electricity

There are three main parts of the system used to supply electricity to your home or business:

Generation: Electricity is produced at nuclear or natural gas plants and from renewable sources including hydro-electric, solar, and wind.

Transmission: Generated electricity moves from generation facilities to local electrical distribution companies over high voltage power lines.

Distribution: Local electrical distribution companies like Welland Hydro, deliver power to you.

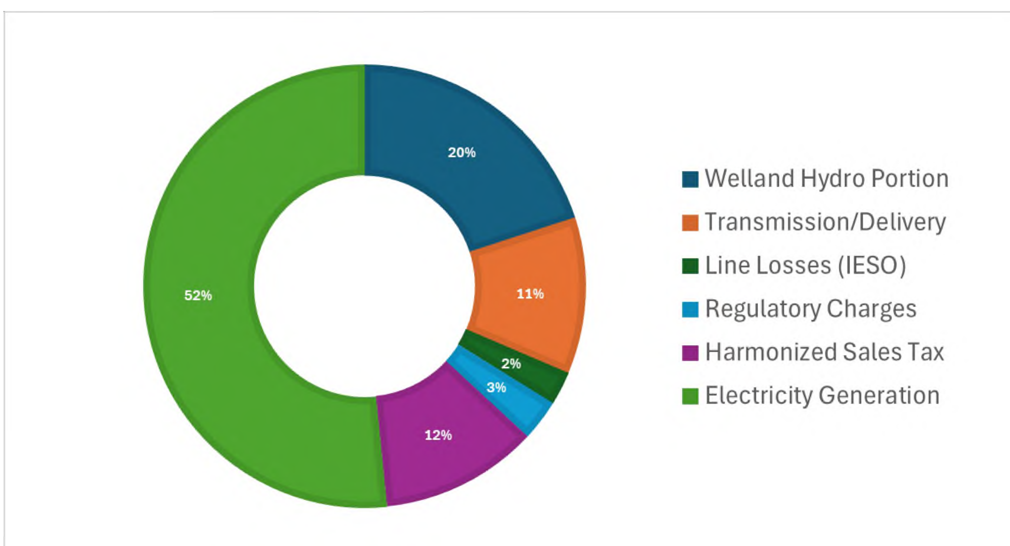


Source: Adapted from National Energy Education Development Project (public domain)

Distribution as a Component of Your Electricity Bill

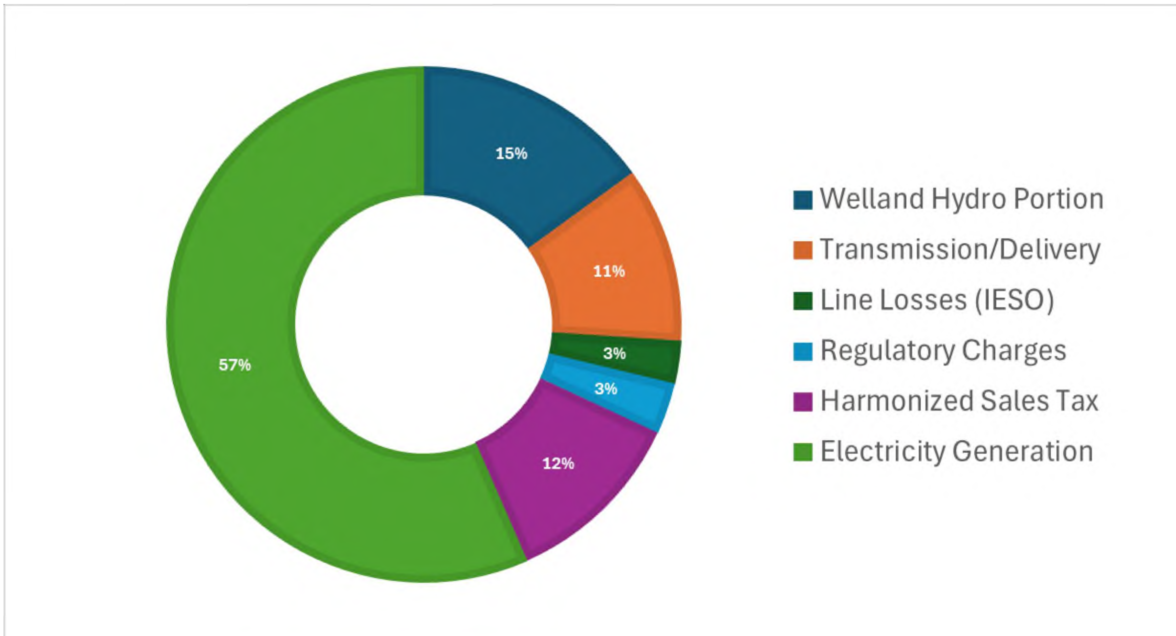
Residential Customer

For a residential customer, Welland Hydro's portion of the electricity bill is $32.35 (as of May 1, 2024). For a typical residential customer, consuming 750kWh, this amounts to 20% of the total bill. The remaining 80% of the bill is passed onto transmission companies, power generation companies, regulatory agencies, and government. The following chart depicts the typical monthly bill components:



Small Business Customer

For a small business customer consuming 2,000 kWh per month, Welland Hydro's portion of the electricity bill is $59.14 (as of May 1, 2024). This amounts to approximately 15% of the total bill. The remaining 85% of the bill is passed onto transmission companies, power generation companies, regulatory agencies, and government. The following chart depicts the typical monthly bill components:



2) **Before participating in this survey, how familiar were you with the amount of your electricity bill going to Welland Hydro?**

- ☐ Very Familiar
- ☐ Somewhat Familiar
- ☐ Not Familiar at All
- ☐ Don't Know

3) **Overall, how satisfied are you with the service Welland Hydro provides?**

- ☐ Extremely Satisfied
- ☐ Very Satisfied
- ☐ Somewhat Satisfied
- ☐ Not Very Satisfied
- ☐ Not Satisfied at All
- ☐ Don't Know

4) Please indicate which of the following aspects pertaining to the delivery of electricity is most important to you (check all that apply):

- ☐ Safe for Customers?
- ☐ Reliable?
- ☐ At an affordable price?

5) In the next five years, how likely is it that you would use your electrical service for:

a) Charging an electric vehicle?

- ☐ I'm already charging an electric vehicle at my home/business
- ☐ Very Likely
- ☐ Likely
- ☐ Somewhat Likely
- ☐ Not Very Likely
- ☐ Don't Know

b) Connecting solar panels to offset your consumption from the distribution grid?

- ☐ I already have solar panels connected to my electrical system
- ☐ Very Likely
- ☐ Likely
- ☐ Somewhat Likely
- ☐ Not Very Likely
- ☐ Don't Know

c) Connecting a battery storage system to help meet your electricity needs?

- ☐ I already have a battery storage system at my home/business
- ☐ Very Likely
- ☐ Likely
- ☐ Somewhat Likely
- ☐ Not Very Likely
- ☐ Don't Know

6) As you think about your electricity consumption over the next five years, which statement best describes your needs:

- ☐ My electricity usage will increase significantly
- ☐ My electricity usage will increase somewhat
- ☐ My electricity usage will remain about the same
- ☐ My electricity usage will decrease somewhat
- ☐ My electricity usage will decrease significantly
- ☐ Don't Know

7) How likely is it that your primary heating source will be fueled by electricity in the next five years?

- ☐ My primary heating source is already fueled by electricity
- ☐ Very Likely
- ☐ Likely
- ☐ Somewhat Likely
- ☐ Not Very Likely
- ☐ Don't Know

8) As it relates to climate change, how important is it for Welland Hydro to prepare for extreme weather events that may occur in the future and minimize power outages to the extent possible?

- ☐ Extremely Important
- ☐ Very Important
- ☐ Somewhat Important
- ☐ Not Very Important
- ☐ Not Important at All
- ☐ Don't Know

9) **Welland Hydro has considered ways to improve the customer experience by implementing web and/or application based technology enhancements. How important are (or would) each of the following be to you?**

   a) **Access to an online outage map?**

      - ☐ Important
      - ☐ Not Important

   b) **Improved outage communications via social media platforms such as Facebook and 'X'?**

      - ☐ Important
      - ☐ Not Important

   c) **Outage communications vis SMS (text message)?**

      - ☐ Important
      - ☐ Not Important

   d) **Improved live chat features to get immediate answers to inquiries?**

      - ☐ Important
      - ☐ Not Important

   e) **Real time monitoring of consumption to allow better control over electricity usage?**

      - ☐ Important
      - ☐ Not Important

10) **Welland Hydro's current hours of operation for customer service availability is 9am to 3:30pm on weekdays. Welland Hydro is considering expanding its hours of customer service availability from 8:30am to 4pm on weekdays, providing improved performance in its responsiveness to customer inquiries. If this could be achieved at a cost impact on a typical residential bill of $0.26 monthly, how important is this to you?**

    - ☐ Extremely Important
    - ☐ Very Important
    - ☐ Somewhat Important
    - ☐ Not Very Important
    - ☐ Not Important at All
    - ☐ Don't Know

11) **Welland Hydro provides online forms for opening a new account, transferring an account, and processing of service upgrades, among others. How likely are you to use online forms versus contacting Welland Hydro by phone for these matters?**

- ☐ Very Likely
- ☐ Likely
- ☐ Somewhat Likely
- ☐ Not Very Likely
- ☐ Don’t Know

Capital Investments

Welland Hydro’s planned capital investments for 2025 through 2029 are intended to sustain existing distribution assets such as poles and wires. Capital investments are also planned to improve system reliability while connecting new customers to the distribution system, as the City of Welland’s population continues to grow.

Capital investments are categorized into one of four classifications which are described below:

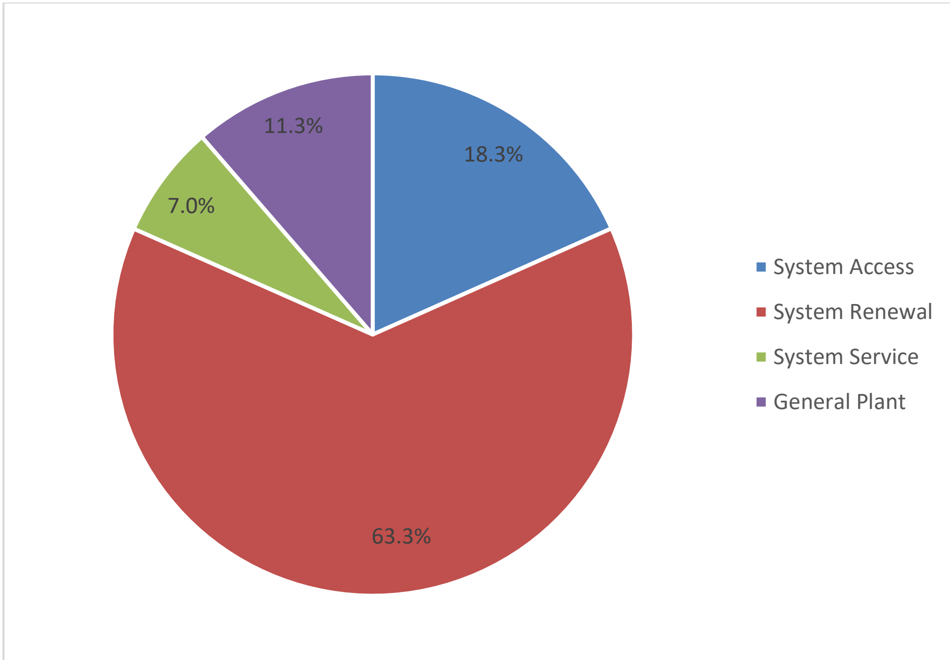
System Access ($3.8 million): System Access investments in the distribution system accommodate new connections or facilitate new infrastructure development. Investments in this category must occur annually as Welland Hydro is obligated to provide access to the distribution system and its electricity services. Projects include the connection of new residential subdivisions, connection of new commercial and industrial services, and the relocation of assets based on road infrastructure needs.

System Renewal ($13.1 million): These investments in the distribution system are generally to replace assets at end of life. Projects include the replacement of poles, overhead circuits, underground cables, transformers, and station assets.

System Service ($1.5 million): System Service based investments are aimed at improving system reliability and resiliency. Projects include distributed automation deployments and new distribution circuit interties.

General Plant ($2.3 million): These investments are required to support operation of the distribution system. Planned investments include large bucket trucks, light duty vehicles, IT / cybersecurity systems, and facility upgrades.

In these four categories, Welland Hydro has determined, through its asset management process, that $20.7 million of investment is required to meet its objectives from 2025 through 2029. The majority of planned investments are in the System Renewal category, accounting for 63% of planned capital expenditures:



A significant portion of Welland Hydro's five-year capital plan is not discretionary. For example, Welland Hydro is obligated to facilitate new connections to the electrical distribution system. Investments in the System Access category contain projects associated with the connection of new customers and Welland Hydro has little choice regarding the required expenditure and timing.

Planned investments in the System Renewal category target assets at end of life that require replacement. The following questions pertain to planned investments for specific project types in this category.

Overhead Line Rebuilds

The majority of Welland Hydro's distribution system consists of overhead lines. Approximately $7.3M of investment is planned to rebuild sections of the overhead system. This includes the replacement of approximately 550 poles, 120 transformers, and 24km of deficient conductor. For reference, Welland Hydro's recent Asset Condition assessment indicates that 591 poles are in "Very Poor" condition.

12) Given the details provided about planned overhead line rebuilds in the next five years, should Welland Hydro:

- ☐ Proceed with the current plan, replacing 550 poles in "Very Poor" condition.
- ☐ Proceed at an accelerated pace, replacing 750 poles, including poles in both "Very Poor", and "Poor" condition. For a residential customer, this would result in a bill increase of $0.04 per month annually ($0.48 more per year).
- ☐ Proceed at a slower pace, replacing only 300 poles in "Very Poor" condition. For a residential customer, this would result in a bill decrease of $0.03 per month annually ($0.36 less per year).

Underground System Replacements

Welland Hydro maintains approximately 160km of underground distribution systems. Approximately $5.1M of investment is planned to rebuild sections of the underground system. This includes the replacement of approximately 4km of deficient cable, 60 transformers, and 5 switching cubicles. For reference, Welland Hydro's recent Asset Condition assessment indicates that 3.7km of underground cable is in "Poor" or "Very Poor" condition, with 11km being over 40 years in service.

13) Given the details provided about planned underground system replacements in the next five years, should Welland Hydro:

- ☐ Proceed with the current plan, replacing 4km of cable and associated systems over 40 years in service.
- ☐ Proceed at an accelerated pace, replacing 6km of cable and associated systems over 40 years in service. For a residential consumer, this would result in a bill increase of $0.02 per month annually ($0.24 more per year).
- ☐ Proceed at a slower pace, replacing 3.2 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).

Grid Modernization Investments

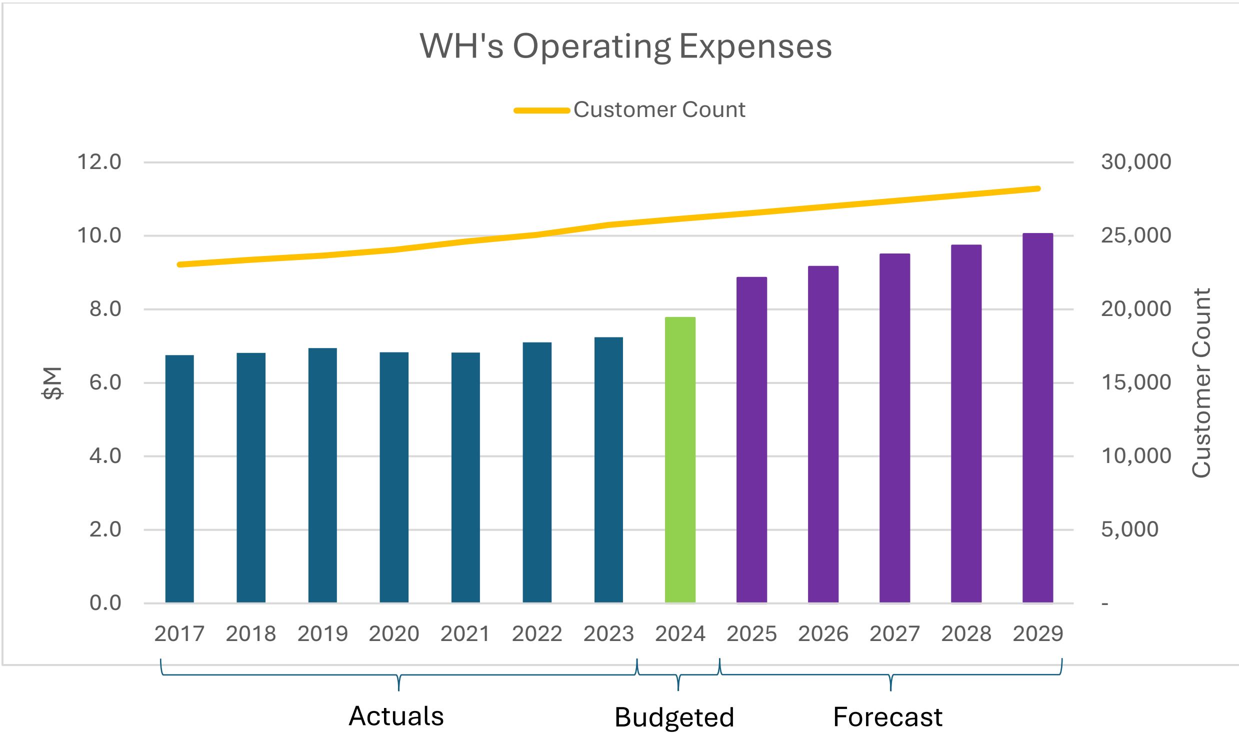
Welland Hydro maintains a fleet of 34 automated devices on its main distribution system. These devices are designed to detect system anomalies and operate to isolate faulted sections of circuit. Welland Hydro's system control staff leverages these devices to minimize the number of customers impacted by an outage and in many cases, mitigate the total duration of the event. The five-year investment plan includes $875K for the deployment of 10 additional automated devices to maintain or improve reliability as the distribution system expands to accommodate growth.

14) Based on the grid modernization investments planned for the next five years, should Welland Hydro:

- ☐ Proceed with the current plan, introducing two new automated devices per year.
- ☐ Proceed at an accelerated pace, introducing three new automated devices per year. For a residential consumer, this would result in a bill increase of $0.01 per month annually ($0.12 more per year).
- ☐ Proceed at a slower pace, introducing one new automated device per year. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).

Operating Expenses

Welland Hydro's operating budget covers recurring expenses associated with the operation and maintenance of the distribution system. This also covers the day-to-day administration of IT infrastructure, billing systems, and customer-service related expenses. The proposed plan for 2025-2029 includes approximately $47M for Welland Hydro's operating expenses. The following chart depicts Welland Hydro's historical and planned operating expenditures.



Inflation and customer growth are the two major factors driving WH's forecasted operating expenses. Welland Hydro's operating costs are benchmarked against other LDC's in Ontario. Welland Hydro has compared its performance to the other LDC's in the Niagara Region. The most recent benchmarking data available for 2022, shows that Welland Hydro ranks 1st in the Niagara Region for having the lowest total cost per Customer:

OEB CUSTOM SCORECARD REPORT (Reporting Year: 2022)	
Distributor	**Total Cost ($) per Customer**
Welland Hydro-Electric System Corp.	518
Grimsby Power Incorporated	660
Alectra Utilities Corporation	753
Niagara-on-the-Lake Hydro Inc.	804
Niagara Peninsula Energy Inc.	812
Canadian Niagara Power Inc.	968
Hydro One Networks Inc.	1,172

Source: Electricity Distributor Performance - Build a Custom Report (oeb.ca)

15) How appropriate do you think Welland Hydro's proposed operating budget is?

- ☐ Very Appropriate
- ☐ Somewhat Appropriate
- ☐ Not Very Appropriate
- ☐ Not at All Appropriate

- ☐ Don't Know

We thank you for your time and assistance with our investment decisions over the next five-year period. We have just a few more questions to help us understand a bit more about you as a Welland Hydro customer and your preferences.

16) What is the best way for Welland Hydro to communicate with you moving forward?

- ☐ Customer Service Representative
- ☐ Welland Hydro's Website
- ☐ E-Mail Notification
- ☐ Text Message
- ☐ Newspaper
- ☐ Radio
- ☐ Social Media
- ☐ Bill Insert
- ☐ Other, Please Specify ____

17) What type of information would you like to receive?

- ☐ Information on how to reduce my electricity consumption
- ☐ New programs that help you manage your electricity usage
- ☐ Electrical safety information
- ☐ Other, Please Specify ____

18) How long have you been a customer of Welland Hydro?

- ☐ Less than 2 years
- ☐ 2 – 5 years
- ☐ 6 – 10 years
- ☐ More than 10 years
- ☐ I'm not a Welland Hydro Customer

19) What is your approximate age?

- ☐ Under 20 years of age
- ☐ 20 - 29
- ☐ 30 - 39

- ☐ 40 - 49
- ☐ 50 - 59
- ☐ Over 60 years of age
- ☐ I'd prefer not to answer

20) How many individuals occupy your household (if applicable)?

- ☐ 1-2
- ☐ 3-4
- ☐ 5-6
- ☐ 7 or more
- ☐ I'd prefer not to answer

Appendix 5-D: Customer Engagement Survey Results

Constant Contact Survey Results

Campaign Name: Welland Hydro 2025 Cost of Service Survey

Survey Starts: 2494

Survey Submits: 988

Export Date: 05/31/2024 04:12 PM

MULTIPLE CHOICE

What type of electricity customer are you?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Residential		973	98%
Small Business (described on your bill as account type GS < 50)		11	1%
Commercial/Industrial (described on your bill as account type GS > 50)		2	0%
I'm not a Welland Hydro customer		2	0%
	Total Responses	988	100%

MULTIPLE CHOICE

Before participating in this survey, how familiar were you with the amount of your electricity bill going to Welland Hydro?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Very Familiar		195	19%
Somewhat Familiar		369	37%
Not Familiar at All		393	39%
Don't Know		31	3%
	Total Responses	988	100%

MULTIPLE CHOICE

Overall, how satisfied are you with the service Welland Hydro provides?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Extremely Satisfied		259	26%
Very Satisfied		518	52%
Somewhat Satisfied		187	18%
Not Very Satisfied		7	0%
Not Satisfied at All		3	0%
Don't Know		14	1%
	Total Responses	988	100%

CHECKBOXES

Please indicate which of the following aspects pertaining to the delivery of electricity is most important to you (check all that apply):

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Safe for Customers		507	51%
Reliable		744	75%
At an affordable price		797	80%
	Total Responses	988	100%

MULTIPLE CHOICE

a) Charging an electric vehicle?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
I'm already charging an electric vehicle at my home/business		27	2%
Very Likely		65	6%
Likely		54	5%
Somewhat Likely		132	13%
Not Very Likely		622	62%
Don't Know		88	8%
	Total Responses	988	100%

MULTIPLE CHOICE

b) Connecting solar panels to offset your consumption from the distribution grid?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
I already have solar panels connected to my electrical system		6	0%
Very Likely		36	3%
Likely		43	4%
Somewhat Likely		119	12%
Not Very Likely		667	67%
Don't Know		117	11%
	Total Responses	988	100%

MULTIPLE CHOICE

c) Connecting a battery storage system to help meet your electricity needs?

Answer Choice	0%	100%	Number of Responses	Responses Ratio
I already have a battery storage system at my home/business			6	0%
Very Likely			34	3%
Likely			40	4%
Somewhat Likely			104	10%
Not Very Likely			694	70%
Don’t Know			110	11%
		Total Responses	**988**	**100%**

MULTIPLE CHOICE

As you think about your electricity consumption over the next five years, which statement best describes your needs:

Answer Choice	0%	100%	Number of Responses	Responses Ratio
My electricity usage will increase significantly			19	1%
My electricity usage will increase somewhat			176	17%
My electricity usage will remain about the same			691	69%
My electricity usage will decrease somewhat			61	6%
My electricity usage will decrease significantly			8	0%
Don't know			33	3%
		Total Responses	**988**	**100%**

MULTIPLE CHOICE

How likely is it that your primary heating source will be fueled by electricity in the next five years?

Answer Choice	0%	100%	Number of Responses	Responses Ratio
My primary heating source is already fueled by electricity			96	9%
Very Likely			46	4%
Likely			76	7%
Somewhat Likely			78	7%
Not Very Likely			600	60%
Don’t Know			92	9%
		Total Responses	**988**	**100%**

MULTIPLE CHOICE

As it relates to climate change, how important is it for Welland Hydro to prepare for extreme weather events that may occur in the future and minimize power outages to the extent possible?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Extremely Important		387	39%
Very Important		391	39%
Somewhat Important		152	15%
Not Very Important		20	2%
Not Important at All		22	2%
Don't know		16	1%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

a) Access to an online outage map?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Important		825	83%
Not Important		163	16%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

b) Improved outage communications via social media platforms such as Facebook and ‘X’?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Important		606	61%
Not Important		382	38%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

c) Outage communications vis SMS (text message)?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Important		779	78%
Not Important		209	21%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

d) Improved live chat features to get immediate answers to inquiries?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Important		636	64%
Not Important		352	35%

		Total Responses	988	100%

MULTIPLE CHOICE

e) Real time monitoring of consumption to allow better control over electricity usage?

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Important			762	77%
Not Important			226	22%
		Total Responses	988	100%

MULTIPLE CHOICE

Welland Hydro’s current hours of operation for customer service availability is 9:00 am to 3:30 pm on weekdays. Welland Hydro is considering expanding its hours of customer service availability from 8:30 am to 4:00 pm on weekdays, providing improved performance in its responsiveness to customer inquiries. If this could be achieved at a cost impact on a typical residential bill of $0.26 monthly, how important is this to you?

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Extremely Important			85	8%
Very Important			92	9%
Somewhat Important			207	20%
Not Very Important			271	27%
Not Important at All			312	31%
Don't know			21	2%
		Total Responses	988	100%

MULTIPLE CHOICE

Welland Hydro provides online forms for opening a new account, transferring an account, and processing of service upgrades, among others. How likely are you to use online forms versus interacting directly with a Customer Service Representative for these matters?

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Very Likely			347	35%
Likely			247	25%
Somewhat Likely			206	20%
Not Very Likely			154	15%
Don’t Know			34	3%
		Total Responses	988	100%

MULTIPLE CHOICE

Given the details provided about planned overhead line rebuilds in the next five years, should Welland Hydro:

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Proceed with the current plan, replacing 550 poles in “Very Poor” condition.			352	35%
Proceed at an accelerated pace, replacing 750 poles, including poles in both “Very Poor”, and “Poor” condition. For a residential customer, this would result in a bill increase of $0.04 per month annually ($0.48 more per year).			560	56%
Proceed at a slower pace, replacing only 300 poles in “Very Poor” condition. For a residential customer, this would result in a bill decrease of $0.03 per month annually ($0.36 less per year).			76	7%
		Total Responses	**988**	**100%**

MULTIPLE CHOICE

Given the details provided about planned underground system replacements in the next five years, should Welland Hydro:

Answer Choice	0%	100%	Number of Responses	Responses Ratio
Proceed with the current plan, replacing 4 km of cable and associated systems over 40 years in service.			380	38%
Proceed at an accelerated pace, replacing 6 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill increase of $0.02 per month annually ($0.24 more per year).			532	53%
Proceed at a slower pace, replacing 3.2 km of cable and associated systems over 40 years in service. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).			76	7%
		Total Responses	**988**	**100%**

MULTIPLE CHOICE

Based on the grid modernization investments planned for the next five years, should Welland Hydro:

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Proceed with the current plan, introducing two new automated devices per year.		390	39%
Proceed at an accelerated pace, introducing three new automated devices per year. For a residential customer, this would result in a bill increase of $0.01 per month annually ($0.12 more per year).		507	51%
Proceed at a slower pace, introducing one new automated device per year. For a residential customer, this would result in a bill decrease of $0.01 per month annually ($0.12 less per year).		91	9%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

How appropriate do you think Welland Hydro’s proposed operating budget is?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Very Appropriate		318	32%
Somewhat Appropriate		449	45%
Not Very Appropriate		46	4%
Not at All Appropriate		10	1%
Don’t Know		165	16%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

What is the best way for Welland Hydro to communicate with you moving forward?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Customer Service Representative		39	3%
Welland Hydro’s Website		56	5%
E-Mail Notification		736	74%
Text Message		96	9%
Newspaper		4	0%
Radio		1	0%
Social Media		12	1%
Bill Insert		43	4%
Other		1	0%
	Total Responses	**988**	**100%**

CHECKBOXES

What type of information would you like to receive (check all that apply)?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Information on how to reduce my electricity consumption		696	70%
New programs that help you manage your electricity usage		712	72%
Electrical safety information		374	37%
Other		52	5%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

How long have you been a customer of Welland Hydro?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Less than 2 years		252	25%
2 – 5 years		174	17%
6 – 10 years		139	14%
More than 10 years		422	42%
I'm not a Welland Hydro Customer		1	0%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

What is your approximate age?

Answer Choice	0% 100%	Number of Responses	Responses Ratio
Under 20 years of age		1	0%
20 - 29		73	7%
30 - 39		166	16%
40 - 49		159	16%
50 - 59		183	18%
Over 60 years of age		384	38%
I'd prefer not to answer		22	2%
	Total Responses	**988**	**100%**

MULTIPLE CHOICE

How many individuals occupy your household (if applicable)?

Answer Choice	0%	100%	Number of Responses	Responses Ratio
1 - 2			568	57%
3 - 4			308	31%
5 - 6			73	7%
7 or more			14	1%
I'd prefer not to answer			25	2%
		Total Responses	**988**	**100%**

OPEN QUESTION

Email

970 Response(s)

Appendix 5-E: Regional Infrastructure Plan

NIAGARA

REGIONAL INFRASTRUCTURE PLAN

July 12, 2023

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Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

Niagara Technical Working Group

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 (TWG).

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.

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

EXECUTIVE SUMMARY

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 NIAGARA REGION.

The participants of the Niagara Region Regional Infrastructure Plan ("RIP") Technical Working Group ("TWG") included members from the following organizations:

- Alectra Utilities Corporation ("Alectra")
- Canadian Niagara Power Inc. ("CNP")
- Grimsby Power Inc. ("Grimsby Power")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Niagara-on-the-Lake Hydro Inc. ("NOTL")
- Niagara Peninsula Energy Inc. ("NPEI")
- Welland Hydro Electric System Corp. ("Welland Hydro")

This RIP is the final phase of the second cycle of the Niagara Region regional planning (RP) process and it follows the completion of the Niagara Region Integrated Regional Resource Plan ("IRRP") [1] in December 2022; and the Niagara Region Needs Assessment ("NA") [2] and Scoping Assessment ("SA") in May 2021 and August 2021, respectively. This RIP provides a consolidated summary of needs and recommended plans for the Niagara Region over a 10-year planning horizon (2023-2032) 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 covered and confirmed in future regional planning cycles.

The first cycle of Regional Planning process was completed in March 2017 with the publication of the Niagara Region RIP [3], which provided a description of needs and recommendations of preferred wires plans to address near-term needs. Since the previous planning cycle, the following projects have been completed:

- Decew Falls SS (2017) – Five (5) 115kV breakers were replaced with sulfur hexafluoride (SF_6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – The existing 40/53/67 MVA, 115/13.8 kV transformer T2 was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Some 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – The 28/37/47 MVA, 115/27.6 kV transformers T61 and T62 were replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

The recommended major infrastructure investments including assets replacements in the Niagara Region over the near and medium-term (2023-2032) period are given in Table 1 on the next page, along with their planned in-service date and budgetary estimate for planning purposes.

The Niagara Region 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;
- All the other identified needs/options are to be further reviewed by the TWG in the next regional planning cycle.

The next regional planning cycle for the Niagara Region must be triggered within five years, beginning with the Needs Assessment (“NA”) phase. It is expected that the next NA will be initiated in 2026. However, the next regional planning cycle can be started earlier if required to address any new emerging needs.

Table 0-1 Niagara Region - Recommended Plans over the 2023-2032 Study Period

No.	Investments	I/S Date	Cost[1]
A	**Increase Capacity**		
1	230 kV circuit Q28A – Uprate circuit between Beck 2 SS and Abitibi Jct.	TBD	$3M
2	Lincoln Area: Build new 230/27.6 kV, 50/83 MVA transformer station	2026	$45M
4	Crowland TS: Convert station to 230 kV with new 230/27.6 kV, 75/125 MVA transformer station and build a new 18 km of double circuit line from Abitibi Jct to Crowland TS	2027	$128M
5	Murray TS: Uprate T11/T12 75 MVA transformers with new 100MVA units	2027	$41M
6	Carlton TS: Transfer excess load to Bunting TS	2029	$5M
B	**Asset Replacement**		
1	Thorold TS: Replace Transformer T1	2024	$43M
2	Glendale TS: Replace Transformers T1 and T2	2027	$55M
3	Carlton TS: Replace LV Switchgear	2027	$55M
4	Bunting TS: Replace existing Transformers T1 and T2	2029	$45M
5	Murray TS: Replace Transformers T13 and T14	2031	$27M
6	Vansickle TS: Replace LV Switchgear	2032	$14M
7	Allanburg TS: Replace Transformer T3	2032	$20M
8	115kV Line D1A/D3A: Refurbish line section between Gibson Jct and Thorold TS	2024	$4M
9	115kV Line Q2AH: Refurbish line section between Rosedene Jct. and St. Anns Jct.	2025	$10M

[1] These costs are budgetary estimates for planning purposes only.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE NIAGARA REGION.

The report was prepared by Hydro One Networks Inc. (Transmission) ("Hydro One") on behalf of the Niagara Region 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:

- Alectra Utilities Corporation ("Alectra")
- Canadian Niagara Power Inc. ("CNP")
- Grimsby Power Inc. ("Grimsby Power")
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Independent Electricity System Operator ("IESO")
- Niagara-on-the-Lake Hydro Inc. ("NOTL")
- Niagara Peninsula Energy Inc. ("NPEI")
- Welland Hydro Electric System Corp. ("Welland Hydro")

The Niagara Region includes the Regional Municipality of Niagara as shown in Figure 1-1. It includes the Cities of Niagara Falls, Port Colborne, St. Catharines, Thorold and Welland, the Towns of Fort Erie, Grimsby, Lincoln, Niagara-on-the-Lake and Pelham and the Townships of Wainfleet and West Lincoln.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck Generating Station (GS) #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. Bulk supply is provided through the 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) connecting the Sir Adam Beck #2 Switching Station (SS) to stations in the Hamilton/Burlington area. The summer 2022 non-coincident peak load of the Region was about 977 MW.

Figure 1-1: Niagara Region Map

1.1 Scope and Objectives

This RIP report examines the needs in the Niagara Region. Its objectives are to:

- 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 needs;
- Provide the status of wires planning currently underway or completed for specific 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 reviews factors such as the load forecast, 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 (2023-2032) identified in previous planning phases (Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan);
- Identification of any new needs over the 2023-2032 period and wires plans to address these needs based on new and/or updated information;
- Consideration of long-term needs 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 region;
- 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 and identifies the needs;
- Section 7 discusses the needs and provides the alternatives and 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 [1] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs, and the Technical Working Group (TWG) determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company ("LDC") or customer and a Local Plan ("LP") is developed to address them. These needs are local in nature and can be best addressed by a straightforward wires solution.

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.

[1] also referred to as Needs Screening

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 in the region or sub-region.

The RIP phase is the final stage of the regional planning process and involves confirmation of previously identified needs; 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 of this stage is a comprehensive and consolidated report of a wires plan for the region. Once completed, this report can be referenced in 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, plan 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.

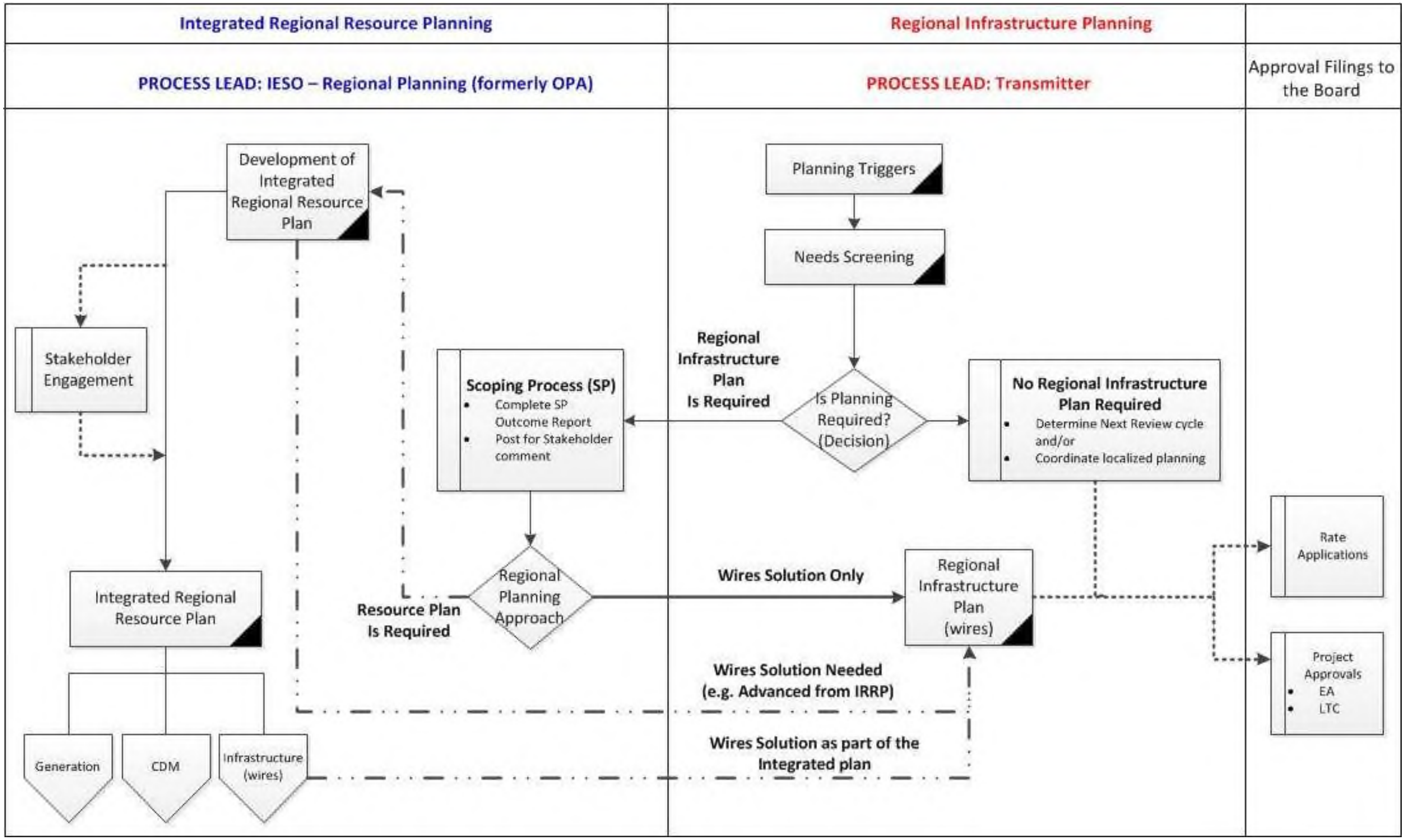

Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of four steps (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 Working Group to reconfirm or update the information as required. The data collected includes:
    - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
    - Existing area network and capabilities including any bulk system power flow assumptions.
    - Other data and assumptions as applicable such as asset conditions, load transfer capabilities, and previously committed transmission and distribution system plans.
2. Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. 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 to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.
4. Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

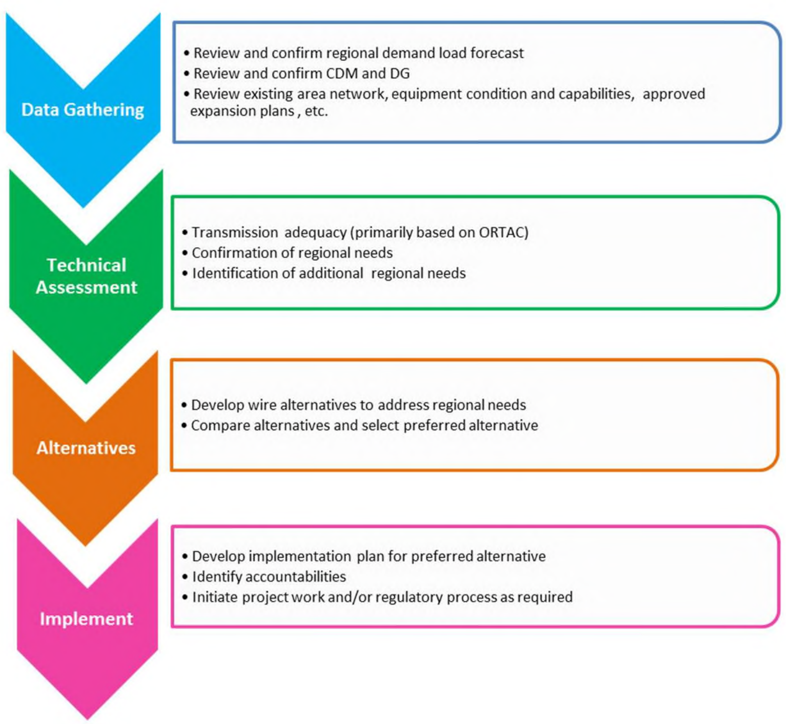

Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE NIAGARA REGION COVERS THE REGIONAL MUNICIPALITY OF NIAGARA AND INCLUDES THE CITIES OF NIAGARA FALLS, PORT COLBORNE, ST. CATHARINES, THOROLD AND WELLAND, THE TOWNS OF FORT ERIE, GRIMSBY, LINCOLN, NIAGARA-ON-THE-LAKE AND PELHAM AND THE TOWNSHIPS OF WAINFLEET AND WEST LINCOLN.

The Local Distribution Companies in the Niagara Region are Alectra Utilities Corporation, Canadian Niagara Power Inc., Grimsby Power Inc., Hydro One Networks Inc. (Distribution), Niagara-on-the-Lake (NOTL) Hydro Inc., Niagara Peninsula Energy Inc., and Welland Hydro Electric System Corp. A listing of the LDCs along with the associated supply stations is given in Appendix C. The high-voltage system in this Region also provides supply to number of direct transmission-connected customers transformer stations.

Electrical supply to the Niagara region is provided through a network of 230kV and 115kV transmission circuits supplied mainly by the local generation from Sir Adam Beck GS #1, Sir Adam Beck GS #2, Decew Falls GS, Thorold GS and the 230kV/115kV autotransformers at Allanburg TS. The 230kV circuits (Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, and Q35M) from Sir Adam Beck #2 SS connect this region to Hamilton/Burlington. The power is distributed through thirteen (13) HONI and six (6) LDC owned step-down transformer stations (please see Appendix B for a complete list. The distribution system in this Region is at two voltage levels, 27.6 kV and 13.8 kV. An electrical single line diagram for the Niagara Region transmission facilities is shown in Figure 3-1. The circuits and stations are provided in Table 3-1.

Table 3-1: Station and Circuits in the Niagara Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
Q3N, Q4N, Q11S, Q12S, A36N, A37N, A6C, A7C, D9HS, D10S, D1A, D3A, Q2AH	Q23BM, Q24HM, Q25BM, Q26M, Q28A, Q29HM, Q30M, Q35M, Q10P	Allanburg TS*, Beamsville TS, Bunting TS, Carlton TS, Crowland TS, Dunnville TS, Glendale TS, Kalar MTS, Niagara Murray TS, Niagara West MTS, NOTL York MTS, NOTL #2 MTS, Port Colborne TS, Stanley TS, Thorold TS, Vansickle TS, Vineland DS, CNPI Station #17 MTS, CNPI Station #18 MTS	Sir Adam Beck GS #1, Sir Adam Beck GS #2, Sir Adam Beck PGS, Thorold CGS, Decew Falls GS

*Station with Autotransformers installed

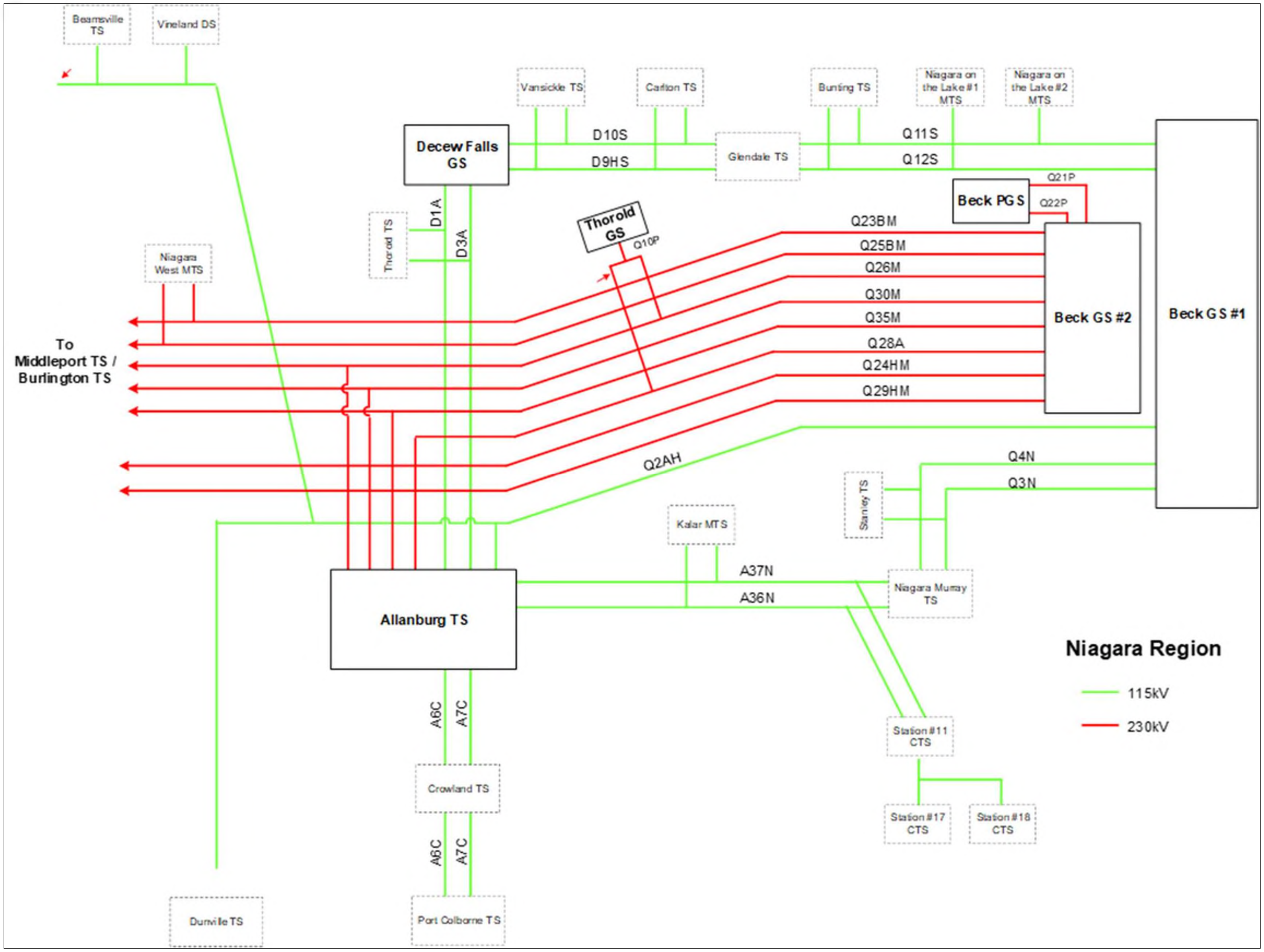

Figure 3-1: Niagara Region Single Line Diagram

4 TRANSMISSION FACILITIES COMPLETED AND/OR UNDERWAY IN THE LAST TEN YEARS

IN THE LAST TEN YEARS A NUMBER OF TRANSMISSION PROJECTS HAVE BEEN PLANNED AND UNDERTAKEN BY HYDRO ONE, OR ARE UNDERWAY, AIMED AT IMPROVING THE SUPPLY CAPABILITY AND RELIABILITY IN THE NIAGARA REGION.

A summary and brief description of the major projects completed and/or currently underway over the last ten years is provided below:

Projects Completed

- Decew Falls SS (2017) – Existing five (5) 115kV breakers were replaced with sulfur hexafluoride (SF6) equivalent breakers to improve supply reliability.

- Q4N Line Section Upgrade (2019) – Line section of 115kV Q4N circuit between Beck SS #1 x Portal Junction section (egress out from the generation station) was upgraded to meet load supply needs.

- A6C Line Section Refurbishment (2020) –115kV A6C circuit line conductor between Crowland TS and Port Colborne TS was replaced. The conductor needed replacement due to its asset condition.

- Stanley TS (2022) – Existing 40/53/67 MVA T2 transformer was replaced with a 45/60/75 MVA unit. This transformer needed replacement due to asset condition. Work at 13.8kV switchyard components and protection and control equipment were also replaced due to asset condition.

- Port Colborne TS (2022) – Existing T61 and T62 28/37/47 MVA transformers was replaced with 50/66.7/83.3 MVA units. These transformers needed replacement due to asset condition. The 27.6kV switchyard components and protection and control equipment were also replaced due to asset condition to improve the reliability of supply.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

A detailed load forecast for the Niagara region was developed as part of the area IRRP study. The TWG participants, including representatives from LDC's, IESO and Hydro One provided information and input for the IRRP Load forecast.

The IRRP forecast used in this RIP study includes minor increases at a few stations as per the LDCs[2]. Also included is a LDC connected industrial customer with curtailable load under specific outage conditions.

The load in the Niagara Region is expected to grow at an average rate of approximately 2.3% annually from 2023 to 2032. However, a major portion of this load increase is due to industrial customers. The growth rate for the LDCs, not accounting for the industrial customers, is about 1.3%. Longer term growth rate between 2033 to 2042 for all customers is forecast to be about 0.9%.

Figure 5-1 shows the Niagara region extreme summer weather net forecast from 2023-2042. The forecast shown is the regional non-coincident forecast and shows the load for all Niagara customers as well as the load for all the LDCs. The regional non-coincident peak load is forecast to increase from approximately 1092MW in 2023 to about 1505MW in 2042.

[2] Loading at Crowland TS adjusted as per new forecast from Welland Hydro. Loading at NOTL #2 MTS and NOTL York MTS adjusted as per new forecast from NOTL Hydro.

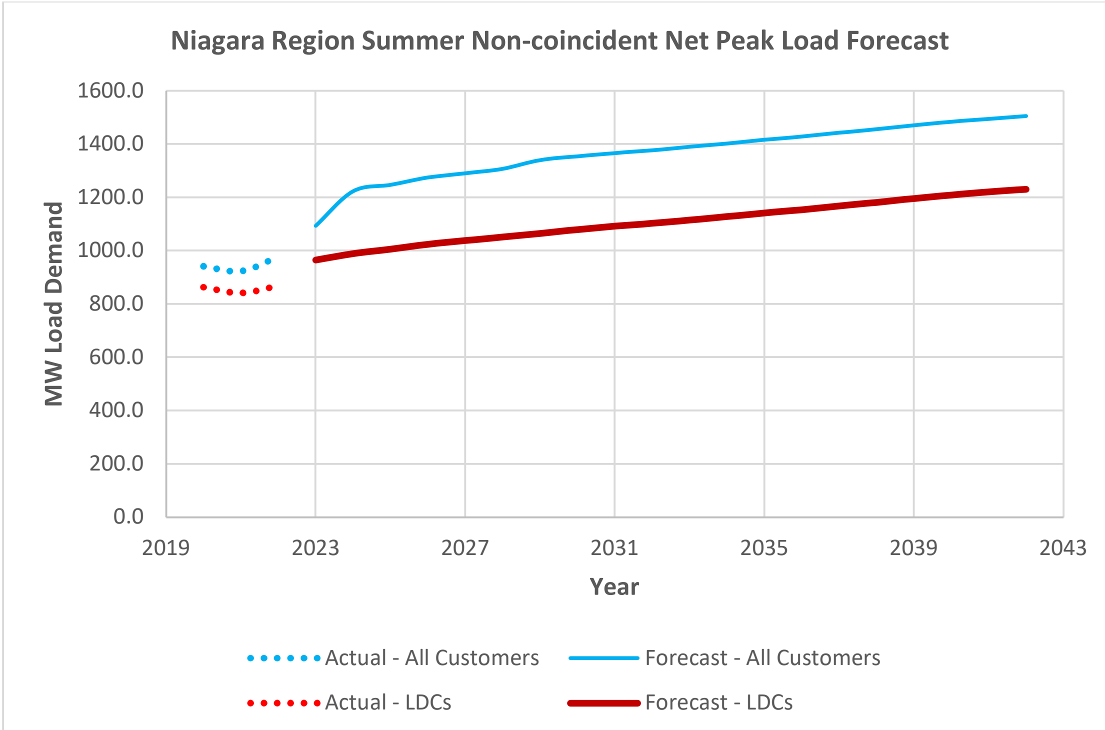

Figure 5-1: Niagara Region Summer Non-Coincident Weather Corrected Forecast

5.2 Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2032. However, a longer term forecast up to 2042 is provided to identify long-term needs and align with the Niagara region IRRP.
- LDCs reconfirmed load forecasts up to 2041. The additional year of forecast to 2042 was extrapolated to complete the 20 year period.
- All planned facilities for which work has been initiated and are listed in Section 4 are assumed to be in-service.
- Summer is the critical period with respect to line and transformer loadings for this region. The assessment is therefore based on summer peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, where the power factor used for the load stations are from the IRRP Appendix G.
- 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. Radial line adequacy is assessed using non-coincident peak loads.
- Adequacy assessment is conducted as per ORTAC.

6 SYSTEM ADEQUACY AND REGIONAL NEEDS

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION SYSTEM AND TRANSFORMER STATION FACILITIES SUPPLYING THE NIAGARA REGION AND LISTS FACILITIES REQUIRING REINFORCEMENT OVER THE 2023-2032 PERIOD.

In the current regional planning cycle, the three regional assessments were completed for the Niagara Region and their findings were used as inputs to this RIP report. These assessments are:

- Niagara Region Needs Assessment (NA) Report, May 2021.
- Niagara Region Scoping Assessment (SA) Report, August 2021
- Niagara Region Integrated Regional Resource Plan (IRRP), December 2022 and Appendices, February 2023

The NA and IRRP reports identified several needs because of the forecasted load demand and condition of major high voltage transmission assets. This section reviews the adequacy of the transmission lines and stations in the Niagara Region based on the updated regional load forecast provided in Appendix C. Sections 6.1 to 6.3 present the results of this review. Asset replacement needs identified in the previous NA report are discussed in Section 6.4 of this report. Load security and load restoration needs are discussed in Section 6.5.

6.1 230 kV and 115kV Transmission Circuits

All 230 kV transmission circuits in the Niagara Region are classified as part of the Bulk Electricity System ("BES"). They connect the Region to the Ontario's transmission system, carry power from the Niagara River Generation to the rest of Ontario and are part of the interconnection path that connects Ontario to neighboring New York State at the Beck 2 SS. The 230 kV circuits Q26M, Q28A, Q30M and Q35M circuits also supply the 230/115 kV autotransformer station at Allanburg TS to serve local area stations within the region. The power flow on these circuits depend on the bulk system transfers as well as the local area loads.

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the Niagara Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 6-1 below. The need date defines the time when the peak load forecast exceeds the most limiting summer Limited Time Ratings. Mitigation measures are discussed in Section 7.1.

Table 6-1: Niagara Region - Lines Sections Exceeding Ratings

No.	Voltage	Line	Section	Contingency	Line Rating MW	Need Date
1	230kV	Q28A	Beck 2 x Abitibi Jct.	N-2[1]	386	2024[2]
2	115kV	A6C/A7C	Allanburg TS x Crowland TS	N-1	214	2029

1. Loss of double circuit line Q26M/Q35M
2. Need date dependent on customer forecast load increase

6.2 230/115kV Transformation Facilities

Almost ninety percent of the Niagara Region load is supplied from the 115 kV transmission system. This power is supplied to the 115kV system through the four 230/115 kV autotransformers at Allanburg TS together with 115kV generation at Sir Adam Beck #1 GS and Decew Falls GS.

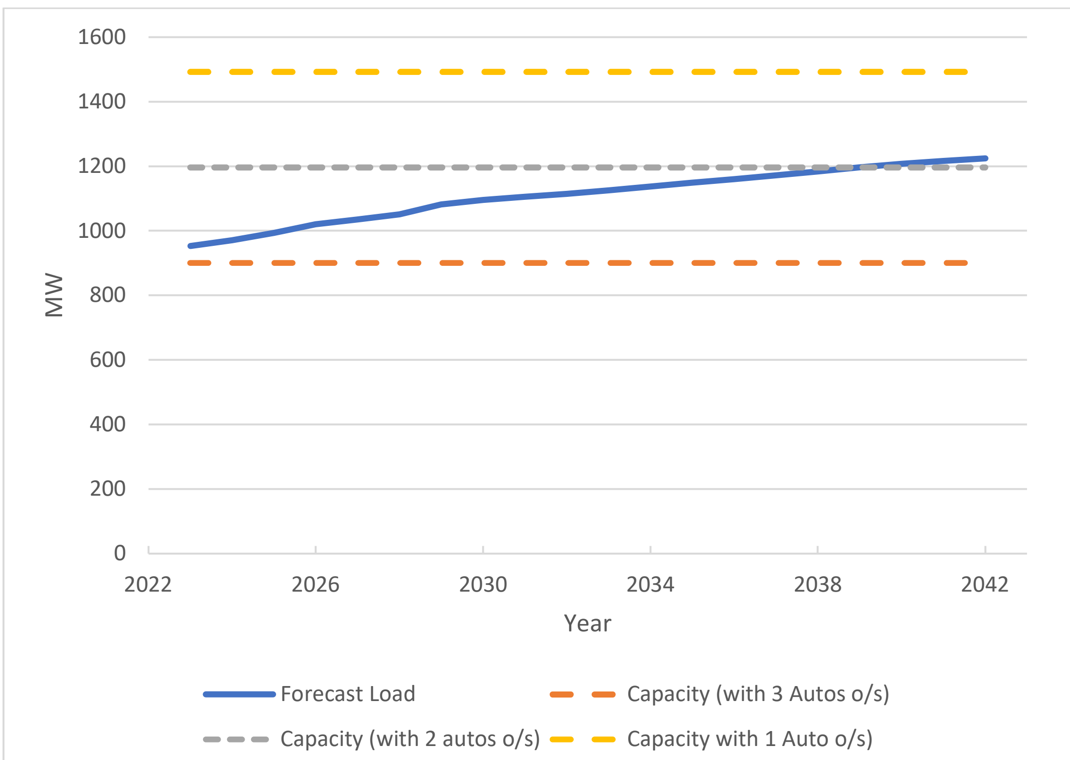

Figure 6-1: Niagara Region – 115kV Area Load and Supply Capacity

The forecast loading on the 115kV system is shown in Figure 6-1, together with the supply capacity with one, two and three autotransformers out of service at Allanburg TS and the local 115kV generation at 605MW[3]. There is adequate supply capacity in the region for the loss of up to 2 of the 4 autotransformers beyond the 2023-2032 RIP study period. However, since the autotransformers are connected to the 230kV circuits directly – loss of up to three autos can occur under an outage condition followed by a double circuit line outage – resulting in load exceeding supply capacity (N-1-2 contingency). Mitigation measures to address this issue are described in Section 7.2.

6.3 Step Down Transformation Facilities

There are a total of twenty-six (26) step-down transformer stations supplying power to customers in the Niagara Region as listed in Table 6-2. These include thirteen stations owned by Hydro One, six by area LDCs and seven (7) by direct industrial customers. The stations' summer peak load forecast is given in Appendix D Table D-1.

Table 6-2: Niagara Region - Step-Down Transformer Stations

Allanburg TS	CNPI Station #18 MTS	Murray TS	Stanley TS
Beamsville TS	Crowland TS	Niagara West MTS	Thorold TS
Bunting TS	Dunnville TS	NOTL #2 MTS	Vansickle TS
Carlton TS	Glendale TS	NOTL York MTS	Vineland DS
CNPI Station #17 MTS	Kalar MTS	Port Colborne TS	CTS #1
CTS #2	CTS #3	CTS #4	CTS #5
CTS #6	CTS #7		

Over the study period 2023-2032 the RIP reviewed the capacity of all the 230kV and 115kV transformer stations within the Niagara 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 study period are shown in Table 6-3.

[3] Beck GS #1 is assumed at 490MW and Decew Falls GS at 115 MW.

The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer) Limited Time Ratings. Mitigation measures to address this issue are described in Section 7.3.

Table 6-3: Niagara Region Station Capacity Needs in the Study Period

No.	Station Name	Capacity (MVA)	2023 Loading (MW)	Station 10- day LTR (MW)	Need Date
1	Beamsville TS	25/42	64.2	59.0	2023
2	Murray TS T11/T12	45/75	77.7	73.2	2023
3	Niagara West MTS	40/67	54.6	66.0	2024
4	Crowland TS	50/83	100.9	101.7	2024
5	Carlton TS	45/75	89.2	95.4	2029

6.4 Asset Replacement Needs for Major High Voltage (HV) Transmission Equipment

Several Hydro One facilities in the Niagara Region will require asset renewal work over the 2023-2032 study period. These needs are determined by asset condition based on a range of considerations such as equipment deterioration, technical obsolescence due to outdated design, lack of spare parts availability or manufacturer support, and/or potential health and safety hazards.

Asset replacement work is planned over the study period at area transformer stations and lines listed in Table 6-4. The options and preferred solutions to address these needs are discussed further in Section 7.4 of the report.

Table 6-4: Niagara Region - Planned Replacement Work

No.	Station	Planned I/S Date
A - Station Work		
1	Thorold TS	2024
2	Glendale TS	2027
3	Murray TS T11/T12	2027
4	Carlton TS	2027
5	Crowland TS	2027
6	Bunting TS	2029
7	Murray TS T13/T14	2031
8	Vansickle TS	2032
9	Allanburg TS	2032
B – Lines Work		
1	115kV D1A/D3A	2024
2	115kV Q2AH	2025

6.5 Load Security and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study and one load security need has been identified for the region. The ORTAC requires that not more than 150MW of load may be interrupted by planned load curtailment or load rejection and the Allanburg Load Rejection scheme does not meet the criteria.

6.5.1 A6C/A7C Load Security

The loss of the 230kV double circuit line Q26M/Q28A, will result in the coincidental loss of autotransformers T1 and T2 at Allanburg TS and the separation of the 115kV A6C/A7C and D1A and A36N circuits from the Allanburg TS 115kV bus. Under this scenario the Allanburg Load Rejection scheme trips the A6C and A7C circuits to prevent loads connected to the A6C/A7C circuits from excessive voltage declines. The load on the A6C/A7C is currently about 200MW and forecast to increase to 278MW by the end of the plan period. The amount of load rejected is thus more than the permitted amount of 150 MW allowed under ORTAC. Mitigation measures to address this need are discussed in Section 7.5.

7 REGIONAL PLANS

THIS SECTION DISCUSSES NEEDS, PRESENTS WIRES ALTERNATIVES AND THE PREFERRED WIRES SOLUTIONS FOR ADDRESSING THE ELECTRICAL SUPPLY NEEDS FOR THE NIAGARA REGION.

The electrical infrastructure needs for the Niagara Region are summarized in Table 7-1. These needs include those previously identified in the Niagara Region NA and IRRP as well as those resulting from the adequacy assessment carried out as part of this RIP report. The details of the project/plan to address these needs are provided in Sections 7.1 through 7.5.

Table 7-1: Niagara Region – Identified Near and Medium-Term Needs

Section	Facilities	Need	Timing
Transmission Line Capacity Needs			
7.1.1	Q28A -Beck 2 TS to Abitibi Jct.	Line Capacity Exceeded	2024
7.1.2	115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS	Line Capacity Exceeded	2029
230/115 kV Transformation Capacity/115kV Supply Area Capacity			
7.2	Allanburg TS	Loading exceeds Capacity at Allanburg TS	2023
Station Capacity			
7.3.1	Beamsville TS and Niagara West MTS	Forecast load exceeds normal supply capacity	2023
7.3.2	Crowland TS	Forecast load exceed normal supply capacity	2024
7.3.3	Murray TS and Kalar TS	Forecast load exceed normal supply capacity	2028
7.3.4	Carlton TS	Forecast load exceed normal supply capacity	2029
Asset Replacement			
7.4	Thorold TS	Transformer T1 replacement	2024
7.4	Carlton TS	LV Switchyard refurbishment	2027
7.4	Glendale TS	Transformers T1 and T2 replacement	2027
7.4	Crowland TS	Transformer T5 and T6 replacement	2027
7.4	Murray TS	Transformers T11 and T12 replacement	2027
7.4	Bunting TS	Transformers T1 and T2 replacement	2029
7.4	Murray TS	Transformers T13 and T14 replacement	2031
7.4	Vansickle TS	LV Switchyard refurbishment	2032
7.4	Allanburg TS	Transformer T3 replacement	2032
7.4	115kV Line D1A/D3A	Gibson Jct. x Thorold TS	2024
7.4	115kV Line Q2AH	Rosedene Jct. x St. Anns Jct.	2025
Load Security			
7.5	115kV A6C/A7C Load Security	Forecast exceeds ORTAC load rejection Criteria	2023

7.1 Transmission Line Capacity

This section describes work required to address the transmission line capacity needs associated with the 230kV circuit Q28A and 115kV circuits A6C and A7C as described in Section 6.1.

7.1.1 230kV circuit Q28A – Beck #2 TS x Abitibi Junction

7.1.1.1 Introduction

The 230kV circuit Q28A is part of the eight transmission circuits egressing from Beck #2 GS and connects to Allanburg TS. The planning forecast based on new customer load indicates that the loading will exceed the circuit 980A rating by summer 2024 for a loss of the double circuit line Q26M/Q35M.

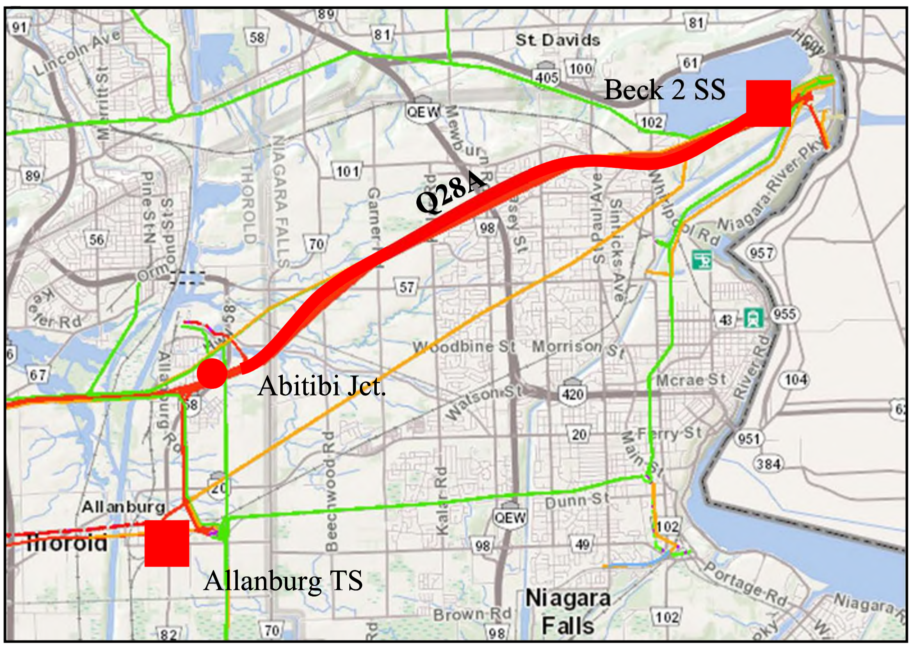

Figure 7-1: Uprate Q28A Circuit

7.1.1.2 Alternatives and Recommendation

The following alternatives were considered to address the 230kV circuit Q28A capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate 230kV Q28A Circuit:** This alternative considers uprating the conductor by tensioning the conductors to reduce the line sag and allow the line conductor to operate at a higher temperature. This will increase the circuit rating from 980A to 1310A. The estimated cost of the work is about $3M.

The TWG recommends Alternative 2 as the preferred and cost-effective alternative for increasing the capacity of the line. Hydro One has advised the customer of the proposed work and will initiate the work once confirmed by the customer.

7.1.2 115 kV Circuits A6C and A7C – Allanburg TS to Crowland TS

7.1.2.1 Introduction

The 115 kV double circuit line A6C/A7C supplies Crowland TS and Port Colborne TS along with several directly connected transmission customers as shown in Figure 7-2. The load connected on this line is forecast to exceed the line capacity by summer 2029 as shown in Table 7-2.

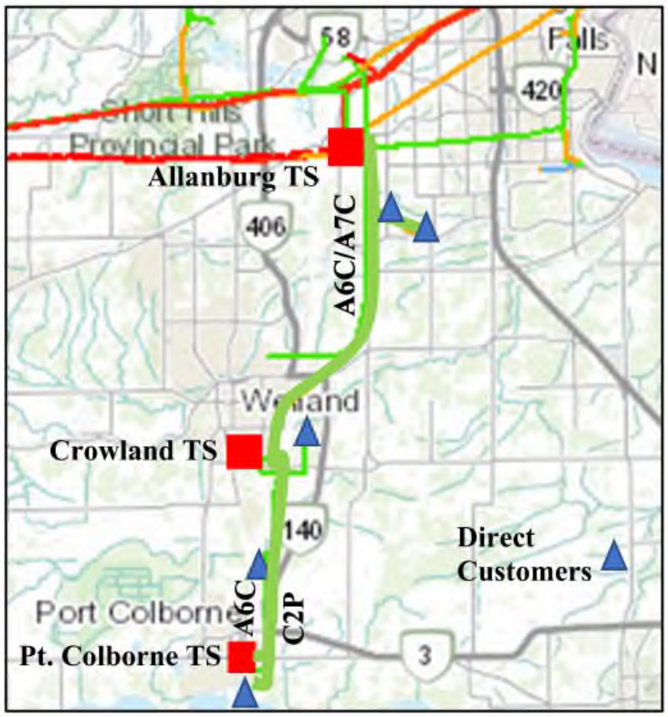

Figure 7-2: Map of 115kV A6C/A7C Circuits

Table 7-2: 115kV circuit A6C/A7C -Connected Loads

Load	Circuit Limit	Act.[1]	Load Forecast										Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
A6C/A7C[2]	213.9[3]	169.5	174.0	182.4	191.6	202.2	206.8	211.6	232.7	234.9	236.8	236.9	246.1	2029
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	---
A6C/A7C post Crowland[4]			-	-	-	-	92.7	95.7	115.1	115.3	115.5	115.7	117.6	---

1. Actual summer load adjusted for extreme weather
2. Loading excludes Allanburg TS DESN
3. Rating of A6C/A7C circuit between Allanburg TS DESN and Crowland TS

4. After Crowland TS conversion to 230KV as per Section 7.3.2 in 2027

7.1.2.2 Alternatives and Recommendation

The following alternatives were considered to address the overloading issue on the 115kV line A6C/A7C line:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.
- **Alternative 2 – Uprate the A6C and A7C Circuits:** This alternative considers reconductoring the A6C/A7C line between Allanburg TS and Crowland TS (~ 14.5 km) using a higher rated conductor. This will increase the circuit rating from 214 MW to about 280 MW. The estimated cost of the work is $23M.
- **Alternative 3 – Reduce Loading on A6C/A7C:** This alternative reduces loading on circuits A6C and A7C by rebuilding Crowland TS[4] as a 230/27.6 kV station supplied from and supplying it from a new 230kV circuit line.

The TWG recommends Alternative 3 as the preferred and cost-effective alternative addressing the overloading issue on the A6C/A7C line. Transferring of Crowland TS to a 230 kV supply also addresses multiple other issues; reduces load on the Allanburg TS autotransformers (See Section 7.2.2), allows increase capacity at Crowland TS (see Section 7.3.2), and reduces the severity of the load security issue (Section 7.5).

7.2 115kV Supply Area Capacity

7.2.1 Introduction

As shown in Section 6.2, the loads on the Niagara Region 115kV system exceeds the 115 kV system supply capability under certain contingency conditions which result in three out of the four autotransformers being out of service at Allanburg TS. Specifically, this occurs under a 230kV outage condition followed by a double 230kV circuit line outage (N-1-2 contingency).

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the 115 kV supply capacity:

- **Alternative 1 – Maintain Status Quo:** This alternative is not viable as it does not address meeting the area customers' load requirements. It is therefore not considered further.

[4] Crowland TS needs to be refurbished and will be rebuilt. Please refer to Section 7.3.2 and 7.4 for more details.

- **Alternative 2 – Modify Existing Load Rejection Scheme for 115kV Subsystem:** This alternative modifies the Allanburg load rejection scheme to include rejection of up to 150MW of load whenever three autotransformers are out. The estimated cost of this alternative is about $8M.
- **Alternative 3 – New 230kV Switchyard at Allanburg TS:** The work required in this alternative is to build a new 230kV switchyard to eliminate the N-1-2 contingency at Allanburg TS (loss of three autotransformers contingency) to supply more power to the 115kV network. The work required would consist of four new 230kV bus diameters, each accommodate an autotransformer to eliminate any coincidental loss of the autotransformers. This work has an estimated cost of $253M.
- **Alternative 4** – **Reduce load on 115kV system by introducing 230kV Supply to the Welland Area -** This alternative would transfer Crowland TS to 230kV supply by building a 18km double circuit 230kV transmission line from Q24HM/Q29HM to connect to a new 230/27.6kV transformer station at the Crowland TS site. The new TS will replace the existing station that requires replacement. This work has an estimated cost of $128M.

The TWG recommends Alternative 4 as the most cost effective and preferred alternative. Besides addressing the 115kV supply capacity needs, this alternative also addresses; the A6C/A7C overloading issue (Section 7.1.2); the Crowland TS capacity needs (Section 7.3.2); the Crowland TS asset renewal needs (Section 7.4); and reduces the severity of the A6C/A7C load security issue (Section 7.5). The work is planned to be in service by summer 2027.

7.3 Station Capacity Needs

This section describes the work required to address the station capacity needs identified in Section 6.3.

7.3.1 Beamsville TS, Vineland DS, Niagara West MTS – 115kV Lincoln Area

7.3.1.1 Introduction

Beamsville TS and Vineland DS are 115/27.6kV stations and Niagara West MTS is a 230/27.6kV station which supplies the towns of Grimsby, West Lincoln, and Lincoln. The area is experiencing load growth where the summer weather extreme demand forecast will exceed the area normal supply capacity.

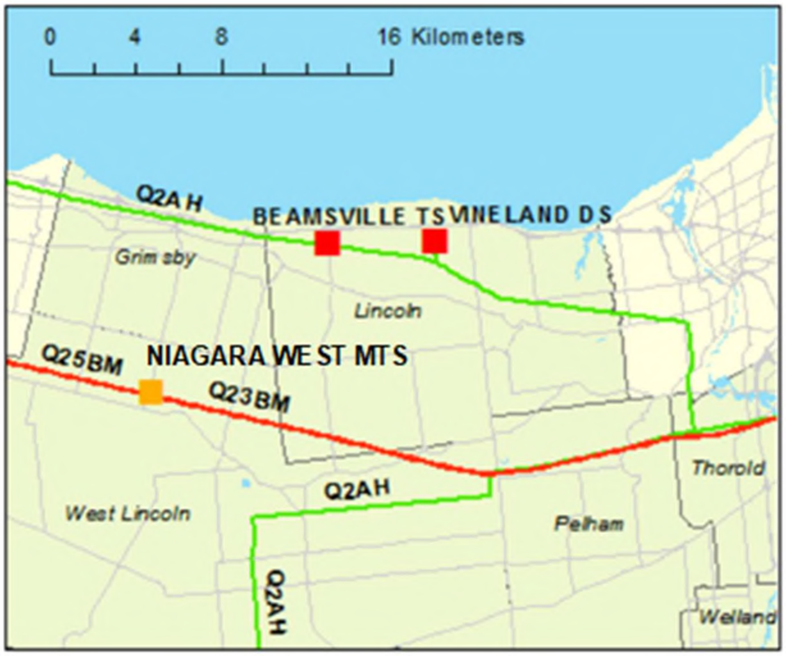

Figure 7-3: Map of 115kV Lincoln Area

Beamsville TS presently has 115kV/27.6kV 42MVA transformers (T3/T4) with a summer LTR of 59.0MW. This station has operated at or slightly over the LTR over the past few years.

Table 7-3 shows the forecast for the three area stations. The forecast shows that the combined capacity of the three stations would be exceeded by summer 2024. The TWG agrees that a solution is required to address the upcoming supply capacity needs.

Table 7-3: 115kV Lincoln Area Stations Load Forecast

Station	LTR MW	Act. [1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Beamsville	59.0	63.1	77.2	79.2	80.5	81.4	82.1	82.9	83.7	84.6	85.6	86.5	101.9	---
Niagara West MTS[2]	63.4	41.6	49.0	56.8	57.6	58.2	58.9	60.3	61.7	63.2	64.7	66.2	84.3	---
Vineland DS	26.4	20.5	20.7	20.9	21.1	21.3	21.6	22.5	23.5	24.5	24.7	25.0	27.6	---
Total	148.8	125.3	147.0	156.9	159.2	161.0	162.5	165.7	168.9	172.3	175.0	177.7	213.8	2024

1. Actual summer load adjusted for extreme weather

7.3.1.2 Alternatives and Recommendation

The following alternatives were considered to address the area capacity need:

- **Alternative 1 – Maintain Status Quo:** This solution is not recommended as it does not address the supply capacity needed in the area. This solution will also prevent load growth in this area.

- **Alternative 2 – Load Transfer to Neighbouring Stations:** This solution is not viable as there is no nearby station where the load can be transferred.
- **Alternative 3 – Replace Beamsville and Niagara West transformers:** Replace existing Beamsville TS T3/T4 transformers and Niagara West MTS T1/T2 with larger 50/83MVA units, providing total additional capacity of 100 MW at both stations to address the existing and future load demand. Additional feeder positions will be required at both stations to utilize the additional capacity. The cost of this work is estimated to be about $48M.
- **Alternative 4 – Build new 230/27.6kV DESN station in Local Area:** This alternative would build a new 230/27.6kV DESN station to supply the increased load demand forecast required in the local area. The new station would be supplied by the double circuit 230kV transmission line Q23BM/Q25BM with new 50/83MVA transformers. The new station will provide about 102 MW of new capacity. The estimated cost of this alternative is about $45M.

The TWG recommends proceeding with Alternative 4. This alternative provides a robust transmission solution to meeting the area LDCs demand forecast and will also allow for future load growth beyond the study period on the 230kV system. This solution will also provide better reliability for future loads as the new station will have dual incoming transmission supplies into station instead of being on a single supply like Beamsville TS. Loads will be managed by the respective LDCs between 2024 and 2027 when the new facility is expected to go into service.

Hydro One will work with all the respective parties to find a suitable location to meet the load. Possible locations could be an expansion at Niagara West MTS or a location central to Vineland DS and Beamsville TS to supply local growth (e.g., the southwest corner in the Town of Lincoln).

7.3.2 Crowland TS

7.3.2.1 Introduction

Crowland TS is a 115/27.6kV 50/83MVA transformer station located in Welland. The station load is at or near its 10-day LTR of 101.7 MW and load is forecasted[5] to increase up to 121MW by the end of 2032 as shown in Table 7-4 below. A permanent supply solution is required for the increased load growth as the current loading will surpass the station capacity in 2024.

The transformers, T5 and T6, at Crowland TS are about 55 years old and based on asset condition assessment Crowland TS has been identified for asset renewal by summer 2027.

[5] Forecast updated from IRRP as per Welland Hydro

Figure 7-4: Map of Crowland TS

Table 7-4: Crowland TS Load Forecast

Station	LTR MW	Act.[1]	Load Forecast										Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Crowland TS	101.7	93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5	2024

1. Actual summer load adjusted for extreme weather

7.3.2.2 Alternatives and Recommendation

The following alternatives were considered to address Crowland 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 – Rebuild existing DESN at Crowland TS and add a second DESN at Crowland TS:** Under this alternative the existing Crowland TS transformers will be replaced, and the station refurbished. A new second DESN would be built to handle the increased load. This alternative would maintain the existing 115kV loading on the Allanburg autotransformers and work will be required to address the issue. Work also would be required to address the capacity need on the A6C/A7C circuits and address the load security concern at Allanburg TS. This alternative is estimated to cost $78M for the refurbishment work and new DESN at Crowland TS. An additional $253M will be required to provide additional switching at Allanburg TS to reinforce the 115kV supply.

- **Alternative 3 – Provide a new 230kV Supply to Welland Area and convert Crowland TS to 230kV:** Under this alternative the existing Crowland TS would be replaced with a new 230/27.6 kV DESN station with 75/125 MVA transformers to supply the increased load demand. A new 18km double circuit 230kV transmission line will be constructed to supply this new transformer station from the double circuit 230 kV line Q24HM/Q29HM. This new station would allow the station LTR to increase to approximately 170 MW (summer) with 75/125MVA transformers. The estimated cost of this alternative is about $128M.

The TWG recommends Alternative 3 as it is the lowest cost alternative. It provides new area transmission and load growth opportunities. The conversion of Crowland TS to 230kV will reduce the loading on the 115kV autotransformer at Allanburg TS, alleviating the constrained supply to the 115 kV sub-system described previously. It will also remove the existing Crowland TS loads from the 115kV A6C/A7C circuits, alleviating the severity of the load security constraint at Allanburg TS. This alternative will also provide a parallel opportunity for load growth on the 115kV A6C/A7C circuits as the Crowland TS load is removed from the 115kV system.

7.3.3 Murray TS and Kalar MTS – Niagara Falls

7.3.3.1 Introduction

Murray TS and Kalar TS are two transformer stations located in Niagara Falls. Murray TS has two 115/13.8 DESNs, T11/T12 and T13/T14, with a summer LTR of 73.2MW and 79.8MW respectively. Kalar MTS has one 115/13.8 kV DESN with a summer LTR of 72.0 MW. The stations forecast loads are given in Table 7-5. Considerable new loads are expected to connect in the area. Loading on the Murray TS T11/T12 DESN is forecast to exceed its LTR by summer 2023. Loading on Kalar MTS is forecast to exceed LTR by summer 2028.

The Murray TS transformers, T11, T12, T13 and T14 are between 46 and 52 years old and have been identified for replacement due to asset condition. It is planned to replace T11 and T12 by summer 2027. This will be followed by the replacement of the T13 and T14 transformers by summer 2031.

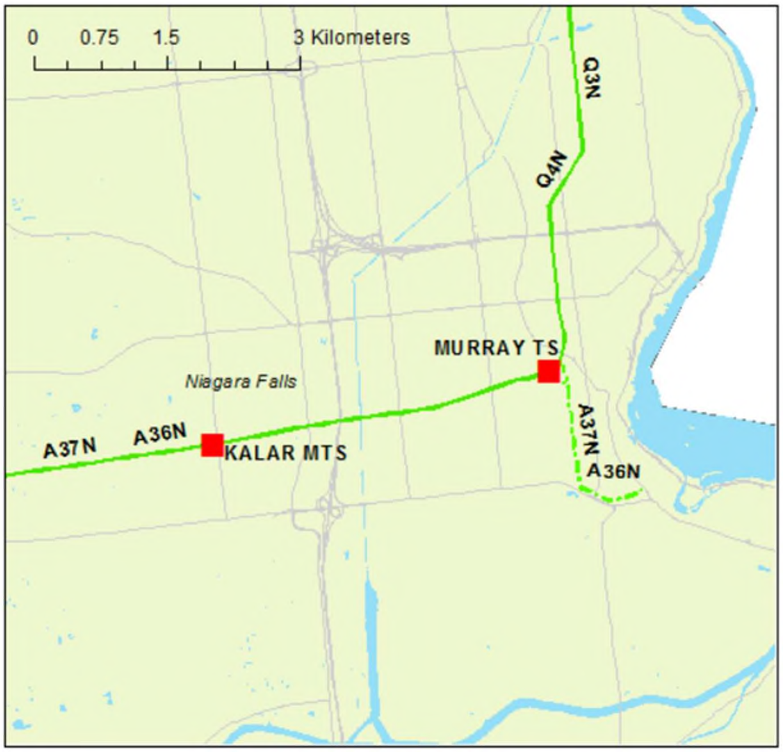

Figure 7-5: Map of Murray TS and Kalar MTS

Table 7-5: Murray TS, and Kalar MTS Load Forecast

Station	LTR MW	Act[1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Murray TS T11/T12	73.2	66.3	77.7	77.7	77.8	78.0	77.9	78.1	78.3	78.7	78.9	79.1	86.2	2023[2]
Murray TS T13/T14	79.8	41.7	42.0	42.2	42.4	42.6	42.9	43.1	43.3	43.5	43.8	44.0	46.6	Note[3]
Kalar MTS	72.0	46.5	46.9	47.4	54.2	60.7	64.4	65.8	67.1	68.6	68.8	69.0	75.1	2039
Total	225.0	166.3	166.6	167.3	174.4	181.3	185.2	187.0	188.7	190.8	191.5	192.1	207.9	

1. Actual summer load adjusted for extreme weather
2. Earliest replacement to happen by 2027
3. The transformers T13 and T14 will be replaced in 2031as per asset condition.

7.3.3.2 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the need as the near and mid-term load forecast exceeds the LTR at Murray TS T11/T12. Asset renewal needs are also not addressed.
- **Alternative 2 – Replace T11/T12 at Murray TS with 60/100MVA transformers:** This alternative would replace the T11/T12 transformers with larger 60/100MVA transformers, with an approximate

LTR of 130MW instead of the 45/60/75MVA units specified for the asset renewal project at Murray TS. This will increase supply capacity of approximately 43MW at Murray TS at an estimated incremental cost of $2M to the asset renewal upgrade cost of $39M. The earliest this work can be done is summer 2027.

- **Alternative 3 – Transfer T11/T12 load to T13/T14 at Murray TS:** This alternative would transfer load from T11/T12 to T13/T14 at a cost of $5M. The T13/T14 bus supplies a large industrial load customer with fluctuating load and customers connected to the bus would experience power quality issues.
- **Alternative 4 – Build new 115kV/13.8kV Station near Kalar MTS:** This alternative would build a new 115/13.8kV DESN station with 25/41.7MVA transformers to supply the increased load demand forecast required at Kalar MTS and Murray TS T11/T12. This new station would provide the station an LTR of 51MW (summer). The estimated cost for this alternative is expected to be $40M.

The TWG recommends Alternative 2 as the preferred alternative for addressing the capacity need as it is the most economical alternative with the ability to increase supply capacity. Alternative 3 is not recommended since is more expensive, will introduce power quality issues to the transferred load and is not acceptable to the LDC. Loading will be monitored and managed at Murray TS by the LDC and Hydro One in the interim before the additional capacity is provided in 2027. The Kalar MTS load growth will be monitored to verify if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and can transfer the extra load from Kalar MTS to Murray TS.

7.3.4 Carlton TS and Bunting TS – St. Catharines

Carlton TS and Bunting TS are two transformer stations located in St. Catharines. Carlton TS has one 115/13.8 kV T1/T2 DESN with a summer LTR of 95.4 MW. Bunting TS has one 115/13.6 kV T1/T2 DESN with a summer LTR of 78.2 MW. The stations forecast loads are given in Table 7-6. Loading on Carlton TS is forecast to exceed its LTR by summer 2029. Bunting TS is adequate over the study period.

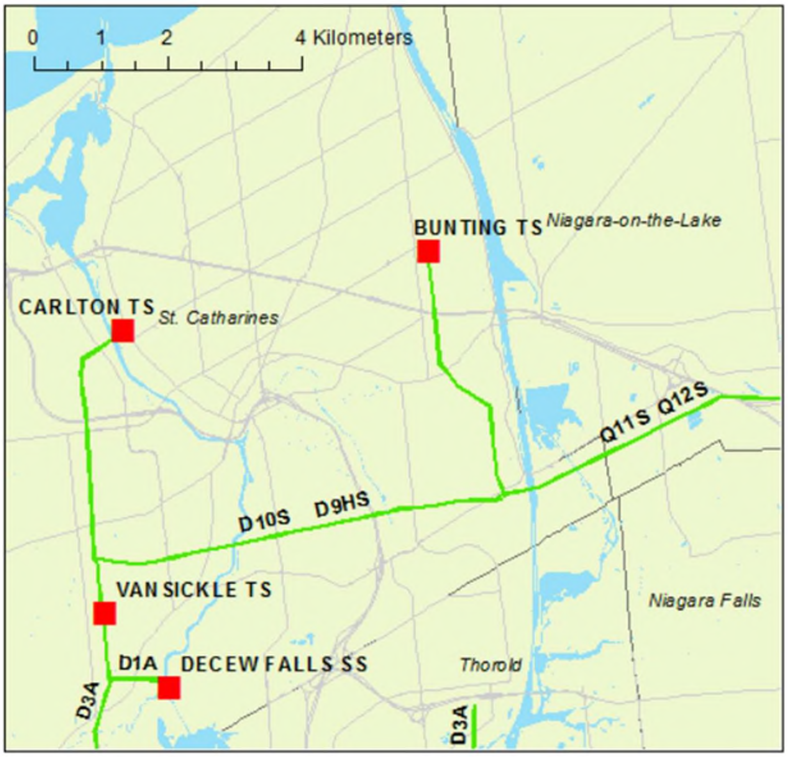

Figure 7-6: Map of Carlton TS and Bunting TS

Table 7-6: Carlton TS and Bunting TS Load Forecast

Station	LTR MW	Act. [1]	Load Forecast											Need Date
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042	
Carlton TS	95.4	82.6	89.2	90.1	91.1	92.2	93.3	94.6	95.9	97.3	98.9	100.3	105.7	2029
Bunting TS	78.2	54.4	57.8	58.3	58.8	59.6	60.4	61.4	62.4	63.6	64.7	65.9	77.1	---
Total	173.6	137.0	147.1	148.4	149.9	151.8	153.7	156.0	158.3	160.9	163.6	166.2	182.8	----

1. Actual summer load adjusted for extreme weather

Both Carlton TS and Bunting TS also have renewal work planned. The LV switchyard at Carlton TS is over 50 years old and refurbishment is required. The Transformer T3 at Bunting TS is also over 50 years and identified for replacement.

7.3.4.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the stations sustainment need. Carlton TS load also exceeds its LTR and action is required to address the issue.

- **Alternative 2 –Carry out Asset Renewal at Carlton TS and Bunting TS**: Monitor Carlton TS loading and transfer excess load to Bunting TS: The station refurbishment work will be carried out at both stations. Carlton TS load growth will be monitored to see if the actual summer peak loads are close to the mid-term forecast. When the actual load is approaching the forecast, the respective LDC will re-evaluate and transfer the excess load over the LTR from Carlton TS to Bunting TS. The cost to transfer the load between stations is estimated to be $5M.

The TWG recommendation is that it is prudent to monitor the area load and complete load transfer at nearby stations with available station capacity when required. The TWG recommends Alternative 2 as the preferred and cost-effective alternative for addressing the need.

7.4 Asset Replacement for Major HV Transmission Equipment

As discussed in Section 6.3, Hydro One has identified the need for replacement of major HV transmission assets over the next ten years at several Niagara Region Hydro One stations as well as two small line sections. Details of the work along with its planned in-service year is given in Table 7-7.

Table 7-7: Niagara Region – Asset Replacement Plans

No.	Station /Line	Planned Work	Planned I/S Date[1]
1	Thorold TS	Replace the existing 45/60/75 MVA T1 transformer with a new 45/60/75 MVA unit.	2024
2	Glendale TS	Replace the existing T1/T2 45/60/75 MVA transformers, with new 45/60/75 MVA units.	2027
3	Crowland TS	The existing 115/27.6 kV T5/T6 DESN will be replaced by a new 230/27.6 kV DESN rated for 170 MW.	2027
4	Murray TS	Replace the existing 45/60/75 MVA transformers T11 and T12 with new 60/80/100 MVA units. Replace the existing 45/60/75 MVA transformers T13 and T14 with new 60/80/100MVA units.	2027 2031
5	Bunting TS	Replace the existing 40/53/67 MVA transformers, with new 45/60/75 MVA units	2029
6	Vansickle TS	Replace LV Switchgear	2032
7	Allanburg TS	Replace Autotransformer T3	2032
8	115kV Line D1A/D3A	115kV kV line refurbishment of a 5 km line section between Gibson Jct and Thorold TS with conductor to be replaced due to asset condition	2024
9	115kV Line Q2AH	115kV line refurbishment of 11.2km between Rosedene Jct. and St. Anns Jct. with conductor to be replaced due to asset condition	2025

1. The planned in-service date is tentative and is subject to change

The TWG recommends that Hydro One proceed with the above work to ensure that the system meets reliability criteria and supply to customers is not affected.

7.5 Load Security – 115kV circuits A6C/A7C

As discussed in Section 6.4.1 the *Allanburg Load Rejection scheme* trips 115kV circuits A6C/A7C under certain contingencies to prevent stations supplied from these circuits being subjected to excessive voltage declines.

The *Allanburg Load Rejection Scheme* is designed to address post contingency voltage decline issues following the coincident loss of Allanburg 230/115 kV Autotransformers T1 and T2. The coincidental loss of Allanburg T1 and T2 transformers will result in circuits A6C and A7C being disconnected from the Allanburg TS 115kV and buses radially connected to circuits D1A and A36N, respectively. As such, this causes excessive voltage to decline at stations supplied from circuits 115kV A6C and A7C. The scheme rejects the load connected to circuits A6C and A7C and will prevent the radial feeds (from Decew Fall GS on D1A and the Niagara Corridor on A36N) from trying to support the load of A6C and A7C.

The load security need arises from Section 7.1 of the ORTAC. As defined under this section, Not more than 150MW of load may be interrupted by configuration and by planned load curtailment or load rejection, excluding voluntary demand management. The A6C/A7C load forecast is provided in Table 7-8.

Table 7-8: 115kV Circuit A6C/A7C -Connected loads

Load	ORTAC L/R Limit	Act.[1]	Load Forecast										
		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2042
A6C/A7C	150	209.6	219.3	227.8	237.1	247.9	252.6	257.5	278.7	281.1	283.1	283.4	297.0
Crowland TS		93.6	100.9	108.8	110.6	112.6	114.1	115.9	117.6	119.6	121.3	121.2	128.5
A6C/A7C post Crowland[2]		-	-	-	-	-	138.5	141.7	161.2	161.5	161.9	162.2	168.5

1. Actual summer load adjusted for extreme weather
2. After Crowland TS conversion to 230KV as per Section 7.3.2

This forecast exceeds the permissible limit set by ORTAC. It also exceeds the A6C/A7C line limit for loss of one of the two circuits.

7.5.1.1 Alternatives and Recommendation

The following alternatives were considered to address the current and future capacity need:

- **Alternative 1 – Maintain Status Quo:** This alternative was considered and rejected as it does not address the ORTAC load security need.
- **Alternative 2 – Reduce Loading on A6C/A7C:** This alternative reduce loading on 115kV circuits A6C and A7C by removing Crowland TS from the A6C/A7C supply. Crowland TS is rebuilt as a 230/27.6 kV station supplied from a new 230kV double circuit line.

The TWG recommends Alternative 2 as the preferred alternative to addressing the load security issue in the ORTAC. This alternative will be partially addressed by converting Crowland TS to a 230kV supply as described in Section 7.3.2. Since the Crowland TS work will not be completed till 2027, the issue will be managed by operational measures. Load can be restored within 15 minutes by opening both T1 and T2 disconnect switches and supplying all the Allanburg 115kV load from the remaining T3 and T4 autotransformers during a coincident T1 and T2 outage. This work reduces the severity of the load security issue. The loading on the A6C/A7C will continue to be monitored and reviewed in the next planning cycle with the option to transfer Allanburg TS DESN to 230kV.

8 CONCLUSION AND RECOMMENDATION

This Regional Infrastructure Plan report concludes the Regional Planning process for the Niagara Region.

The major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon 2023-2032 are provided in Table 8-1 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 8-1: Recommended Plans over the next 10 Years

No.	Need	Recommended Action Plan	Lead	Timing[1]	Budgetary Estimates[2]
1	230 kV circuit Q28A – Additional capacity required	Uprate circuits between Beck 2 SS and Abitibi Jct. to meet expected load demand	Hydro One	TBD[3]	$3M
2	Loading in the Lincoln area exceeding supply capability	Build new 2 x 50/83MVA, 230kV/27.6 station	Hydro One	2028	$45M
3	Crowland TS: Station loading exceeds LTR	Build new 2 x 75/125MVA, 230kV/27.6 station and a new 18 km line from Abitibi Jct to Crowland TS	Hydro One	2027	$128M
4	Murray TS T11/T12 DESN: DESN loading exceeds LTR. Transformers T11/T12 need to be replaced	Replace existing 45/75MVA transformers with larger 60/100MVA units	Hydro One	2027	$41M
5	Carlton TS: T1/T2 DESN loading exceeds LTR	Transfer excess load to Bunting TS	Alectra	2029	$5M
6	**Asset Replacement:** Thorold TS Glendale TS Carlton TS Bunting TS Murray TS T13/T14 Vansickle TS Allanburg TS 115kV Line D1A/D3A 115kV Line Q2AH	Refurbish/replace major high voltage transmission equipment	Hydro One	 2024 2027 2027 2029 2031 2032 2032 2024 2025	 $43M $55M $55M $45M $27M $14M $20M $4M $10M

1. The 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)
3. Contingent on customer

9 REFERENCES

[1] Niagara Region Integrated Resource Plan - Dec 2022

[2] Niagara Region NA report - May 2021

[3] Niagara Region Regional Infrastructure Plan Report - March 2017

APPENDIX A: NIAGARA REGION - STEP-DOWN TRANSFORMER STATIONS AND SUPPLY CIRCUITS

No.	Transformer Station	Voltage (kV)	Supply Circuits
1	Allanburg TS	115	A6C/A7C
2	Beamsville TS	115	Q2AH
3	Bunting TS	115	Q11S/Q12S
4	Carlton TS	115	D9HS/D10S
5	CNPI Station #17 MTS	115	A37N
6	CNPI Station #18 MTS	115	A37N
7	Crowland TS	115	A6C/A7C
8	Dunnville TS	115	Q2AH
9	Glendale TS	115	Q11S/Q12S, D9HS/D10S
10	Kalar MTS	115	A36N/A37N
11	Murray TS	115	A36N/A37N
12	Niagara West MTS	230	Q23BM/Q25BM
13	NOTL #2 MTS	115	Q11S
14	NOTL York MTS	115	Q12S
15	Port Colborne TS	115	A6C/A7C
16	Stanley TS	115	Q3N/Q4N
17	Thorold TS	115	D1A/D3A
18	Vansickle TS	115	D9HS/D10S
19	Vineland DS	115	Q2AH

APPENDIX B: NIAGARA REGION - DISTRIBUTORS

No.	Name of LDC
1	Alectra Utilities
2	Canadian Niagara Power Inc.
3	Grimsby Power Inc.
4	Hydro One Networks Inc. (Distribution)
6	Niagara-on-the-Lake Hydro Inc.
7	Niagara Peninsula Energy Inc.
8	Welland Hydro Electric System Corp.

APPENDIX C: NIAGARA REGION – STATIONS LOAD FORECAST (MW)

Station	LTR MW	2022 Actual[1]	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042
Allanburg TS	58.7	40	45	45	45	46	46	46	46	46	46	47	47	47	48	48	49	49	50	50	51	51
Beamsville TS	59.0	63	77	79	81	81	82	83	84	85	86	86	88	89	90	92	93	95	97	98	100	102
Bunting TS	78.2	54	58	58	59	60	60	61	62	64	65	66	67	68	70	71	73	74	76	77	77	77
Carlton TS	95.4	83	89	90	91	92	93	95	96	97	99	100	102	104	106	105	105	105	105	106	106	106
CNPI Station #17 MTS	59.4	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	26	27	27
CNPI Station #18 MTS	59.4	37	36	36	36	36	36	35	35	35	35	35	35	35	35	35	35	36	36	36	36	36
Crowland TS	101.7	94	101	109	111	113	114	116	118	120	121	121	121	122	122	123	124	125	126	126	128	129
Dunnville TS	53.3	30	36	36	37	37	37	38	38	38	39	39	39	40	40	40	41	41	41	42	42	42
Glendale TS (T1/T2)	96.3	41	31	32	32	32	33	33	34	35	35	36	37	37	38	39	40	40	41	42	42	42
Glendale TS (T3/T4)	20.1	14	6	6	6	7	7	7	7	7	8	8	8	9	9	9	10	10	10	11	11	11
Kalar MTS	72.0	44	47	47	54	61	64	66	67	69	69	69	69	70	70	71	72	72	73	74	75	75
Murray TS (T11/T12)	73.2	66	78	78	78	78	78	78	78	79	79	79	79	80	80	81	82	83	83	84	85	86
Murray TS (T13/T14)	79.8	44	42	42	42	43	43	43	43	44	44	44	44	45	45	45	45	45	46	46	46	47
Niagara West MTS	63.4	41	49	57	58	58	59	60	62	63	65	66	68	69	71	73	75	77	78	80	82	84
NOTL #2 MTS	63.5	48	33	34	36	38	39	40	40	41	42	43	44	45	45	46	47	48	49	50	51	52
NOTL York MTS	75.5	17	18	18	19	20	21	22	22	23	23	24	24	25	25	26	26	27	27	28	28	29
Port Colborne TS	50.8	37	35	36	36	36	36	36	36	37	37	37	37	37	38	38	38	38	38	39	39	39
Stanley TS	103.6	57	60	61	62	62	63	64	64	65	65	66	67	67	68	69	69	70	71	72	72	73
Thorold TS	91.3	23	24	25	25	25	25	25	26	26	26	26	26	26	27	27	27	27	27	28	28	28
Vansickle TS	99.5	47	52	52	53	53	54	55	56	57	58	59	60	62	63	64	66	67	68	68	68	68
Vineland DS	26.4	20	21	21	21	21	22	23	23	24	25	25	25	25	26	26	26	27	27	27	27	28
Industrial Customer 1	-	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Industrial Customer 2	-	7	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 3	-	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 4	-	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8	8
Industrial Customer 5	-	20	17	17	24	32	35	38	57	57	57	57	57	57	57	57	57	57	57	57	57	57
Industrial Customer 6	-	4	3	2	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Industrial Customer 7	-	24	80	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146	146
Industrial Customer 8[2]	-	-	10	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50

1. Actual summer load adjusted for extreme weather.
2. Curtailable load under specific outage conditions.

APPENDIX D: LIST OF ACRONYMS

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

Appendix 5-F: REG Investment Plan

Welland Hydro
ELECTRIC SYSTEM CORP.
POWERING WELLAND'S FUTURE

Renewable Energy Investment Plan

Per: OEB Chapter 5 Consolidated Distribution Plan Filing Requirements – 5.22 (d)

March 13, 2024

Table of Contents

Executive Summary

Welland Hydro-Electric System Corporation – (WHESC) has developed a Renewable Energy Generation (REG) Investment Plan to provide to the Ontario Energy Board (OEB) and the Independent Electricity System Operator (IESO). The purpose of the plan is to outline WHESC's ability to connect Distributed Generation (DG) systems to its distribution system as well as determine any investments required to accommodate these connections over the next five years.

WHESC currently has 108 MicroFIT, 10 FIT, 1 load displacement, 8 net metering and 2 CHP systems connected to the distribution system, representing a total of 18.2 MW of generation capacity. WHESC forecasts that there will be 61 new connections through to 2029, adding 9.3 MW of combined generation. With the elimination of MicroFIT and FIT programs, customers have shifted their focus to net metering, and DER based projects.

Introduction

In accordance with the OEB's filing requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements, WHESC has prepared the following REG Investment Plan. The REG Investment plan details the readiness of WHESC distribution system to accommodate the connection of renewable energy generation facilities and details any expansion or enhancements necessary to remove grid constraints for the period 2025 to 2029.

WHESC System Overview

WHESC provides local electricity distribution to 25,753 residential and commercial customers, covering a service territory of approximately 81 square kilometers.

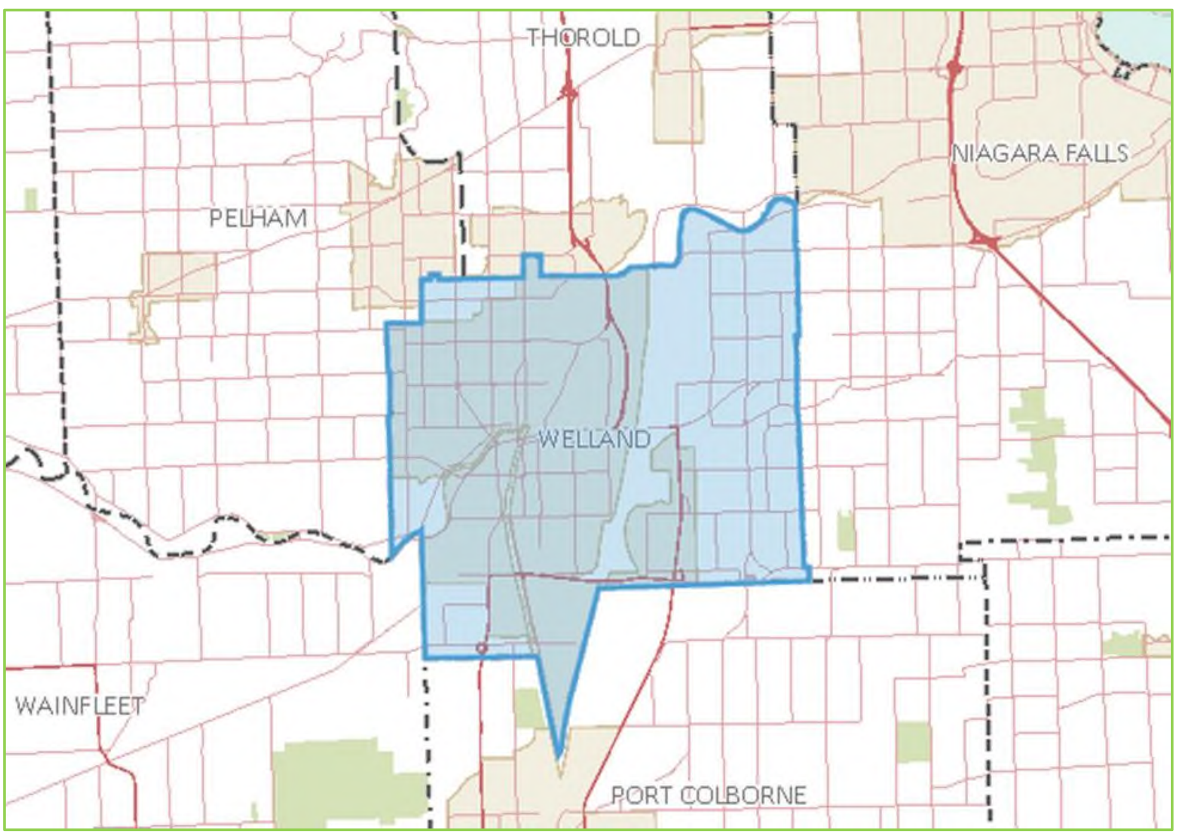

Fig. 1 - WHESC Service Area

WHESC owns, maintains, and operates approximately 337 km of overhead and 160 km of underground primary distribution circuits. WHESC receives power from a single Transformer Station (Crowland TS) which is owned and operated by Hydro One Network Inc. (HONI). The station supplies nine 27.6kV feeder breakers to distribute power throughout the City via WHESC's 27.6 kV distribution system.

Present Capacity for the Connection of Distributed Generation

WHESC has performed an assessment to determine the amount of generation that can be connected to the distribution system. It is imperative that the addition of new generation facilities does not damage distribution equipment or create safety concerns due to short circuit conditions. Equipment must also be rated to meet the thermal capacity requirements of the system at all times, minimize line losses, and to reduce the risk of premature failure. All generation connected to the WHESC system must be equipped with anti-islanding protection schemes, which ensures that generators do not create islanding situations, potentially causing damage to equipment during outages. Large generators operating in parallel with the distribution system are required to install transfer-trip protection schemes per Hydro One's Technical Interconnection Requirements.

Distribution System DG Capacity Assessment

The following table summarizes the available capacity at Crowland TS:

Station	Bus Name	Feeders	Voltage (kV)	SC Cap. (MVA)	Thermal Cap. (MW)	Existing DG (MW)
Crowland TS	QY	M14, M15, M16, M17, M18, M19, M20, M21, M22	27.6	177.6	67.6	18.2 (WHESC only)

Table 1: Summary of DG Capacity at Crowland TS

Present Levels of Distributed Generation Connections

WHESC has connected 129 generators, totaling over 18.2 MW of potential generation to the distribution system which is summarized in Table 2 below:

FIT		MicroFit		Net Metering		CHP		LD		Total	
Count	MW	Count	MW	Count	MW	Count	MW	Count	MW	Count	MW
10	13.15	108	1.06	8	0.09	2	0.07	1	3.8	129	18.2

Table 2: Summary of Existing Connected Generation

Historical Renewable Generation Growth

Between 2008 and 2023, WHESC connected 129 generation projects. The majority of Renewable Generation installations in WHESC's service area consist mainly of rooftop solar PV projects equal to or less than 250kW, however, there is one 10MW solar ground mount generation connection. Table 3 below summarizes the generation connections on WHESC's distribution system between 2008 and 2023.

Year	FIT		MicroFit		Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW	Count	kW
2008	-	-	1	9.4	-	-	-	-	-	-	1	9.4
2009	-	-	-	-	-	-	-	-	-	-	-	-
2010	-	-	1	10.0	-	-	-	-	-	-	1	10.0
2011	-	-	8	71.7	-	-	-	-	-	-	8	71.7
2012	2	350.0	12	100.7	-	-	-	-	-	-	14	450.7
2013	2	500.0	16	170.0	-	-	-	-	-	-	18	670.0
2014	3	11,000.0	11	109.3	1	1.2	-	-	-	-	15	11,110.5
2015	-	-	19	190.0	-	-	-	-	-	-	19	190.0
2016	-	-	14	140.0	-	-	-	-	-	-	14	140.0
2017	-	-	23	230.0	1	5.7	2	73.0	-	-	26	308.7
2018	3	1,300.0	3	30.0	-	-	-	-	-	-	6	1,330.0
2019	-	-	-	-	-	-	-	-	1	3,828.0	1	3,828.0
2020	-	-	-	-	-	-	-	-	-	-	-	-
2021	-	-	-	-	1	10.0	-	-	-	-	1	10.0
2022	-	-	-	-	2	49.7	-	-	-	-	2	49.7
2023	-	-	-	-	3	27.8	-	-	-	-	3	27.8
Total	**10**	**13,150.0**	**108**	**1,061.0**	**8**	**94.3**	**2**	**73.0**	**1**	**3,828.0**	**129**	**18,206.4**

Table 3: Summary of Connected Generation Growth to Date

Projected Renewable Generation Growth

With the elimination of the FIT and MicroFIT programs, WHESC's has observed a decrease in the number of distributed generation projects. Projects have shifted to net metering and load displacement deployments. Based on connection and application activity over the months since the MicroFIT program has ended, WHESC has seen an increase in connection requests related to net metering and load displacement projects. WHESC's forecasted generation connections for 2024 to 2029 is shown in Table 4.

Year	Net Metering		CHP		LD		Total	
	Count	kW	Count	kW	Count	kW	Count	kW
2024	4	20					4	20
2025	7	35			1	6,000	8	6,035
2026	9	45			1	3,000	10	3,045
2027	11	55					11	55
2028	13	65					13	65
2029	15	75					15	75
Total	**59**	**295**	**-**	**-**	**2**	**9,000**	**61**	**9,295**

Table 4: Projected Renewable Generation Growth

Investments to Facilitate Renewable Energy Generation

WHESC is committed to investments related to connecting renewable energy generation if required. WHESC has reviewed the need for capital and OM&A expenditures for the purpose of expanding the distribution system to enable future REG connections. Based on historical trends and anticipated future REG connections, no expenditure is anticipated to be required between 2025 and 2029 for constructing feeder assets to specifically accommodate renewable energy connections.

WHESC will continuously monitor whether additional investments need to take place to enable the connection of REG to the distribution system.

Appendix 5-G: IESO Letter of Comment

IESO response to Welland Hydro-Electric System Corporation REG Investments Plan 2025 – 2029

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On May 29, 2024, Welland Hydro-Electric System Corporation ("WHESC") sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed WHESC's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2025 – 2029.

The IESO notes that WHESC's service territory is within the Niagara region. The Needs Assessment for Niagara was published by Hydro One Networks Inc on May 24, 2021 indicating further regional planning was required for the region.[1] The IESO's Scoping Assessment Outcome Report outlining the planning approach for the region was published on August 24, 2021.[2] The report determined that an Integrated Regional Resource Plan (IRRP) be undertaken for the Niagara region. The IESO's IRRP was published on December 22, 2022.[3] The Niagara region completed its cycle of regional planning with the publication of the Regional Infrastructure Plan (RIP) by Hydro One Networks Inc. in July 2023.[4] WHESC is an active, participating member of the regional planning study team.

On Page 6 of 6 of its Plan, under the heading ***Investments to Facilitate Renewable Energy Generation***, WHESC states that "WHESC has reviewed the need for capital and OM&A expenditures for the purpose of expanding the distribution system to enable future REG connections. Based on historical trends and anticipated future REG connections, no expenditure is anticipated to be required between 2025 and 2029 for constructing feeder assets to specifically accommodate renewable energy connections."

As WHESC has determined it requires no system investments to connect REG over the 2025-2029 Plan period, the IESO submits that no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties.[5]

The IESO appreciates the opportunity provided to review the REG Investments Plan of WHESC and looks forward to working together in further regional planning processes.

1 Hydro One's Need Assessment, May, 2021:
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/niagara/Documents/2021-Niagara-Region_Needs-Assessment.pdf

2 IESO's Scoping Assessment, August, 2021:
https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/Niagara/niagara-20210824-scoping-assessment-outcome-final.pdf

3 IESO's Niagara Integrated Regional Resource Plan, December, 2022:
https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/Niagara/niagara-IRRP-Report.pdf

4 Hydro One's Regional Infrastructure Planning, July, 2023:
https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/niagara/Documents/2023_Niagara_Regional_Infrastructure_Plan-Final-July%20_12_2023.pdf

5 OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10:
https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Appendix 5-H: Asset Condition Assessment (2023)

METSCO

MAKING IT POSSIBLE

ASSET CONDITION ASSESEMENT REPORT 2023

Welland Hydro

P-23-144-IFR 2
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Revision	Date	Authors	Description
R1	2023-11-09	K. Martin-Sturmey, A. Rana, C. Austria, G. Selinger	Revision 1. Updated HI results for Bell Wood Poles.
R0	2023-11-02		Revision 0. Updated HI results for Bell Wood Poles and OH conductors. Updated TUL results for Pole-Mount Reclosers.
IFR 3	2023-10-04		Issued for Review. Updated HI results and asset counts with new data. Extrapolated HI result for Wood Poles.
IFR 2	2023-08-03		Issued for Review
IFR	2023-06-23		Issued for Review

Executive Summary

This Asset Condition Assessment ("ACA") report is prepared for Welland Hydro-Electric System Corporation's ("WHESC") distribution and station assets. METSCO Energy Solutions Inc. ("METSCO") previously developed an Asset Health Index ("AHI") framework for WHESC's assets in August 2018. WHESC engaged METSCO to develop and update their existing AHI. This report provides estimates of assets' conditions based on data provided by WHESC in May through July 2023. The assets classes covered in the report include the following:

Distribution Assets

1. Wood Poles (includes poles owned by Bell)
2. Concrete Poles
3. Pad-Mount & Pole-Trans Transformers
4. Pad-Mount Switchgears
5. Overhead ("OH") Conductors
6. Underground ("UG") Cables
7. SCADA Switches
8. Pole-Mount Reclosers

Substation Assets

1. Power Transformers
2. Air & Vacuum Circuit Breakers
3. Metal-Clad Switchgears
4. Pad-Mount Reclosers

For each asset class, the Health Index is calculated with the provided data. Assets are classified as one of five condition categories: Very Good, Good, Fair, Poor, or Very Poor. The results of the ACA are summarized in Figure E-1.

Table E – 1 presents a numerical summary of the Health Index results. For each asset class the following details are given: the total population, Health Index ("HI") distribution, and the average Data Availability Index ("DAI"). Table E-2 presents the age demographics of each asset class.

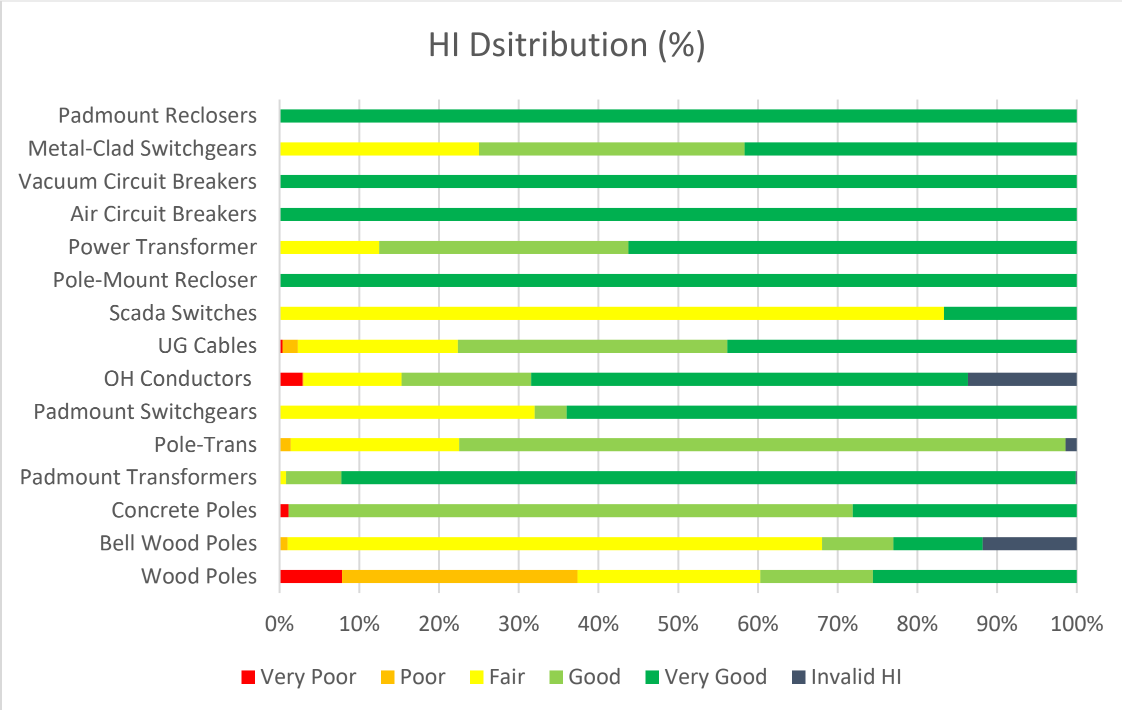

Figure E - 1: Health Index Results

Table E - 1: Numerical Summary of ACA Results

Asset Category	Population	HI Distribution						DAI
		Very Poor	Poor	Fair	Good	Very Good	Invalid HI	
Distribution Assets								
*Wood Poles**	7527	591	2223	1724	1065	1924	0**	73%
Bell Wood Poles	795	0	8	533	71	89	94	95%
Concrete Poles	89	1	0	0	63	25	0	100%
Pad-Mount Transformers	853	0	0	7	59	786	1	100%
Pole-Trans	71	0	1	15	54	0	1	99%
Pad-Mount Switchgears	25	0	0	8	1	16	0	100%
OH Conductors (m)	498,641	14,542	544	61,296	80,894	273,172	68,194	96%
UG Cables (m)	161,319	622	3,082	32,397	54,471	70,647	100	100%
SCADA Switches	18	0	0	15	0	3	0	100%
Pole-Mount Reclosers	11	0	0	0	0	11	0	100%
Station Assets								
Power Transformers	16	0	0	2	5	9	0	100%

Asset Category	Population	HI Distribution						DAI
		Very Poor	Poor	Fair	Good	Very Good	Invalid HI	
Air Circuit Breakers	8	0	0	0	0	8	0	100%
Vacuum Circuit Breakers	25	0	0	0	0	25	0	100%
Metal-Clad Switchgears	12	0	0	3	4	5	0	100%
Pad-Mount Reclosers	14	0	0	0	0	14	0	100%

***Note:** HI results for this asset class were extrapolated.

****Note:** 4789 wood poles had invalid HI and were extrapolated across asset the demographic.

Table E - 2: Numerical Summary of Asset Demographics

Asset Category	Population	Age Distribution					
		0 – 10 Years	11– 20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
Wood Poles	7527	1342	938	1164	466	3591	26
Bell Wood Poles	795	43	20	35	62	609	26
Concrete Poles	89	0	5	2	18	64	0
Pad-Mount Transformers	853	336	202	173	101	41	0
Pole-Trans	71	0	0	0	8	63	0
Pad-Mount Switchgears	25	13	4	8	0	0	0
OH Conductors	498,641	87,444	69,536	94,085	26,264	198,434	22,879
UG Cables	161,319	59,640	39,224	35,341	15,978	11,036	100
SCADA Switches	18	0	3	15	0	0	0
Pole-Mount Reclosers	11	0	0	0	0	11	0
Power Transformers	14	8	3	2	1	0	0
Air Circuit Breakers	8	0	0	0	0	8	0
Vacuum Circuit Breakers	25	4	5	16	0	0	0
Metal-Clad Switchgears	12	1	3	5	0	3	0
Pad-Mount Reclosers	14	12	2	0	0	0	0

Table of Contents

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List of Acronyms

The following acronyms are used within the Asset Condition Assessment report:

Acronym	Definition
ACA	Asset Condition Assessment
AHI	Asset Health Index
AM	Asset Management
DAI	Data Availability Index
DGA	Dissolved Gas Analysis
EOL	End-of-Life
HI	Health Index
IR	Infrared
ISO	International Organization for Standardization
LV	Low Voltage
METSCO	METSCO Energy Solutions Inc.
OH	Overhead
OQ	Oil Quality
PF	Power Factor
RS	Remaining Strength
SAMP	Strategic Asset Management Plan
SCADA	Supervisory Control and Data Acquisition
TUL	Typical Useful Life
UG	Underground
WHESC	Welland Hydro-Electric System Corporation

1 Introduction

This report summarizes the results of an Asset Condition Assessment ("ACA") study carried out by METSCO Energy Solutions Inc. ("METSCO") on behalf of Welland Hydro-Electric System Corporation's ("WHESC"). METSCO is an industry expert in ACA and Asset Management ("AM") practices, with extensive experience conducting ACAs, developing AM plans, and implementing AM frameworks for transmission and distribution utilities across North America. METSCO's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions.

1.1 Purpose and Scope

WHESC engaged METSCO to update and develop their existing Asset Health Index ("AHI") formulations and conduct an ACA on their distribution and substation assets to improve awareness of system health demographics.

The ACA methodology comprising this study assessed multiple categories of assets within WHESC's system. Adoption of the ACA methodology would require periodic asset inspections and recording of their condition to identify those most at risk. Additionally, computing the HI for substation assets requires identifying End-of-Life ("EOL") criteria for various components associated with each asset type. Each criterion represents a factor that is influential in determining the component's current condition relative to conditions reflective of potential failure. These components and tests shown in the tables are weighted based on their importance in determining a given asset's EOL. The assets classes covered in the report include the following:

Distribution Assets

1. Wood Poles (includes poles owned by Bell Canada)
2. Concrete Poles
3. Pad-Mount Transformers
4. Pole-Trans
5. Pad-Mount Switchgears
6. Overhead ("OH") Conductors
7. Underground ("UG") Cables
8. SCADA Switches
9. Pole-Mount Reclosers

Substation Assets

1. Power Transformers
2. Air & Vacuum Circuit Breakers
3. Metal-Clad Switchgears
4. Pad-Mount Reclosers

2 Context of the ACA Within AM Planning

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing 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 is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the International Organization for Standardization ("ISO") standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM 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 AM 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 a value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. The ACA is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to

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

realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.1

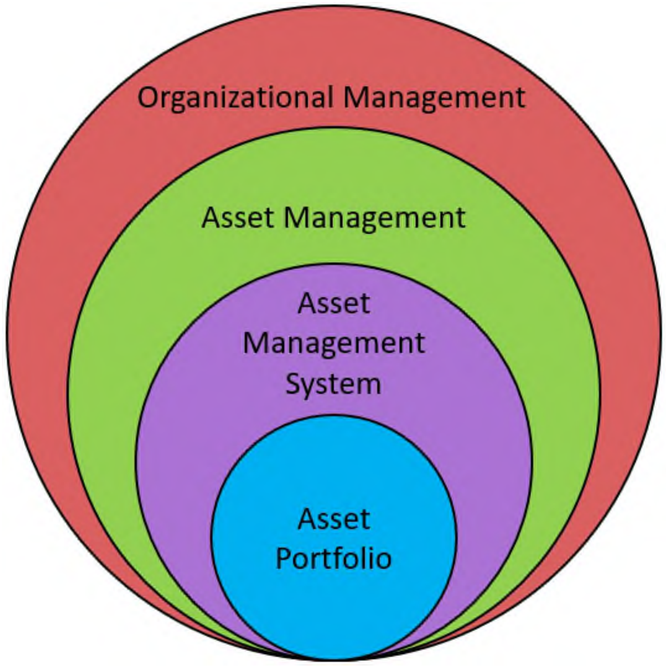

Figure 2-1: Relationship Between Key AM Terms[1]

2.2 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:

- Collection and storage of technical specifications;
- Historical asset performance;
- Projected asset behaviour and degradation;
- Configuration of an asset or asset-group within the system; and
- Operational relationship of one asset to another.

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

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

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 best AM practices 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 acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented. 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.

2.3 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: increased public and worker safety, realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated compliance among the asset base, and corporate sustainability.

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

AM 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. Continually improved asset data and data collection procedures updated Strategic Asset Management Plans (“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.

3 Asset Condition Assessment Methodology

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 individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;

1. *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;

2. *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

3. *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.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO used an additive approach when conducting the ACA for all station assets, which is in alignment with other utilities in Ontario.

3.1 Overview of Selected ACA Methodology

To calculate the HI for the asset classes, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of each asset class. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1 exemplifies an HI formulation table.

Condition parameters of the asset classes are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded for each asset class.

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

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 numerical grade of 4 represents the best condition indicator, whereas a grade of 0 represents the worst condition.

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

3.1.1 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.

3.1.2 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 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 those 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 maintaining, refurbishing, or replacing the asset prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging 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

3.2 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 Data Availability Index ("DAI"): a measure of the availability of the condition parameter data 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 to 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 a is the availability of coefficient (a =1 when data are available and a =0 when data are 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's condition with a high degree of confidence. For an individual asset, the HI was not calculated if the DAI fell below 70%. The average DAI for each asset class is summarized in Table 3-2 below.

Table 3-2: Average DAI by Asset Class

Asset Class	Average DAI
Wood Poles	73%
Bell Wood Poles	95%
Concrete Poles	100%
Pad-Mount Transformers	100%
Pole-Trans	99%
Pad-Mount Switch Gears	100%
Overhead Primary Conductors	96%
Underground Primary Cables	99%
SCADA Switches	100%
Pole-Mount Reclosers	100%
Power Transformers	100%
Air Circuit Breakers	100%
Vacuum Circuit Breakers	100%
Metal-Clad Switchgears	100%
Pad-Mount Reclosers	100%

4 Asset Condition Assessment Results

This section presents the current HIF for each asset class, the calculated HI scores, TUL results, and reviews the data available to perform the study. Figure 4-1 and Table 4-1 summarize the HI Results for each asset class in the ACA study. Table 4-2 shows the age demographics of each asset class.

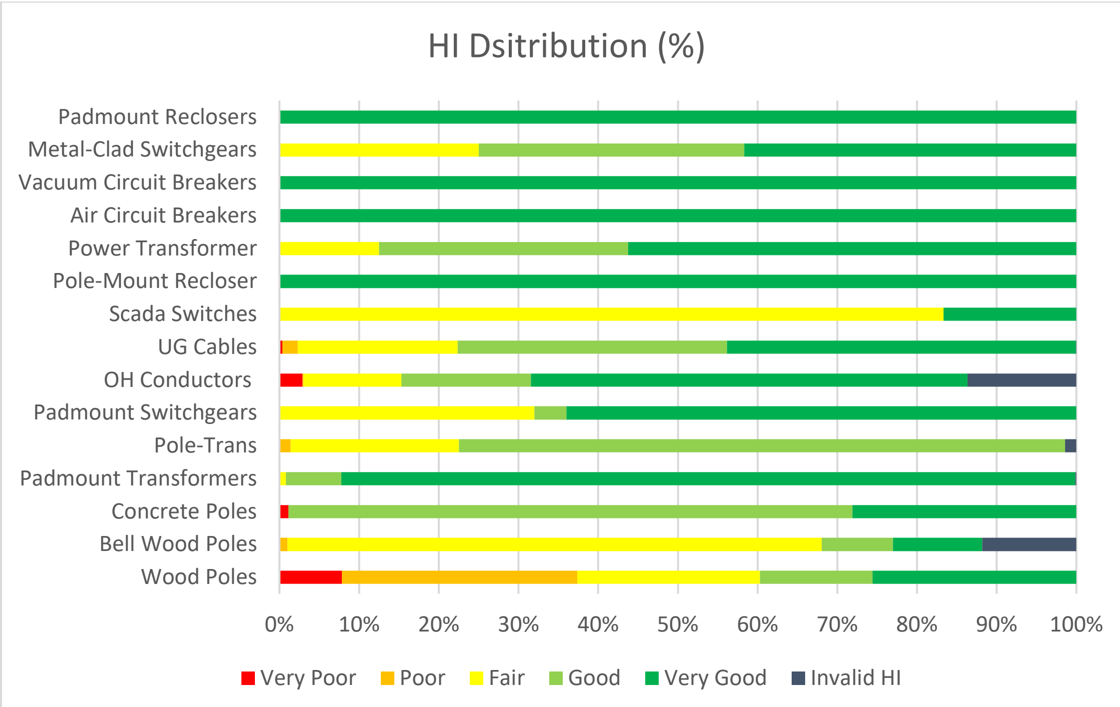

Figure 4-1: HI Index Results

Table 4-1: Numerical Summary of ACA Results

Asset Category	Population	HI Distribution						DAI
		Very Poor	Poor	Fair	Good	Very Good	Invalid HI	
Distribution Assets								
*Wood Poles**	7527	591	2223	1724	1065	1924	0**	73%
Bell Wood Poles	795	0	8	533	71	89	94	95%
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Pad-Mount Transformers	853	0	0	7	59	786	1	100%
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Pad-Mount Switchgears	25	0	0	8	1	16	0	100%
OH Conductors (m)	498,641	14,542	544	61,296	80,894	273,172	68,194	96%
UG Cables (m)	161,319	622	3,082	32,397	54,471	70,647	100	100%

Asset Category	Population	HI Distribution						DAI
		Very Poor	Poor	Fair	Good	Very Good	Invalid HI	
SCADA Switches	18	0	0	15	0	3	0	100%
Pole-Mount Reclosers	11	0	0	0	0	11	0	100%
Station Assets								
Power Transformers	16	0	0	2	5	9	0	100%
Air Circuit Breakers	8	0	0	0	0	8	0	100%
Vacuum Circuit Breakers	25	0	0	0	0	25	0	100%
Metal-Clad Switchgears	12	0	0	3	4	5	0	100%
Pad-Mount Reclosers	14	0	0	0	0	14	0	100%

***Note:** HI results for asset class were extrapolated.

****Note:** 4789 wood poles had invalid HI and were extrapolated across the asset demographic.

Table 4-2: Asset Age Demographics

Asset Category	Population	Age Distribution					
		0 – 10 Years	11– 20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
Wood Poles	7527	1342	938	1164	466	3591	26
Bell Wood Poles	795	43	20	35	62	609	26
Concrete Poles	89	0	5	2	18	64	0
Pad-Mount Transformers	853	336	202	173	101	41	0
Pole-Trans	71	0	0	0	8	63	0
Pad-Mount Switchgears	25	13	4	8	0	0	0
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SCADA Switches	18	0	3	15	0	0	0
Pole-Mount Reclosers	11	11	0	0	0	0	0
Power Transformers	14	8	3	2	1	0	0
Air Circuit Breakers	8	0	0	0	0	8	0
Vacuum Circuit Breakers	25	4	5	16	0	0	0

Asset Category	Population	Age Distribution					
		0 – 10 Years	11– 20 Years	21-30 Years	31-40 Years	40+ Years	Unknown
Metal-Clad Switchgears	12	1	3	5	0	3	0
Pad-Mount Reclosers	14	12	2	0	0	0	0

4.1 Distribution Assets

4.1.1 Wood Poles

HI Formulation

Wood poles are an integral part of the distribution system. Poles are the support structure for OH distribution lines as well as assets such as OH transformers, and switches.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation processes for wood poles involve biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather which can impact the mechanical strength of the pole. Loss in the strength of the pole can present additional safety and environmental risks to the public and the utility. In the short term (one to three years), the most informative end-of-life criterion is the calculation of remaining strength through pole testing. However, since pole strength tends to fall off quickly as a pole starts to degrade, the preferred predictor over the medium to long term (three to ten years) is age. A pole that is not yet showing effects of age but exhibits other defects such as large cracks or rot may also be targeted for replacement.

The HI for wood poles is calculated based on EOL criteria is summarized in Table 4-3 and Table 4-5.

Table 4-3: Wood Poles HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Pole Test Results	12	A,B,C,D,E	4,3,2,1,0	48
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Pole Top Feathering	4	A,C,E	4,2,0	16
Woodpecker Damage	1	A,C,E	4,2,0	4
Insect Damage	1	A,C,E	4,2,0	4
Cracks	1	A,C,E	4,2,0	4
Fire Damage	1	A,C,E	4,2,0	4
Pole Lean	1	A,E	4,0	4
Total Score				**116**

Table 4-4: Bell-Owned Wood Poles HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	8	A,B,C,D,E	4,3,2,1,0	32
Pole Top Feathering	3	A,C,E	4,3,2,1,0	12
Woodpecker Damage	1	A,C,E	4,3,2,1,0	4
Insect Damage	1	A,C,E	4,3,2,1,0	4
Cracks	1	A,C,E	4,3,2,1,0	4
Fire Damage	1	A,C,E	4,3,2,1,0	4
Pole Lean	1	A,E	4,0	4
Total Score				**64**

Data Collection and Assumptions

The HI for wood poles was calculated using asset data and inspection results provided by WHESC. Inspection data provided by WHESC was conducted between 2019-2023. Starting in 2022 WHESC began using Polux testing for their wood poles, which provides a quantitative measure for a wood pole's remaining strength ("RS"). Polux Testing was provided for 2864 of WHESC's wood poles. The average DAI for wood poles owned by WHESC is 73%. Additional data was provided for wood poles owned by Bell Canada. The average DAI for wood poles owned by Bell Canada is 95%.

Results – WHESC Wood Poles

WHESC owns 7,527 wood poles across its service area. To overcome the gap in Polux data, HI results were calculated for Polux tested wood poles, which produced valid HI results for 2,738 wood poles. The HI for wood poles was then extrapolated for the remaining assets using ten-year age bands. The HI distribution for WHESC-owned wood poles can be seen in Figure 4-2.

TUL results for WHESC-owned wood poles can be seen in Figure 4-3, which shows that approximately 3,340 wood poles are Past TUL. The TUL for wood poles is 45 years. Wood poles within 15 years of TUL were classified as Approaching TUL.

Results – Bell Wood Poles

Bell Canada owns 795 wood poles and valid HI results were calculated for 701 wood poles. The HI distribution for Bell Canada's wood poles can be seen in Figure 4-4, which shows 0 wood poles are in Very Poor condition.

TUL results for Bell Canada owned wood poles can be seen in Figure 4-5, which shows that 579 wood poles are Past TUL. The TUL for wood poles is 45 years. Wood poles within 15 years of TUL were classified as Approaching TUL.

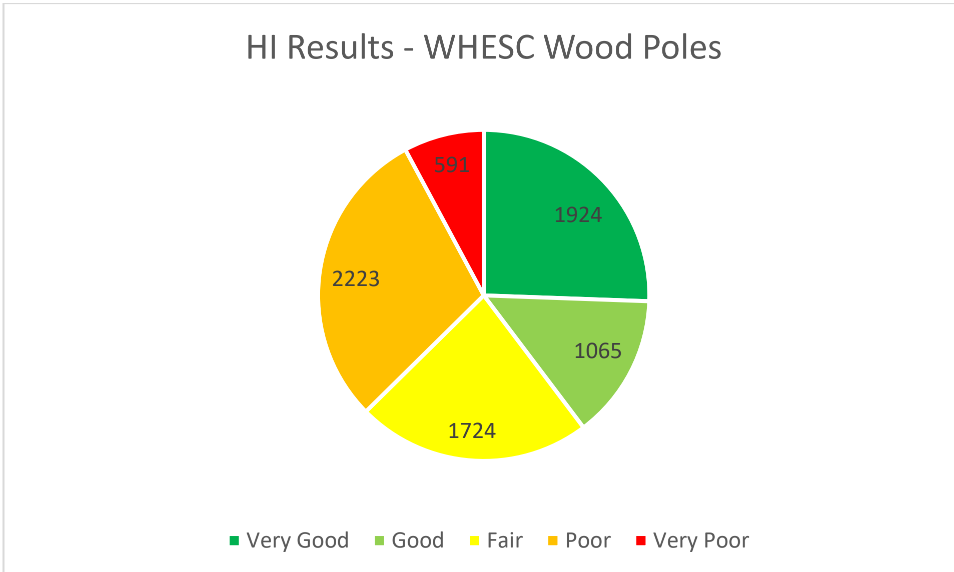
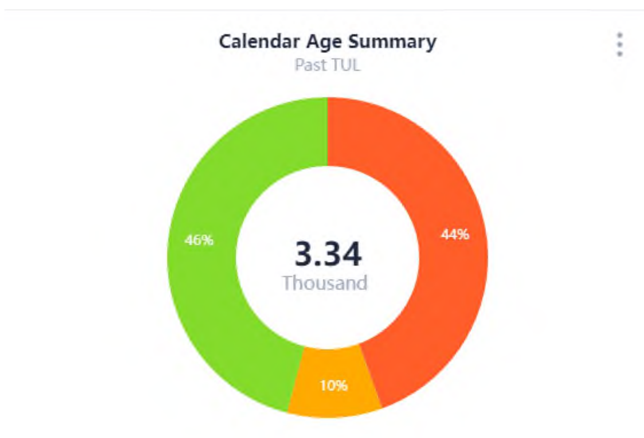


Figure 4-2: WHESC Wood Poles HI Results



Past TUL	3.34K
Approaching TUL	720
Not Near TUL	3.44K
Total	7.50K

Figure 4-3: WHESC Wood Poles Demographic Results

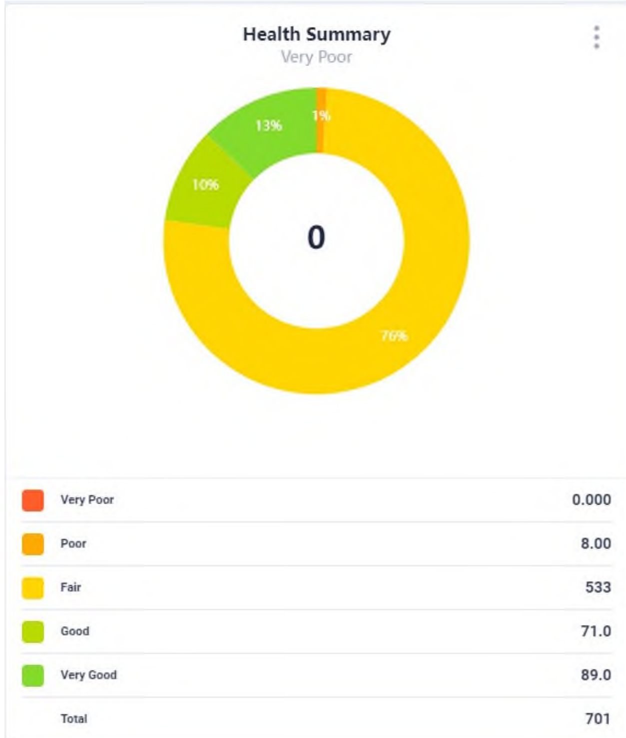


Figure 4-4: Bell Canada owned Wood Poles HI Results

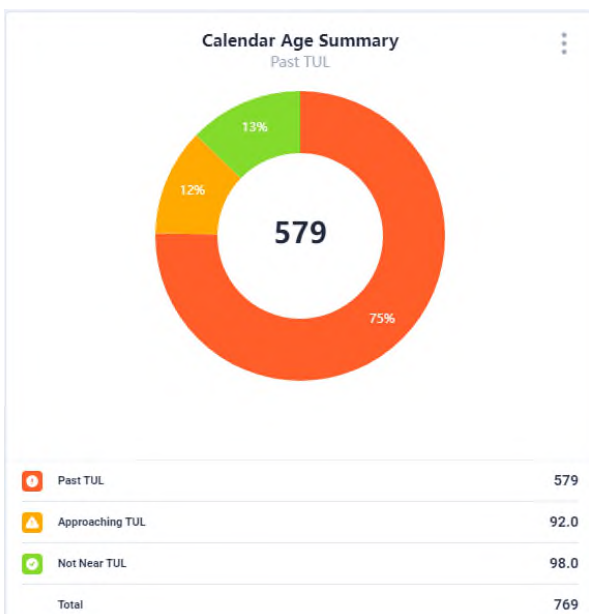


Figure 4-5: Bell Canada owned Wood Poles Demographic Results

4.1.2 Concrete Poles

HI Formulation

Concrete poles develop corrosion on the internal reinforcing bars, which expands the iron and displaces the concrete in a process known as spalling. Once spalling begins, poles become weaker and tend to fail over a short number of years. There are limited methods for the long-term repair of a spalled pole. Spalling is accelerated in the presence of road salt. In the short term (one to three years) the most informative indicator is a visual observation of spalling; there is no way to predict that corrosion is occurring inside concrete poles. The best predictor of a need for medium-term replacement (three to ten years) is the age and condition of similar poles.

The HI for concrete poles is calculated based on EOL criteria summarized in Table 4-5.

Table 4-5: Concrete Poles HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Pole Lean	3	A,E	4,0	12
Total Score				**20**

Data Collection and Assumptions

The HI for concrete poles was calculated using asset data and inspection results provided by WHESC. Inspection data provided by WHESC was conducted in 2023. The average DAI for WHESC's concrete poles is 100%.

Results

WHESC owns 89 concrete poles and valid HI results were calculated for all concrete poles. The HI distribution for WHESC's concrete poles can be seen in Figure 4-6, which shows that 1 concrete pole is in Very Poor condition.

TUL results for concrete poles can be seen in Figure 4-7, which shows that 1 concrete pole is Past TUL. The TUL for wood poles is 60 years. Concrete poles within 20 years of TUL were classified as Approaching TUL.

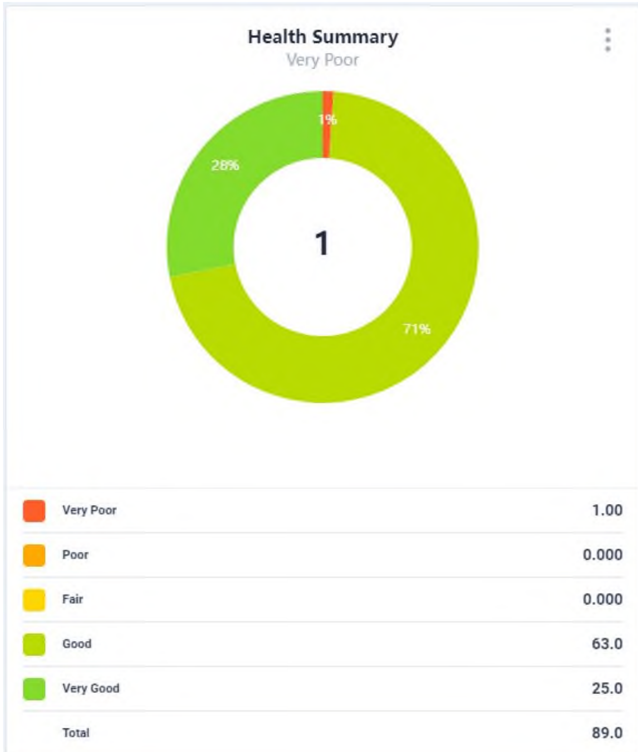


Figure 4-6: Concrete Pole HI Results

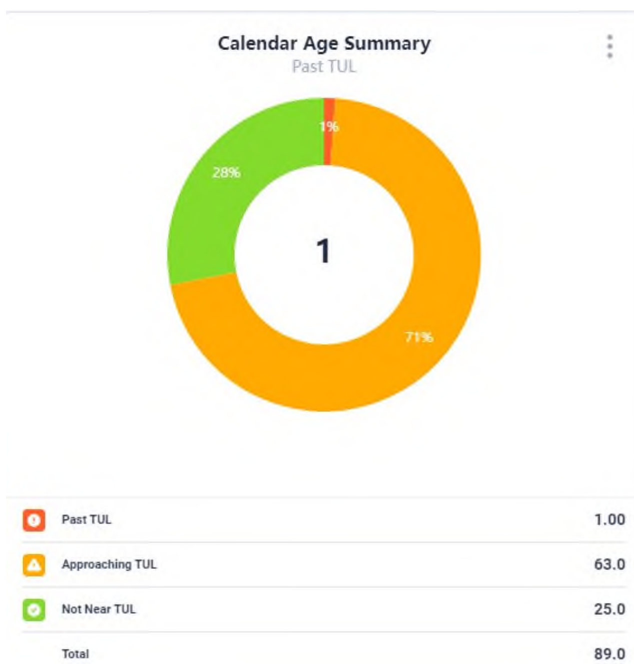


Figure 4-7: Concrete Poles Demographic Results

4.1.3 Pad-Mount & Pole-Trans Transformers

HI Formulation

Transformers are another large asset class within the distribution system. This asset category is made up of a large number of units, each with a modest replacement value.

Distribution transformers typically reach their EOL due to physical tank deterioration, such as corrosion which, in extreme cases, can lead to oil leaks. Where corrosion is detected, a distribution transformer may be cycled back to the shop, re-painted, and gaskets can be replaced. Other modes of failure include overheated connections due to loosened connectors which are typically detected in infrared scanning and tightened. Sometimes the deterioration of civil infrastructures such as pads and duct banks contribute to the decision to replace a pad-mount transformer. Occasionally, a distribution transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified.

Distribution transformers convert power as single-phase or three-phase units and are typically a run-to-failure asset, although transformers may be renewed as part of a planned program. Apart from painting the tanks, replacing damaged bushings, or repairing leaky gaskets, most utilities carry out very little preventative maintenance or testing on distribution transformers. Utilities generally replace pad-mount transformers during underground rebuild projects or when increases in load patterns develop. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified.

The HI for pad-mount transformers is calculated based on EOL criteria summarized in Table 4-6. The HI for pole-trans is calculated based on the EOL criteria summarized in Table 4-7.

Table 4-6: Pad-Mount Transformers HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	12	A,B,C,D,E	4,3,2,1,0	48
IR Scan	8	A,B,C,D,E	4,3,2,1,0	32
Oil Leaks	5	A,E	4,0	20
Corrosion	4	A,E	4,0	16
Condition of Pad	4	A,E	4,0	16
Condition of Enclosure	3	A,E	4,0	12
Condition of Terminations	2	A,E	4,0	8
Overall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**160**

Table 4-7: Pole-Trans HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	12	A,B,C,D,E	4,3,2,1,0	48
Non-Discretionary Obsolescence	10	A,E	4,0	40
IR Scan	8	A,B,C,D,E	4,3,2,1,0	28
Oil Leaks	5	A,E	4,0	20
Corrosion	4	A,E	4,0	16
Structural Condition	4	A,E	4,0	16
Condition of Terminations	2	A,E	4,0	8
Overall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**188**

Data Collection and Assumptions

The HI for distribution transformers was calculated using asset data, inspection results, and IR reports provided by WHESC. Inspection data provided by WHESC was collected between 2021-2022. The average DAI for WHESC's pad-mount transformers is equivalently 100% (99.95%). The average DAI for WHESC's pole-trans units are 99%.

Results – Pad-Mount Transformers

WHESC owns 853 pad-mount transformers and valid HI results were calculated for 852 pad-mount transformers. The HI distribution for WHESC's pad-mount transformers can be seen in Figure 4-8, which shows that 0 pad-mount transformers are in Very Poor condition.

TUL results for pad-mount transformers can be seen in Figure 4-9, which shows that 41 pad-mount transformers are Past TUL. The TUL for distribution transformers is 40 years. Distribution transformers within 13 years of TUL were classified as Approaching TUL.

Results – Pole-Trans

WHESC owns 71 pole-trans units and valid HI results were calculated for 70 pole-trans units. The HI distribution for WHESC's pole-trans can be seen in Figure 4-10, which shows that 0 pole-trans units are in Very Poor condition.

TUL results for pole-trans units can be seen in Figure 4-11, which shows that 63 pole-trans Past TUL. The TUL for distribution transformers is 40 years. Distribution transformers within 13 years of TUL were classified as Approaching TUL.

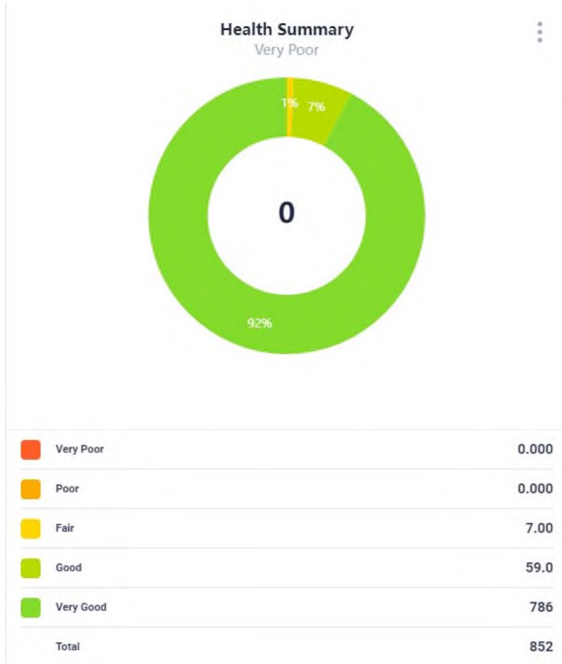


Figure 4-8: Pad-mount Transformers HI Results

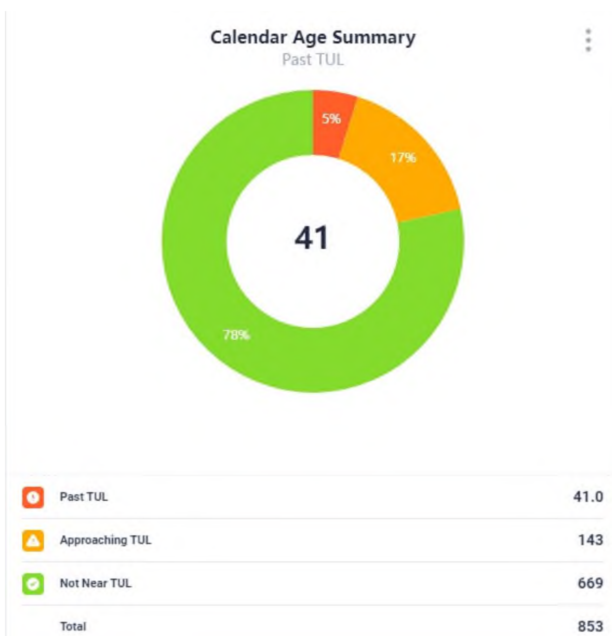


Figure 4-9: Pad-mount Transformers Demographic Results

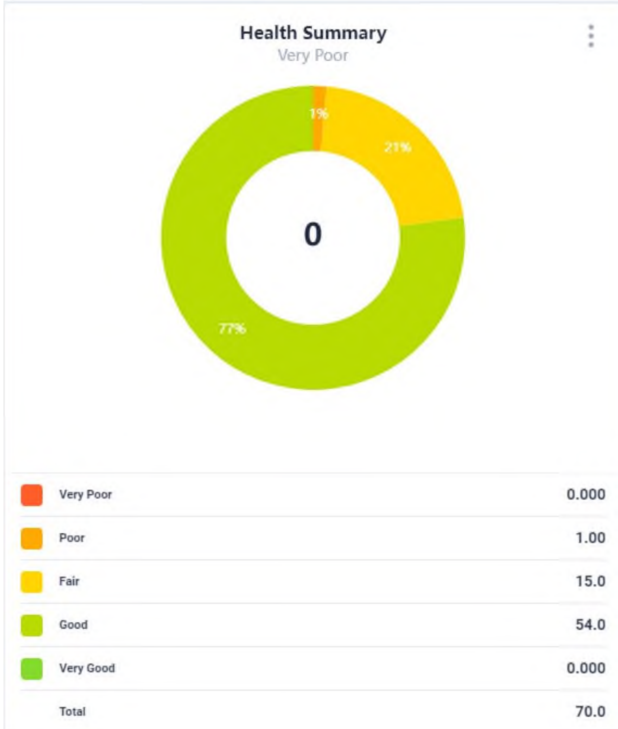


Figure 4-10: Pole-Trans HI Results

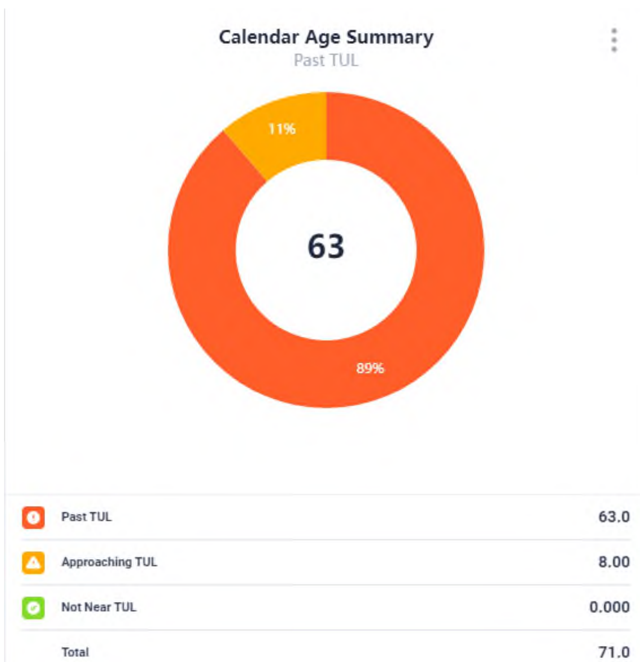


Figure 4-11: Pole-Trans Demographic Results

4.1.4 Pad-Mount Switchgears

HI Formulation

Typical EOL indicators for pad-mount switchgears are related to physical deterioration of the enclosure, the internal workings of the switchgear, and in some cases the extent of deterioration to the concrete pad. Preventative maintenance options for switchgear may include the replacement of components such as interphase barriers, and high-pressure cleaning.

The HI for pad-mount switchgears is calculated based on EOL criteria summarized in Table 4-8.

Table 4-8: Pad-mount Switchgear HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
IR Scan	8	A,B,C,D,E	4,3,2,1,0	32
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Condition of Pad	4	A,E	4,0	16
Condition of Enclosure	3	A,E	4,0	12
Condition of Terminations	2	A,E	4,0	8
Condition of Blades	2	A,E	4,0	8
Condition of Operating Mechanism	2	A,E	4,0	8
Overall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**108**

Data Collection and Assumptions

The HI for pad-mount switchgears was calculated using asset data, inspection results, and IR reports provided by WHESC. Inspection data provided by WHESC was conducted in 2022. The average DAI for WHESC's pad-mount switchgears is 100%.

Results

WHESC owns 25 pad-mount switchgears within its service area. Valid HI results were calculated for all assets. The HI distribution for WHESC's pad-mount switchgears can be seen in Figure 4-12, which shows that 0 pad-mount switchgears are in Very Poor condition. All assets are in Fair condition or better.

TUL Results for pad-mount switchgears can be seen in Figure 4-13, which shows that 0 pad-mount switchgears are past TUL. The TUL for pad-mount switchgears is 30 years. Pad-mount switchgears within 10 years of TUL were classified as Approaching TUL.

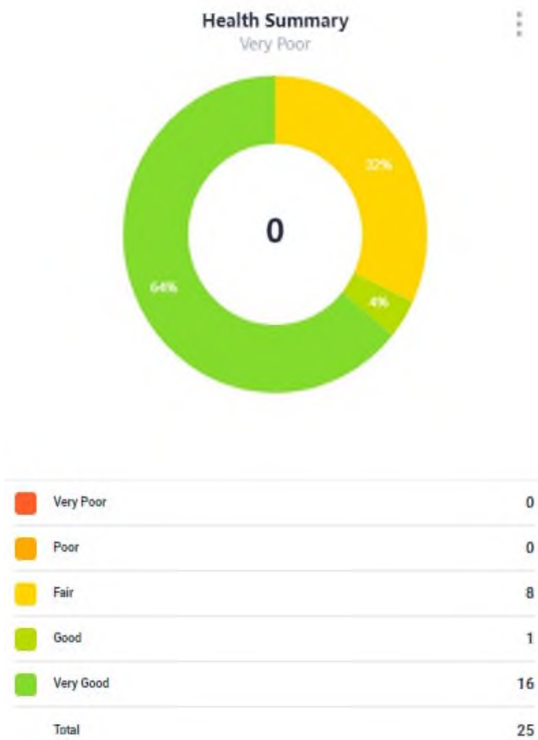


Figure 4-12: Pad-Mount Switchgear HI Results

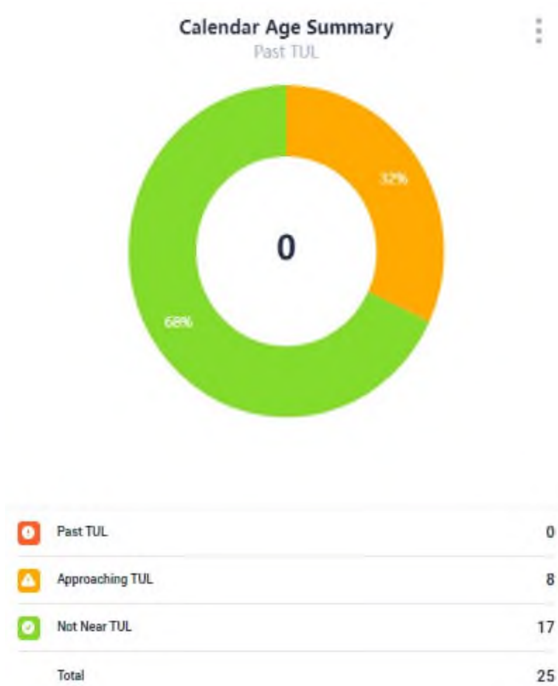


Figure 4-13: Pad-Mount Switchgears Demographic Results

4.1.5 Overhead Conductors

HI Formulation

OH conductors tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons. It is very rare that the conductor condition would drive a distinct replacement investment program. There is one recognized conductor risk, namely the tendency for small copper conductors to age at an accelerated rate and become brittle.

Although laboratory tests exist to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for estimating the tensile strength of conductors and estimating the remaining life of an asset is the use of service age.

The HI for OH primary conductors is calculated based on EOL criteria summarized in Table 4-9.

Table 4-9: OH Conductors HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Small Conductor Risk	1	A,E	4,0	4
Total Score				**8**

Data Collection and Assumptions

The HI for OH conductors was calculated using asset data provided by WHESC. The average DAI for WHESC's OH conductors is 96%.

Results

WHESC owns approximately 498.6 km of OH conductors across its service area. Valid HI results were calculated for 430.4 km of OH conductors. The HI distribution for WHESC's OH conductors can be seen in Figure 4-14, which shows 14.5 km of OH conductors are in Very Poor condition.

TUL results for OH conductors can be seen in Figure 4-15, which shows 89.2 km of OH conductors are Past TUL. The TUL for OH conductors is 60 years. OH conductors within 20 years of TUL were classified as Approaching TUL.

Figure 4-14: OH Conductors HI Results

Figure 4-15: OH Conductors Demographic Results

4.1.6 Underground Cables

HI Formulation

Distribution UG primary cables are one of the more challenging assets in electricity systems from a condition assessment viewpoint. Although several test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring cable failure rates and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, cables are replaced 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.

Service age provides a reasonably good measure of the remaining life of cables with the lack of visual inspection for cable defects. As a minimum, age-based parameters and the knowledge of past failure instances will allow the comparison of a given cable segment to other cables of similar vintage. An additional parameter that can be considered is that any cable sections that have previously experienced a fault are considered a higher risk for recurrence although the data on this topic requires further research.

The HI for UG primary cables is calculated based on EOL criteria summarized in Table 4-10.

Table 4-10: UG Cables HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Cable Splice	1	A,E	4,0	4
Feeder Failure History	1	A,B,C,D,E	4,3,2,1,0	4
Total Score				**16**

Data Collection and Assumptions

The HI for UG cables was calculated using asset data and fault reports provided by WHESC. Fault reports provided by WHESC were conducted from 2018-2022. UG cable segments with faults were also identified by WHESC. The average DAI for UG cables is equivalently 100% (99.8%).

Results

WHESC owns 161.3 km of primary UG cables across its service area. Valid HI results were calculated for 161.2 km of UG cables. The HI distribution for WHESC's UG cables can be seen in Figure 4-16, which shows 0.6 km of UG cables are in Very Poor condition. TUL results for UG cables approaching their TUL are shown in

Figure 4-17, which shows 27 km of UG cables are Past TUL. The TUL for UG cables is 30 years. UG cables within 10 years of TUL were classified as Approaching TUL.

Figure 4-16: UG Cables HI Results

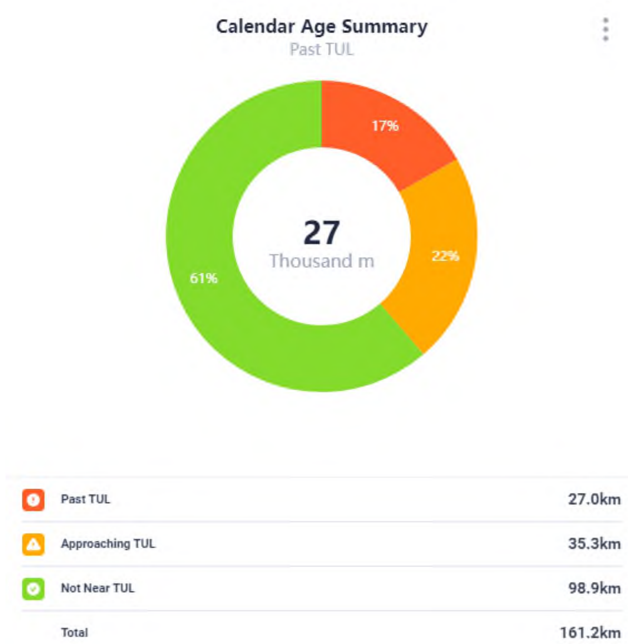


Figure 4-17: UG Cables Demographic Results

4.1.7 SCADA Switches & Pole-Mount Reclosers

HI Formulation

This asset class includes switches which are controlled via SCADA. Smart switches experience similar degradation mechanisms to OH switches and use a similar HI formulation. The primary means of inspecting and maintaining switches are to visually identify dirt and corrosion and to use IR scans to find "hot" connections. The Health Index for SCADA switches is calculated by considering a combination of service age and infrared scan results.

The HI for SCADA switches & Pole-Mount Reclosers are calculated based on EOL criteria summarized in Table 4-11.

Table 4-11: SCADA Switches & Pole-mount Reclosers HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
IR Scan	1	A,C,E	4,3,2,1,0	4
Total Score				**8**

Data Collection and Assumptions

The HI for SCADA switches & pole-mount reclosers was calculated using asset data and IR reports provided by WHESC. Since both SCADA switches and pole-mount reclosers were not present in the OH IR reports provided by WHESC, METSCO assumed all assets showed no signs of hotspots. The average DAI for SCADA switches and pole-mount reclosers is 100%.

Results – SCADA Switches

WHESC owns 18 SCADA switches and valid HI results were calculated for all SCADA switches. The HI distribution for SCADA switches is shown in Figure 4-18, which shows that 0 SCADA switches are in Very Poor condition. TUL results for SCADA switches can be seen in Figure 4-19, which shows 15 SCADA switches are Past TUL. The TUL for SCADA switches is 20 years. SCADA switches within 7 years of TUL are considered to be Approaching TUL.

Results – Pole-Mount Reclosers

WHESC owns 11 pole-mount reclosers and valid HI results were calculated for all reclosers. The HI distribution for pole-mount reclosers is shown in Figure 4-20, which shows that 0 pole-mounted are in Very Poor condition. TUL results for pole-mount reclosers can be seen in Figure 4-21, which shows 0 pole-mount reclosers are Past TUL. The TUL for pole-mount reclosers is 20 years. Reclosers within 7 years of TUL are considered to be Approaching TUL. It should be noted that WHESC's oldest pole-mount recloser is 6 years old.

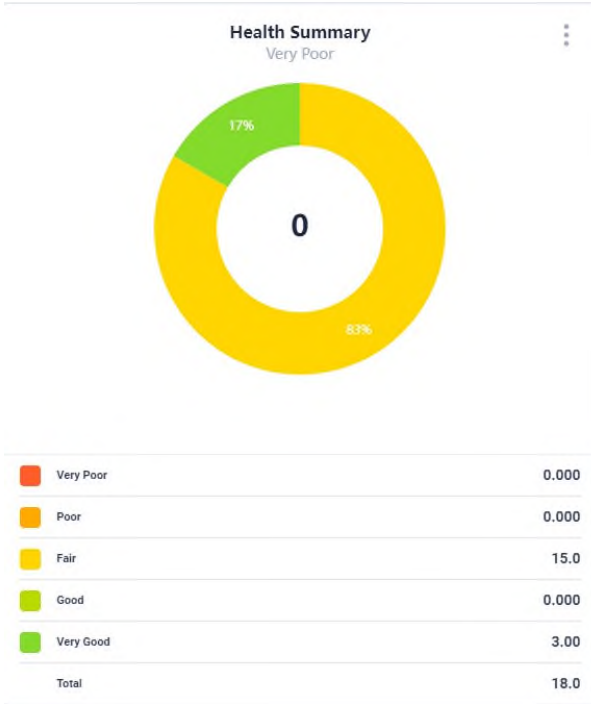


Figure 4-18: SCADA Switches HI Results

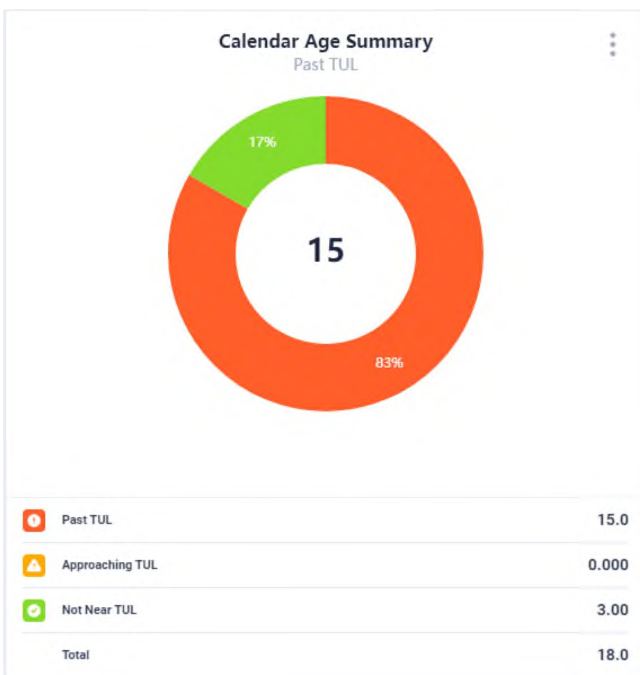


Figure 4-19: SCADA Switches Demographic Results

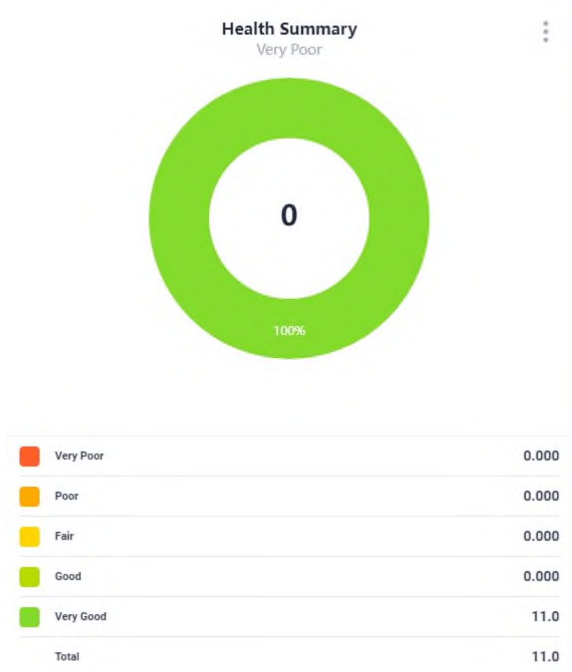


Figure 4-20: Pole-Mount Reclosers HI Results

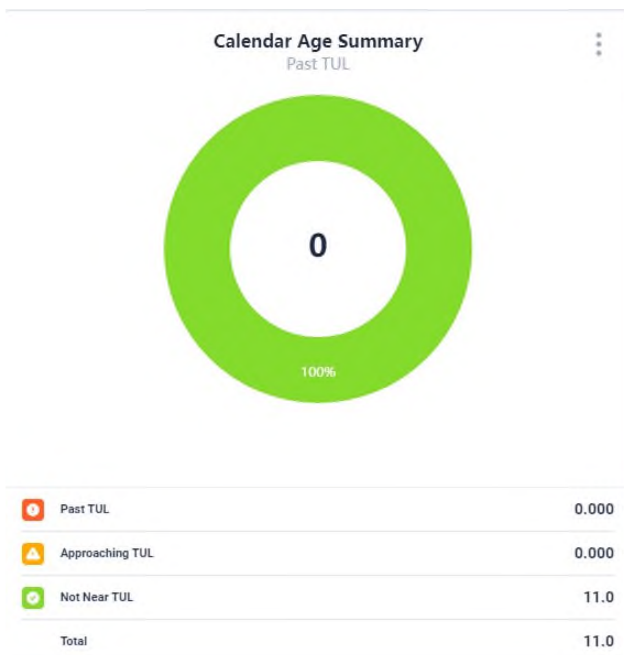


Figure 4-21: Pole-Mount Reclosers Demographic Results

4.2 Station Assets

The HI and demographic results are summarized by station in Table 4-12 and Table 4-13, respectively.

Table 4-12: Station HI Summary

Station	PTX 1	PTX 2	Circuit Breakers	4.16 kV Metal-Clad SWGR	27.6 kV Metal-Clad SWGR	Pad-Mount Reclosers	Average DAI
MS 1	63%	N/A	88%	82%	89%	N/A	100%
MS 2	83%	N/A	N/A	N/A	N/A	93%	100%
MS 3	100%	93%	N/A	N/A	N/A	100%	100%
MS 4	86%	N/A	96%	89%	57%	N/A	100%
MS 5	87%	88%	96%	82%	50%	N/A	100%
MS 6	73%	N/A	94%	80%	N/A	N/A	100%
MS 7	85%	N/A	100%	100%	68%	N/A	100%
MS 8	93%	N/A	N/A	N/A	N/A	100%	100%
MS 9	93%	N/A	N/A	N/A	N/A	100%	100%
MS 10	83%	N/A	86%	75%	95%	N/A	100%
MS 11	95%	N/A	N/A	N/A	N/A	100%	100%
MS 12	73%	60%	88%	89%	N/A	N/A	100%
MS 14	74%	N/A	N/A	N/A	N/A	100%	100%

Table 4-13: Station Age Summary

Station	PTX 1	PTX 2	Circuit Breakers	4.16 kV Metal-Clad SWGR	27.6 kV Metal-Clad SWGR	Pad-Mount Reclosers
MS 1	29	N/A	29	29	24	N/A
MS 2	14	N/A	N/A	N/A	N/A	15
MS 3	1	1	N/A	N/A	N/A	1
MS 4	22	N/A	20	20	20	N/A
MS 5	46	1	27	27	27	N/A
MS 6	11	N/A	44	44	N/A	N/A
MS 7	59	N/A	7	7	59	N/A
MS 8	5	N/A	N/A	N/A	N/A	4
MS 9	4	N/A	N/A	N/A	N/A	3
MS 10	31	N/A	45	45	11	N/A
MS 11	7	N/A	N/A	N/A	N/A	1
MS 12	8	16	25	25	N/A	N/A
MS 14	6	N/A	N/A	N/A	N/A	6

4.2.1 Power Transformers

HI Formulation

Power transformers tend to be the most critical assets owned by an LDC. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect tens of thousands of customers.

Degradation mechanisms include loss of insulation or oil quality due to overload or low-level internal faults causing heating, arcing, and/or physical deterioration such as corrosion or failed cooling systems. Power transformers are the most tested and tracked utility assets and reliable indicators of the impending need for maintenance or replacement include Dissolved Gas Analysis ("DGA"), Oil Quality ("OQ"), and Power Factor ("PF") testing. Some tests can be conducted in-service and others required taking the asset out of service. Many features such as cooling fans are external to the tank and can be maintained in situ.

The HI for power transformers is calculated based on EOL criteria summarized in Table 4-14.

Table 4-14: Power Transformers HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
DGA	20	A,B,C,D,E	4,3,2,1,0	80
Oil Quality	16	A,C,E	4,2,0	64
Service Age	7	A,B,C,D,E	4,3,2,1,0	28
Load History	7	A,B,C,D,E	4,3,2,1,0	28
Oil Leaks	5	A,E	4,0	20
Condition of Enclosure	4	A,E	4,0	16
Condition of Cooling Equipment[3]	4	A,E	4,0	16
IR Scan	3	A,B,C,D,E	4,3,2,1,0	12
Oil Level	3	A,E	4,0	12
Condition of Foundation	1	A,E	4,0	4
Condition of Grounding	1	A,E	4,0	4
Total Score				**284**

Data Collection and Assumptions

The HI for power transformers was calculated using asset data, IR reports, and inspection results. A comprehensive DGA and OQ report was also provided to METSCO. DGA and OQ results were not available for one asset. WHESC confirmed this was a new asset and testing was scheduled for July/August 2023. The average DAI for power transformers is 100%.

[3] Condition of Cooling Equipment only considered for power transformers with fans.

Results

Since station power transformers tend to be critical assets, they may need attention to manage the risk on the system. WHESC owns 16 power transformers and valid HI results were calculated for all power transformers. The HI distribution for WHESC's power transformers can be seen in Figure 4-22, which shows 0 power transformers are in Very Poor Condition. It was assumed that WHESC's new power transformer was in Very Good condition. All power transformers in Fair condition or higher.

TUL results for power transformers can be seen in Figure 4-23, which shows that 2 power transformers are Past TUL. The TUL for power transformers is 45 years. Power Transformers within 15 years of TUL were classified as Approaching TUL.

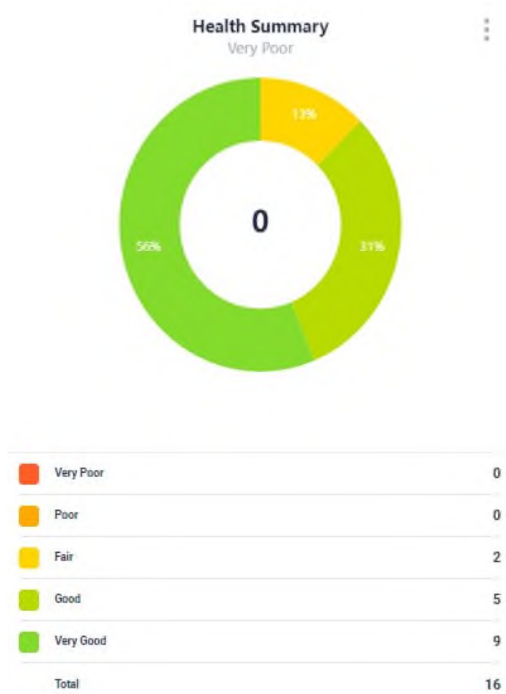


Figure 4-22: Power Transformers HI Results

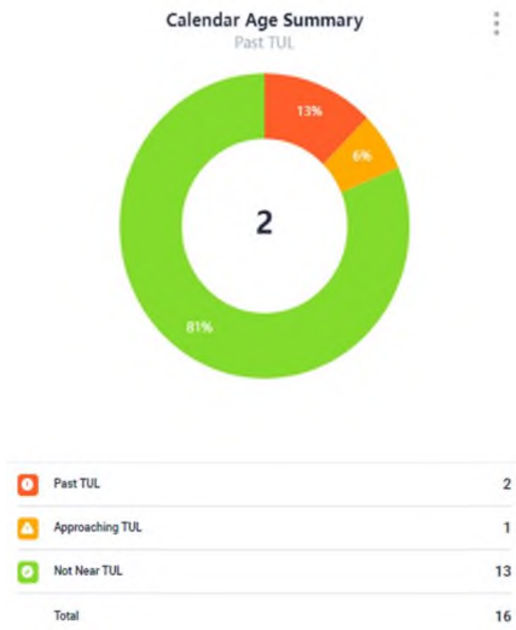


Figure 4-23: Power Transformers Demographic Results

4.2.2 Circuit Breakers

HI Formulation

Circuit breakers are critical substation assets and are the primary protective devices for maintaining public safety and protecting other station equipment. Breakers work with station relays to open, either in a fault situation, as directed by the operations center, or as part of the automation scheme. Breaker degradation occurs primarily through physical processes, such as corrosion, accumulation of debris on insulators, or operations under load. In general, the more current passing through the breaker when it operates, the more wear and tear it sustains.

The HI for air and vacuum insulated circuit breakers are calculated based on EOL criteria summarized in Table 4-15 and Table 4-16 respectively.

Table 4-15: Air Circuit Break HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	5	A,B,C,D,E	4,3,2,1,0	20
Condition of Racking Mechanism	4	A,C,E	4,2,0	16
Condition of Control & Operating Mechanism	3	A,C,E	4,2,0	12
Arc Chutes	2	A,C,E	4,2,0	8
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**64**

Table 4-16: Vacuum Circuit Breaker HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Overall Condition	5	A,B,C,D,E	4,3,2,1,0	20
Condition of Racking Mechanism	4	A,C,E	4,2,0	16
Condition of Control & Operating Mechanism	3	A,C,E	4,2,0	12
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**56**

Data Collection and Assumptions

The HI for circuit breakers was calculated using asset data and substation maintenance reports provided by WHESC. The average DAI for both air circuit breakers and vacuum circuit breakers is 100%.

Results

WHESC owns 8 air circuit breakers and 25 vacuum circuit breakers. Valid HI results were calculated for all circuit breakers. The HI distributions for WHESC's air and vacuum circuit breakers are shown in Figure 4-24 and Figure 4-25 respectively. These figures show that there are 0 air circuit breakers and 0 vacuum circuit breakers in Very Poor condition. All circuit breakers are in Very Good condition.

TUL results for circuit breakers can be seen in Figure 4-26 and Figure 4-27 respectively. These figures show that 0 air circuit breakers and 0 vacuum circuit breakers are Past TUL. The TUL for circuit breakers is 45 years. Circuit breakers within 15 years of TUL were classified as Approaching TUL.

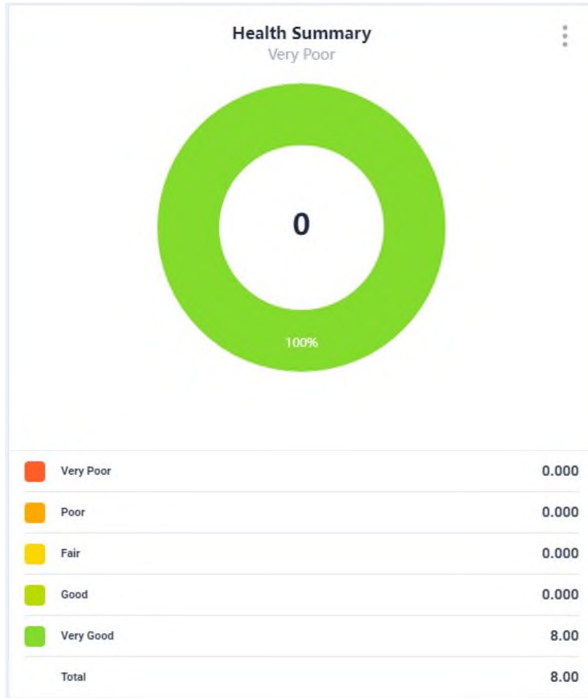


Figure 4-24: Air Circuit Breakers HI Results

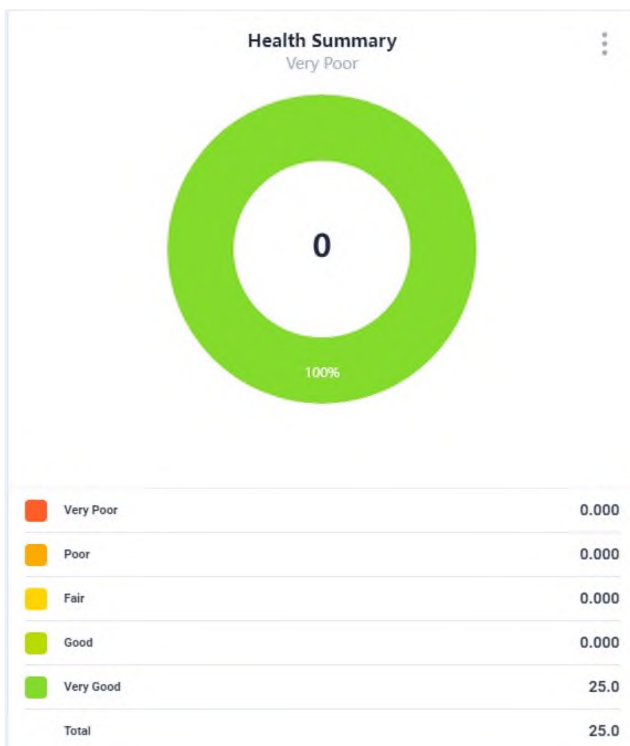


Figure 4-25: Vacuum Circuit Breakers HI Results

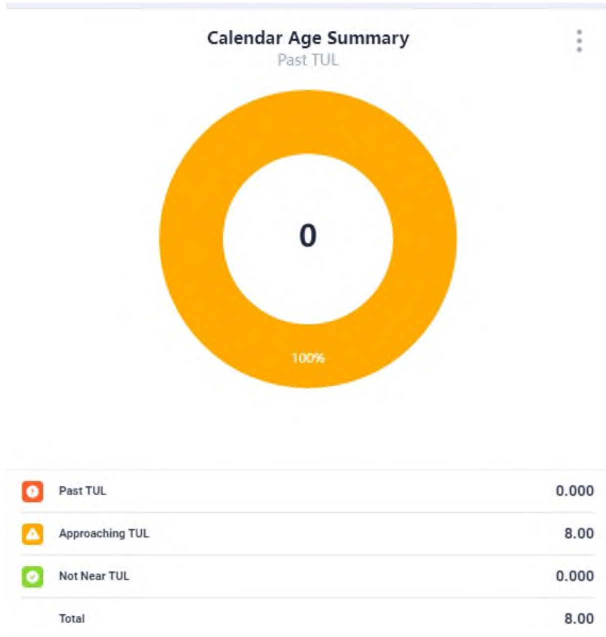


Figure 4-26: Air Circuit Breakers Demographic Results

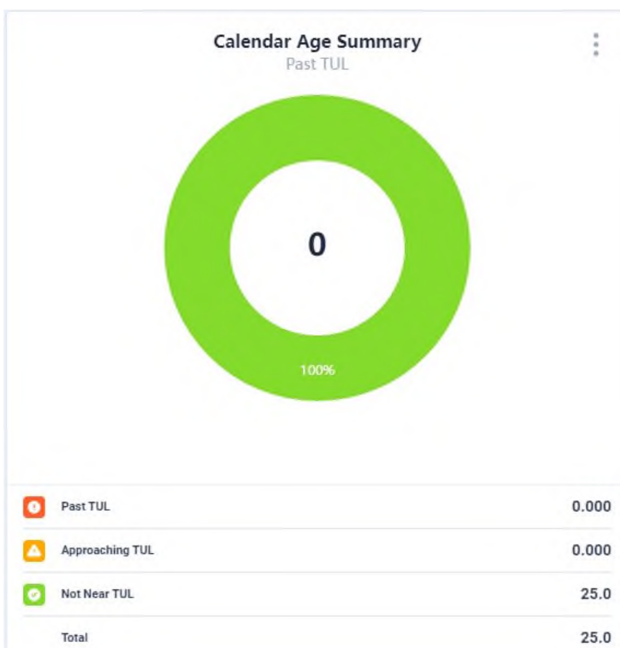


Figure 4-27: Vacuum Circuit Breakers Demographic Results

4.2.3 Metal-Clad Switchgears & Pad-mount Reclosers

HI Formulation

The HI for metal-clad switchgears and pad-mount reclosers was calculated by considering a combination of insulation resistance, service age, and inspection results. The HI formulation for metal-clad switchgears and pad-mount reclosers is summarized in Table 4-17.

Table 4-17 : Metal-Clad Switchgear & Pad-Mount Recloser HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Condition of Enclosure	3	A,C,E	4,2,0	12
Condition of Pad and Grounding	3	A,C,E	4,2,0	12
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Overall Condition	2	A,B,C,D,E	4,3,2,1,0	8
Total Score				**44**

Data Collection and Assumptions

The HI for metal-clad switchgears and pad-mount reclosers was calculated using asset data and substation maintenance reports provided by WHESC. The average DAI for both metal-clad switchgears and pad-mount reclosers is 100%.

Results – Metal-Clad Switchgears

WHESC owns 12 metal-clad switchgears and valid HI results were calculated for all assets. The HI distribution for WHESC's metal-clad switchgears can be seen in Figure 4-28, which shows that 0 metal-clad switchgears are in Very Poor condition. All metal-clad switchgears are in Fair condition or better.

TUL results for metal-clad switchgears can be seen in Figure 4-29, which shows 3 metal-clad switch gears are past TUL. The TUL for metal-clad switchgears is 40 years. Metal-clad switchgears within 13 years of TUL were classified as Approaching TUL.

Results – Pad-Mount Reclosers

WHESC owns 14 pad-mount reclosers and valid HI results were calculated for all assets. The HI distribution for WHESC's pad-mount reclosers can be seen in Figure 4-30, which shows that 0 pad-mount reclosers are in Very Poor condition. All pad-mount reclosers are in Very Good condition.

TUL results for pad-mount reclosers can be seen in Figure 4-31, which shows that 0 pad-mount reclosers are past TUL. The TUL for pad-mount reclosers is 30 years. Pad-mount reclosers within 10 years of TUL were classified as Approaching TUL.

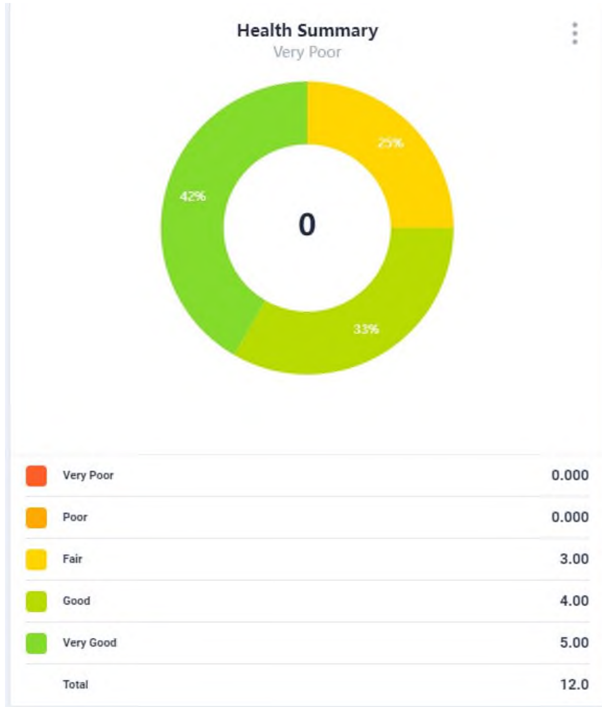


Figure 4-28: Metal-Clad Switchgears HI Results

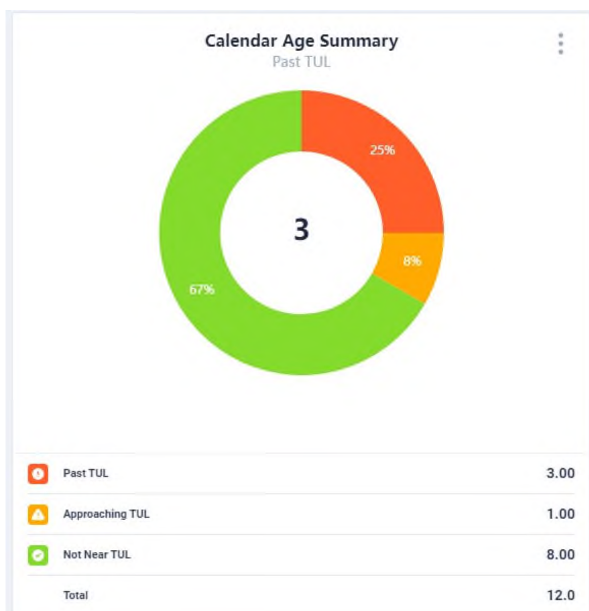


Figure 4-29: Metal-Clad Switchgears Demographic Results

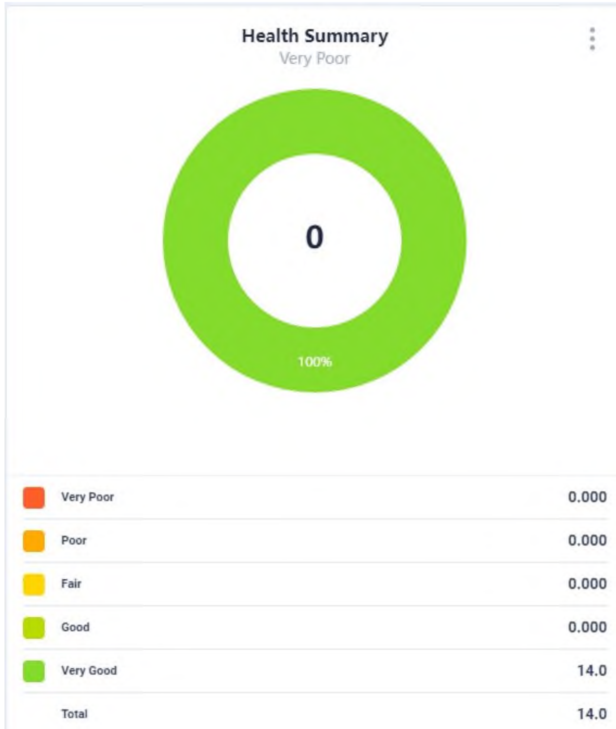


Figure 4-30: Pad-Mount Reclosers HI Results

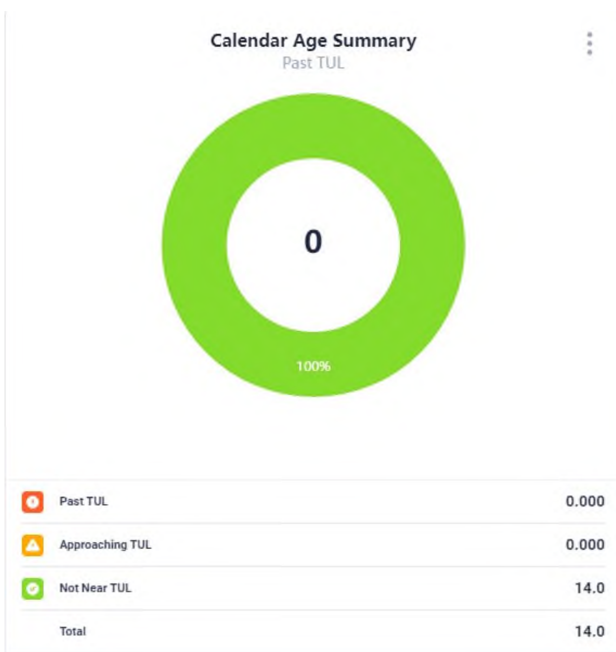


Figure 4-31: Pad-Mount Reclosers Demographic Results

5 Recommendations

A complete ACA framework for WHESC represents an integral component of its broader AM framework, enabling it to proactively manage its assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for WHESC's investment decision-making to be further enhanced with the current information regarding the state of the assets. There are also further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

The following sections target additional condition parameters that WHESC might consider implementing to work towards a best practice HI formulation for each asset class. Recommendations are also provided to improve the quality of data currently available to standardize the data collection process for future iterations of the ACA.

A general observation is noted that applies to all asset inspections - WHESC currently populates inspections with multiple grading schemes. One grade consists of: None, Minor, Major and OK; whereas another grading scheme consists of: None, Moderate, Extensive or Should Be Checked. METSCO recommends WHESC to incorporate a unified grading scheme across all asset inspections that uses five grading levels. A recommended grading can be: None/OK, Minor, Moderate, Extensive, and Needs Replacement. A five-level grading scheme will allow for more discrepancy between assets and their respective Health Index values that will be used for prioritizing assets.

5.1 Distribution Assets

5.1.1 Wood Poles

The data availability for WHESC's wood poles is very good. WHESC collects a substantial number of data parameters for wood poles that enable the production of an advanced HI formulation. Remaining strength determined through pole testing is one of the most informative end-of-life criteria for wood poles. WHESC has started performing Polux testing on the wood pole population in 2022 to replace the legacy sound and bore procedure. Polux testing was not available for all WHESC's wood poles in this iteration of the ACA. WHESC should prioritize performing Polux tests on all wood poles in its service territory. Only testing poles above a certain age threshold (e.g., fifteen years) is an approach commonly applied in the industry.

5.1.2 Concrete Poles

The data availability for WHESC's concrete poles is very good. The HI formulation used for concrete poles is consistent with the industry-best practice formulation.

5.1.3 Pad-Mounted and Pole-Trans Transformers

The data availability for WHESC's distribution transformers is very good. WHESC collects a substantial number of data parameters for distribution transformers that enable the production of an advanced HI formulation. WHESC should consider tracking the loading on their distribution transformers to enable peak loading to be utilized as a condition parameter in the HI formulation.

5.1.4 Distribution Switchgears

The data availability for WHESC's pad-mount switchgears is very good. WHESC collects a substantial number of data parameters for pad-mount transformers that enable the production of an advanced HI formulation which is consistent with industry best-practice.

5.1.5 Overhead Conductors

The HI formulation used for WHESC's OH conductors is aligned with industry best-practice. Although laboratory tests exist to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing and there is no need for WHESC to collect any additional condition parameters for this asset class. In the case of OH conductors, service age is used as the main input to estimate the tensile strength and remaining life of the asset.

5.1.6 Underground Cables

The data availability for WHESC's UG cables is very good. Service age provides a reasonably good measure of the remaining life of UG cables, while additional knowledge of past failure instances allows for comparison between cable segments of similar vintage.

Although several test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. WHESC may consider collecting the following condition parameters for UG cables to advance the HI formulation for the asset class:

- Field Tests
- Loading History

5.1.7 SCADA Switches

The data availability for WHESC's SCADA switches is very good. WHESC currently does not perform a detailed inspection of its SCADA switches as part of the OH line maintenance program. WHESC might consider performing a visual inspection of these assets in the future to advance the HI formulation for the asset class. The following condition parameters can be collected as part of a SCADA switch visual inspection:

- Condition of Blades
- Condition of Operating Mechanism

5.2 Station Assets

5.2.1 Power Transformers

Power transformers are a critical asset class and should be managed under the context of a thorough AM Plan. WHESC collects a substantial number of data parameters for power transformers that enable the production of an advanced HI formulation with very good data availability.

One area where the power transformer HI formulation is notably lacking is results of electrical tests. METSCO recommends that WHESC consider incorporating the following electrical tests into the power transformer maintenance program:

- Insulation Resistance
- Winding Resistance
- Bushing Power Factor
- Turns Ratio
- Transformer Dissipation Factor

There are several additional condition parameters that WHESC can collect moving forward to improve the accuracy of the power transformer HI and align the formulation with industry best-practices:

- Furans Analysis
- Winding Temperature
- Insulation Moisture Content
- Condition of Bushings
- Condition of Conservator
- Condition of Gaskets and Seals
- Condition of Transformer Connectors
- Condition of LTC

5.2.2 Circuit Breakers

The data availability for WHESC's circuit breakers is very good. Visual inspection data was provided for WHESC's circuit breakers in substation maintenance reports which are only available for MS 4, MS 5, and MS 6. Commissioning reports were also provided for circuit breakers at MS 3 and MS 11 which included some visual inspection results. Generally, commissioning reports are not used for the purpose of an ACA because they do not provide the results of regular maintenance programs that the utility performs on the asset. In this case, the circuit breakers at MS 3 and MS 11 were commissioned in 2022 so the visual inspections performed at the time of commissioning was taken as a reasonable input.

The visual condition of assets without maintenance or commissioning reports was field verified. WHESC should work towards documenting the results of substation maintenance at the following stations:

- MS 1
- MS 2
- MS 7
- MS 8
- MS 9
- MS 10
- MS 12
- MS 14

There are several additional condition parameters that WHESC can collect moving forward to improve the accuracy of the circuit breaker HI and align the formulation with industry best-practices:

- Breaker Timing Test

- Operations Counter Reading
- Equipment Failure History
- Vacuum Bottle Integrity (Applicable to vacuum interrupted breakers only)

5.2.3 Substation Switchgears & Reclosers

The data availability for WHESC's station switchgears & reclosers is very good. Visual inspection data was provided for three WHESC's switchgears in substation maintenance reports which are only available for MS 4, MS 5, and MS 6. Visual inspection results were field verified for the remaining assets. WHESC should work towards recording the results of substation maintenance at all stations where it is not currently available:

- MS 1
- MS 2
- MS 3
- MS 7
- MS 8
- MS 9
- MS 10
- MS 11
- MS 12
- MS 14

There are a couple of additional condition parameters that WHESC can collect moving forward to improve the accuracy of the station switchgear and recloser HI and align the formulation with industry best-practices:

- Equipment Failure History

6 Conclusion

This report not only includes a thorough assessment condition assessment of WHESC's major distribution and station asset classes, but also provides WHESC with a broad range of recommendations with respect to specific types of information that it may choose to collect as well as the metrics it may deploy to enhance it's AM analytics.

Keeping records of an assets' condition is good practice, as it may assist in planning and assessing the quality of assets being replaced in-service. METSCO recommends collecting and keeping condition records consistent for all assets inspected. This will help WHESC in both standardizing inspection results and quickly identifying and flagging issues within the system. Obtaining and organizing more comprehensive condition data records would establish a stronger baseline of the asset health indices and more robust, multi-parameter, HI formulations can be used that are in-line with standardized practice in the industry.

The results of this ACA give WHESC the resources they need to plan for short- and long-term care of their assets. This document will also assist WHESC in their decision-making process. Understanding asset health and condition is essential for risk assessment, program evaluation, and project prioritization.

It is important to note that since METSCO's previous ACA with WHESC in 2018, major improvements have been made with regards to their asset data. In most cases, the number of condition parameters used to calculate the HI has improved. In addition, WHESC also included SCADA switches as part of their regular inspection and testing. System HI has also shown major improvement compared to the 2018 ACA report.

This concludes METSCO's ACA report for WHESC's major distribution and substation assets. We thank WHESC's staff and management for the opportunity to participate in this complex study and for their ongoing support throughout its development.

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 in Concord, ON and our western office is located in Calgary, AB. We have satellite offices in Whitehorse, YK, and Houston, TX. 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.

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over ten years. Our founders are the pioneers of the first Health Index methodology for power equipment in North America as well as the most robust risk-based analytics on the market today for high-voltage assets. 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 Distribution System Plans as utility staff giving METSCO the qualified expertise to provide service to WHESC.

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

Appendix B: Condition Parameter Grading Tables

B1. Wood Poles

Table B - 1: Grading Table for Wood Pole Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 60 years
E	More than 60 years

Table B - 2: Grading Table for Wood Pole Polux Testing

Condition Rating	Corresponding Condition
A	RS >90%
B	80%< RS ≤90%
C	70%< RS ≤80%
D	60%< RS ≤70%
E	RS ≤60%

Table B - 3: Grading Table for Wood Pole Top Feathering

Condition Rating	Corresponding Condition
A	None
C	Moderate
E	Extensive

Table B - 4: Grading Table for Wood Pole Woodpecker Damage

Condition Rating	Corresponding Condition
A	None
C	Moderate
E	Extensive

Table B - 5: Grading Table for Wood Pole Insect Damage

Condition Rating	Corresponding Condition
A	None

C	Moderate
E	Extensive

Table B - 6: Grading Table for Wood Pole Cracks

Condition Rating	Corresponding Condition
A	None
C	Moderate
E	Extensive

Table B - 7: Grading Table for Wood Pole Lean

Condition Rating	Corresponding Condition
A	No
E	Yes

`

Table B - 8: Grading Table for Wood Pole Fire Damage

Condition Rating	Corresponding Condition
A	None
C	Moderate
E	Extensive

B2. Concrete Poles

Table B - 9: Grading Table for Concrete Pole Service Age

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 40 years
C	41 to 60 years
D	61 to 80 years
E	More than 80 years

`

Table B - 10: Grading Table for Concrete Pole Lean

Condition Rating	Corresponding Condition
A	No
E	Yes

B3. Pad-Mount Transformers

Table B - 11: Grading Table for Pad-Mount Transformer Service Age

Condition Rating	Corresponding Condition
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	More than 53 years

Table B - 12: Grading Table for Pad-Mount Transformer IR Scan

Condition Rating	Corresponding Condition
A	Not mentioned in IR report
C	Beginning of a Fault, ΔT: $\leq$ 5°C
D	Typical overheating, ΔT: 5°C - 30°C
E	Dangerously overheating, ΔT: > 30°C

Table B - 13: Grading Table for Pad-Mount Transformer Oil Leaks

Condition Rating	Corresponding Condition
A	None
E	Needs Attention

Table B - 14: Grading Table for Pad-Mount Transformer Corrosion

Condition Rating	Corresponding Condition
A	None
E	Major

Table B - 15: Grading Table for Pad-Mount Transformer Pad Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 16: Grading Table for Pad-Mount Transformer Enclosure Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 17: Grading Table for Pad-Mount Transformer Termination Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

`

Table B - 18: Grading Table for Pad-Mount Transformer Overall Condition

Condition Rating	Corresponding Condition
A	No Transformer Inspection Components Marked as "Needs Attention"
B	One Transformer Inspection Component Marked as "Needs Attention"
C	Two Transformer Inspection Components Marked as "Needs Attention"
D	Three Transformer Inspection Components Marked as "Needs Attention"
E	Four or More Transformer Inspection Components Marked as "Needs Attention"

B4. Pole-Trans

Table B - 19: Grading Table for Pole-Trans Service Age

Condition Rating	Corresponding Condition
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	More than 53 years

Table B - 20: Grading Table for Pole-Trans Non-Discretionary Obsolesence

Condition Rating	Corresponding Condition
A	The device meets present system design needs

E	The device does not meet present system design needs

Table B - 21: Grading Table for Pole-Trans IR Scan

Condition Rating	Corresponding Condition
A	Not mentioned in IR report
C	Beginning of a Fault, ΔT: ≤ 5°C
D	Typical overheating, ΔT: 5°C - 30°C
E	Dangerously overheating, ΔT: > 30°C

Table B - 22: Grading Table for Pole-Trans Oil Leaks

Condition Rating	Corresponding Condition
A	None
E	Needs Attention

Table B - 23: Grading Table for Pole-Trans Corrosion

Condition Rating	Corresponding Condition
A	None
E	Major

Table B - 24: Grading Table for Pole-Trans Structural Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 25: Grading Table for Pole-Trans Termination Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

`

Table B - 26: Grading Table for Pole-Trans Overall Condition

Condition Rating	Corresponding Condition

A	No Transformer Inspection Components Marked as "Needs Attention"
B	One Transformer Inspection Component Marked as "Needs Attention"
C	Two Transformer Inspection Components Marked as "Needs Attention"
D	Three Transformer Inspection Components Marked as "Needs Attention"
E	Four or More Transformer Inspection Components Marked as "Needs Attention"

B5. Distribution Switchgears

Table B - 27: Grading Table for Pad-Mount Switchgear IR Scan

Condition Rating	Corresponding Condition
A	Not mentioned in IR report
C	Beginning of a Fault, ΔT: $\leq 5°C$
E	Typical overheating, ΔT: 5°C - 30°C

Table B - 28: Grading Table for Pad-Mount Switchgear 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	More than 40 years

Table B - 29: Grading Table for Pad-Mount Switchgear Pad Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 30: Grading Table for Pad-Mount Switchgear Enclosure Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 31: Grading Table for Pad-Mount Switchgear Termination Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 32: Grading Table for Pad-Mount Switchgear Operating Mechanism Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 33: Grading Table for Pad-Mount Switchgear Blade Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 34: Grading Table for Pad-Mount Switchgear Overall Condition

Condition Rating	Corresponding Condition
A	No Switchgear Inspection Components Marked as "Needs Attention"
B	One Switchgear Inspection Component Marked as "Needs Attention"
C	Two Switchgear Inspection Components Marked as "Needs Attention"
D	Three Switchgear Inspection Components Marked as "Needs Attention"
E	Four or More Switchgear Inspection Components Marked as "Needs Attention"

B6. Overhead Conductors

Table B - 35: Grading Table for Overhead Conductor Service Age

Condition Rating	Corresponding Condition
A	0 to 20 years
B	21 to 40 years
C	41 to 60 years
D	61 to 80 years

E	More than 80 years

`

Table B - 36: Grading Table for Overhead Conductor Small Conductor Risk

Condition Rating	Corresponding Condition
A	Absence of small sized conductors
E	Presence of small sized conductors (#4 to #6 Cu or #4 ACSR)

B7. Underground Cables

Table B - 37: Grading Table for Underground Cable Service Age

Condition Rating	Corresponding Condition
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	More than 53 years

`

Table B - 38: Grading Table for Underground Cable Failure History

Condition Rating	Corresponding Condition
A	Segment is not linked to any fault reports
E	Segment is linked to one or more fault reports

Table B - 39: Grading Table for Underground Cable Feeder Failure History

Condition Rating	Corresponding Condition
A	Feeder has less than 0.5 failure per 10 km per year
B	Feeder has more than 0.5 and up to 1.0 failure per 10 km per year
C	Feeder has more than 1.0 and up to 2.0 failures per 10 km per year
D	Feeder has more than 2.0 and up to 4.0 failures per 10 km per year
E	Feeder has more than 4.0 failures per 10 km pear year

B8. SCADA Switches

Table B - 40: Grading Table for SCADA Switch Service Age

Condition Rating	Corresponding Condition
A	0 to 6 years
B	7 to 13 years
C	14 to 20 years
D	21 to 26 years
E	More than 26 years

Table B - 41: Grading Table for SCADA Switch IR Scan

Condition Rating	Corresponding Condition
A	Not mentioned in IR report
C	Beginning of a Fault, ΔT: ≤ 5°C
E	Typical overheating, ΔT: 5°C - 30°C

B9. Pole-Mount Reclosers

Table B - 42: Grading Table for Pole-Mount Reclosers Service Age

Condition Rating	Corresponding Condition
A	0 to 6 years
B	7 to 13 years
C	14 to 20 years
D	21 to 26 years
E	More than 26 years

Table B - 43: Grading Table for Pole-Mount Reclosers IR Scan

Condition Rating	Corresponding Condition
A	Not mentioned in IR report
C	Beginning of a Fault, ΔT: ≤ 5°C
E	Typical overheating, ΔT: 5°C - 30°C

B10. Power Transformers

Table B - 44: Gas Concentration (ppm) Limits for Power Transformers[4]

Gas	O2/N2 Ratio <= 0.2				O2/N2 Ratio >0.2			
	Transformer Age in Years				Transformer Age in Years			
	Unknown	1-9	10-30	>30	Unknown	1-9	10-30	>30
H_2	80	75		100	40	40		
CH_4	90	45	90	110	20	20		
C_2H_6	90	30	90	150	15	15		
C_2H_4	50	20	50	90	50	25	60	
C_2H_2	1	1			2	2		
CO	900	900			500	500		
CO_2	9000	5000	10000		5000	3500	5500	

Table B - 45: Gas Rate of Change Limits for Power Transformers (ppm)[4]

Gas	Maximum (ppm) variation between consecutive DGA samples	
	O2/N2 Ratio <= 0.2	O2/N2 Ratio >0.2
H_2	40	25
CH_4	30	10
C_2H_6	25	7
C_2H_4	20	
C_2H_2	Any Increase	
CO	250	175
CO_2	2500	1750

Table B - 46: Criteria for Power Transformer DGA Results

Condition Rating	Corresponding Condition
A	All parameters within acceptable limits
B	1 parameter does not meet acceptability limits
C	2 parameters do not meet acceptability limits
D	3 parameters do not meet acceptability limits

[4] IEEE Std. C57.104, "IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers," 2019.

E	4 or more parameters do not meet acceptability limits

Table B - 47: Grading Table for Power Transformer Oil Quality

Test	Station Transformer Voltage Class	Grade
	U ≤ 69 kV	
Acid Number	≤0.05	A
	0.05-0.20	C
	≥0.20	E
Interfacial Tension [mN/m]	≥30	A
	25-30	C
	≤25	E
Dielectric Strength [kV]	>40 (2 mm gap)	A
	≤40	E
Water Content [ppm]	<35	A
	≥35	E

Table B - 48: Grading Table for Power Transformer Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 60 years
E	More than 60 years

Table B - 49: Grading Table for Power Transformer Load History

Condition Rating	Corresponding Condition
A	Peak Load <50% Capacity
B	50%≤ Peak Load <75%
C	75%≤ Peak Load <100%
D	100%≤ Peak Load <125%
E	Peak Load ≥125%

Table B - 50: Grading Table for Power Transformer Oil Leaks

Condition Rating	Corresponding Condition

A	None
E	Needs Attention

Table B - 51: Grading Table for Power Transformer Enclosure Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 52: Grading Table for Power Transformer Cooling Equipment Condition[5]

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 53: Grading Table for Power Transformer IR Scan

Condition Rating	Corresponding Condition
A	Not mentioned in IR report
C	Beginning of a Fault, ∆T: ≤ 5°C
E	Typical overheating, ∆T: 5°C - 30°C

`

Table B - 54: Grading Table for Power Transformer Oil Level

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

Table B - 55: Grading Table for Power Transformer Foundation Condition

Condition Rating	Corresponding Condition
A	OK
E	Needs Attention

`

Table B - 56: Grading Table for Power Transformer Grounding Condition

Condition Rating	Corresponding Condition

[5] Only applicable for power transformers with fans.

A	OK
E	Needs Attention

B11. Circuit Breakers

Table B - 57: Grading Table for Circuit Breaker Overall Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Table B - 58: Grading Table for Circuit Breaker Racking Mechanism Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

`

Table B - 59: Grading Table for Circuit Breaker Control and Operating Mechanism Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Table B - 60: Grading Table for Circuit Breaker Service Age

Condition Rating	Corresponding Condition
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 60 years
E	More than 60 years

`

Table B - 61: Grading Table for Circuit Breaker Arc Chutes[6]

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

B12. Metal-Clad Switchgears

Table B - 62: Grading Table for Station Switchgear Service Age

Condition Rating	Corresponding Condition
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	More than 53 years

Table B - 63: Grading Table for Station Switchgear Pad and Grounding Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Table B - 64: Grading Table for Station Switchgear Enclosure Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Table B - 65: Grading Table for Station Switchgear Overall Condition

Condition Rating	Corresponding Condition

[6] Only applicable for air-interrupted circuit breakers.

A	OK
C	FAIR
E	POOR

B13. Pad-Mount Reclosers

Table B - 66: Grading Table for Pad-Mount Recloser 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	More than 40 years

Table B - 67: Grading Table for Pad-Mount Recloser Pad and Grounding Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

`

Table B - 68: Grading Table for Pad-Mount Recloser Enclosure Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Table B - 69: Grading Table for Pad-Mount Recloser Overall Condition

Condition Rating	Corresponding Condition
A	OK
C	FAIR
E	POOR

Appendix 5-I: Fleet Assessment

METSCO

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Appendix C: Fleet Assessment

Welland Hydro

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P-23-144 | Revision 0

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Executive Summary

This Fleet Assessment report is prepared for Welland Hydro-Electric System Corporation's ("WHESC") by METSCO Energy Solutions Inc. ("METSCO"). The purpose of the study is to quantify the remaining life and condition of each fleet asset based on the data received from WHESC in November 2023.

The fleet assets classes covered in the report include the following:

1. Pick-up Trucks
2. Cargo Vans
3. Mini Vans
4. Bucket Trucks
5. Digger Trucks
6. Trailers
7. Wheel Loaders
8. Forklift Trucks
9. Backyard Diggers

The remaining life was of each fleet asset was calculated based on its service age, milage, or engine-hours. The condition of WHESC's fleet assets were quantified based on the results of an Asset Condition Assessment ("ACA"). Health Index ("HI") scores were calculated based on the provided asset demographics, visual inspection results, and maintenance records. Fleet assets were classified as one of five condition categories: Very Good, Good, Fair, Poor, or Very Poor.

The HI Distribution of WHESC's fleet assets are presented In Figure E – 1. The results of the fleet assessment are summarized in Table E – 1.

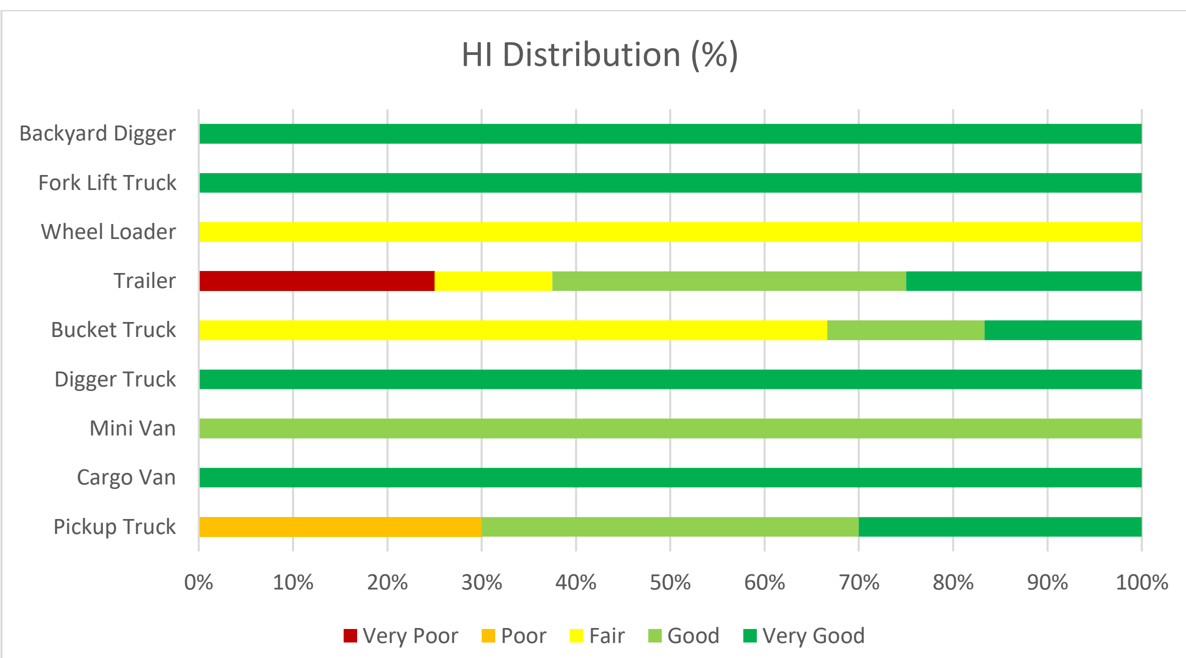

Figure E–- 1: Health Index Results

Table E–- 1: Fleet Assessment Results

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
LV-1	2011 GMC Canyon	Pickup Truck	0%	45%	Poor
LV-3	2010 GMC Sierra	Pickup Truck	0%	40%	Poor
LV-24	2018 Ford F-250	Pickup Truck	40%	85%	Very Good
LV-36	2017 GMC Sierra	Pickup Truck	30%	80%	Good
LV-37	2016 Ford F-150	Pickup Truck	20%	73%	Good
LV-42	2020 Chevrolet Silverado	Pickup Truck	60%	78%	Good
LV-44	2019 Ford Transit 150	Cargo Van	50%	85%	Very Good
LV-51	2022 Ford F-150 P/U	Pickup Truck	80%	90%	Very Good
LV-52	2022 Ford F-150 P/U	Pickup Truck	80%	90%	Very Good
LV-53	2011 GMC Sierra P/U	Pickup Truck	0%	33%	Poor
LV-54	2016 Ford F-150 P/U	Pickup Truck	20%	80%	Good
LV-60	2015 Nissan NV200	Mini Van	10%	73%	Good
HV-4	2010 Freightliner M2 106	Bucket Truck	0%	58%	Fair
HV-9	2016 Freightliner M2 106	Bucket Truck	47%	71%	Good
HV-11	2012 Freightliner M2 106	Bucket Truck	20%	64%	Fair
HV-15	2009 International 4400	Bucket Truck	0%	55%	Fair
HV-18	2019 Freightliner M2 108	Digger Truck	67%	90%	Very Good
HV-31	2017 Freightliner	Digger Truck	53%	86%	Very Good
HV-46	2021 Freightliner M2 106	Bucket Truck	80%	90%	Very Good
HV-55	2013 Freightliner	Bucket Truck	27%	68%	Fair
TR-6	2017 Dump Trailer	Trailer	65%	78%	Good
TR-27	2024 Dump Trailer	Trailer	100%	90%	Very Good
TR-29	2019 Sauber Reel Trailer	Trailer	75%	90%	Very Good
TR-33	1991 Nicholls Trailer	Trailer	0%	20%	Very Poor
TR-35	1982 Lge. Reel Trailer	Trailer	0%	20%	Very Poor
TR-56	2014 Brooks PTB	Trailer	50%	78%	Good
TR-58	2009 H&H Trailer	Trailer	25%	60%	Fair
TR-59	2015 Nichols Trailer	Trailer	55%	78%	Good
OT-32	2005 New Holland	Wheel Loader	55%	63%	Fair
OT-43	2002 Hyster Lift Truck	Fork Lift Truck	93%	85%	Very Good
OT-57	2005 Altec DB35	Backyard Digger	92%	85%	Very Good

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List of Acronyms and Abbreviations

The following acronyms are used within the Asset Condition Assessment report:

Acronym	Definition
ACA	Asset Condition Assessment
HI	Health Index
HV	Heavy Duty Vehicle
LV	Light Duty Vehicle
METSCO	METSCO Energy Solutions Inc.
OT	Other
TR	Trailer
WHESC	Welland Hydro-Electric System Corporation.

1 Introduction

This report summarizes the results of a Fleet Assessment study carried out by METSCO Energy Solutions Inc. ("METSCO") on behalf of Welland Hydro-Electric System Corporation ("WHESC"). The purpose of the study is to quantify the remaining life and condition of WHESC's fleet assets.

The following fleet vehicle types are covered in this report:

1. Pick-up Trucks
2. Cargo Vans
3. Mini Vans
4. Bucket Trucks
5. Digger Trucks
6. Trailers
7. Wheel Loaders
8. Forklift Trucks
9. Backyard Diggers

The remaining life of each vehicle was calculated based on demographic information provided by WHESC. The condition of each vehicle was assessed using a combination of asset demographics, visual inspections, and maintenance records. All data was collected by WHESC and were sent to METSCO in November 2023.

1.1 Assets Demographics

WHESC's fleet includes 31 vehicles that are currently in service. These are divided into four vehicle classes: Light Duty ("LV"), Heavy Duty ("HV"), Trailer ("TR"), and Other ("OT"). A detailed summary of the demographics of each fleet asset is shown in Table 1-1.

Table 1-1: WHESC Fleet Assets

Fleet Asset	Vehicle Model	Vehicle Type	Age (Years)	Mileage (km)	Engine Hours
LV-1	2011 GMC Canyon	Pickup Truck	13	121,725	N/A
LV-3	2010 GMC Sierra	Pickup Truck	14	147,596	N/A
LV-24	2018 Ford F-250	Pickup Truck	6	20,064	N/A
LV-36	2017 GMC Sierra	Pickup Truck	7	43,652	N/A
LV-37	2016 Ford F-150	Pickup Truck	8	83,662	N/A
LV-42	2020 Chevrolet Silverado	Pickup Truck	4	22,261	N/A
LV-44	2019 Ford Transit 150	Cargo Van	5	21,967	N/A
LV-51	2022 Ford F-150	Pickup Truck	2	17,774	N/A
LV-52	2022 Ford F-150	Pickup Truck	2	5,508	N/A
LV-53	2011 GMC Sierra	Pickup Truck	13	88,686	N/A
LV-54	2016 Ford F-150	Pickup Truck	8	59,762	N/A
LV-60	2015 Nissan NV200	Mini Van	9	100,615	N/A
HV-4	2010 Freightliner M2 106	Bucket Truck	14	294,966	7,029
HV-9	2016 Freightliner M2 106	Bucket Truck	8	31,739	5,926
HV-11	2012 Freightliner M2 106	Bucket Truck	12	135,705	9,288

Fleet Asset	Vehicle Model	Vehicle Type	Age (Years)	Mileage (km)	Engine Hours
HV-15	2009 International 4400	Bucket Truck	15	164,187	13,636
HV-18	2019 Freightliner M2 108	Digger Truck	5	22,815	2,358
HV-31	2017 Freightliner	Digger Truck	7	22,997	3,606
HV-46	2021 Freightliner M2 106	Bucket Truck	3	27,135	534
HV-55	2013 Freightliner	Bucket Truck	11	42,781	7,656
TR-6	2017 Dump Trailer	Trailer	7	N/A	N/A
TR-27	2024 Dump Trailer	Trailer	0	N/A	N/A
TR-29	2019 Sauber Reel Trailer	Trailer	5	N/A	N/A
TR-33	1991 Nicholls Trailer	Trailer	33	N/A	N/A
TR-35	1982 Lge. Reel Trailer	Trailer	42	N/A	N/A
TR-56	2014 Brooks PTB	Trailer	10	N/A	N/A
TR-58	2009 H&H Trailer	Trailer	15	N/A	N/A
TR-59	2015 Nichols Trailer	Trailer	9	N/A	N/A
OT-32	2005 New Holland	Wheel Loader	19	N/A	5,389
OT-43	2002 Hyster Lift Truck	Fork Lift Truck	22	N/A	788
OT-57	2005 Altec DB35	Backyard Digger	19	N/A	934

2 Methodology

The remaining life of fleet assets is calculated in terms of service age, mileage, or engine-hours. Service age was considered for all fleet assets. Mileage was considered for both light-duty and heavy-duty vehicles. Engine-hours was considered for vehicles classified as heavy-duty or other. Typical fleet asset lifecycles are listed below in terms of service age, mileage, and engine-hours by vehicle type. The typical useful life of each fleet asset was provided by WHESC. The remaining life of the asset was taken as the lower of the remaining life calculated based on service age, mileage, and engine-hours.

Table 2-1: Typical Fleet Asset Lifecycles

Fleet Asset	Class	Typical Useful Life (Years)	Mileage (km)	Engine Hours
Pick-up Trucks	LV	10	180,000	N/A
Mini Van	LV	10	120,000	N/A
Cargo Van	LV	10	140,000	N/A
Diggers	HV	15	195,000	12,000
Bucket Trucks	HV	15	210,000	12,000
Trailers	TR	20	N/A	N/A
Wheel Loader	OT	N/A	N/A	12,000
Forklift Truck	OT	N/A	N/A	10,000
Backyard Digger	OT	N/A	N/A	12,000

The Health Index ("HI) of each fleet asset was calculated using the same methodology presented in METSCO's 2023 ACA for WHESC's distribution and station assets. HI scores were calculated based on the provided asset demographics, visual inspection results, and maintenance records.

3 Fleet Assessment Results

This section presents the current Health Index Formulation ("HIF") for each fleet asset class, the calculated HI scores, remaining life, and reviews the data available to perform the study. The HI distribution for WHESC's fleet assets is summarized in Figure 3-1.

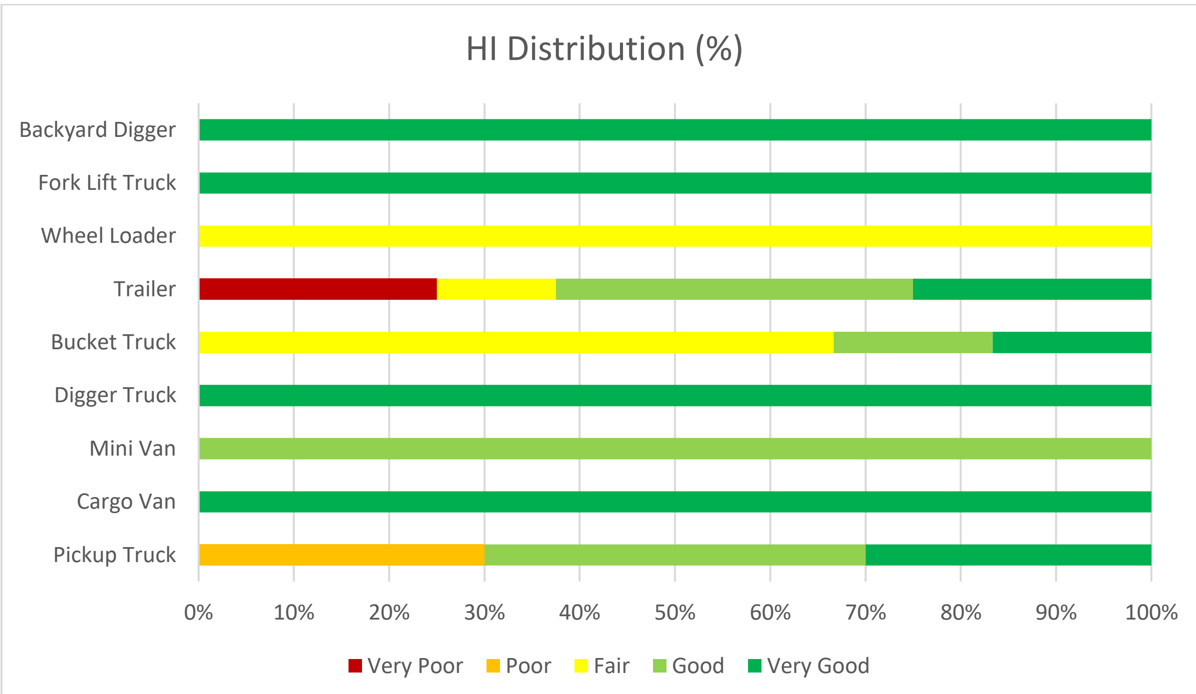

Figure 3-1: Health Index Results

3.1 Light Duty

HI Formulation

The HI for WHESC's light-duty vehicles is based on the HIF summarized in Table 3-1.

Table 3-1: HI Algorithm Light Duty Vehicles

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	28
Mileage	6	A,B,C,D,E	4,3,2,1,0	12
Body Condition	3	A,C,E	4,2,0	12
Interior Condition	2	A,C,E	4,2,0	8

Rust	1	A,C,E	4,2,0	4
Maintenance	4	A,C,E	4,2,0	16
Total Score				**80**

Results – Light Duty Vehicles

WHESC fleet comprises of 12 light-duty vehicles that are currently in service, this includes pick-up trucks, a cargo van, and a mini van. The remaining life and health index of WHESC's light-duty vehicles are shown in Table 3-2.

Table 3-2: Light Duty Vehicle Fleet Assessment Results

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
LV-1	2011 GMC Canyon	Pickup Truck	0%	45%	Poor
LV-3	2010 GMC Sierra	Pickup Truck	0%	40%	Poor
LV-24	2018 Ford F-250	Pickup Truck	40%	85%	Very Good
LV-36	2017 GMC Sierra	Pickup Truck	30%	80%	Good
LV-37	2016 Ford F-150	Pickup Truck	20%	73%	Good
LV-42	2020 Chevrolet Silverado	Pickup Truck	60%	78%	Good
LV-44	2019 Ford Transit 150	Cargo Van	50%	85%	Very Good
LV-51	2022 Ford F-150	Pickup Truck	80%	90%	Very Good
LV-52	2022 Ford F-150	Pickup Truck	80%	90%	Very Good
LV-53	2011 GMC Sierra	Pickup Truck	0%	33%	Poor
LV-54	2016 Ford F-150	Pickup Truck	20%	80%	Good
LV-60	2015 Nissan NV200	Mini Van	10%	73%	Good

3.2 Heavy Duty

HI Formulation

The HI for WHESC's heavy-duty vehicles is based on the HIF summarized in Table 3-3.

Table 3-3: HI Algorithm Heavy Duty Vehicles

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	28
Mileage	3	A,B,C,D,E	4,3,2,1,0	8
Engine Hours	4	A,B,C,D,E	4,3,2,1,0	4
Body Condition	3	A,C,E	4,2,0	12
Interior Condition	2	A,C,E	4,2,0	8
Rust	1	A,C,E	4,2,0	4
Maintenance	4	A,C,E	4,2,0	16
Total Score				**80**

Results – Heavy Duty Vehicles

WHESC fleet comprises of 8 heavy-duty vehicles that are currently in service, this includes bucket trucks and diggers. The remaining life and health index of WHESC's heavy-duty vehicles are shown in Table 3-4.

Table 3-4: Heavy Duty Vehicle Fleet Assessment Results

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
HV-4	2010 Freightliner M2 106	Bucket Truck	0%	58%	Fair
HV-9	2016 Freightliner M2 106	Bucket Truck	47%	71%	Good
HV-11	2012 Freightliner M2 106	Bucket Truck	20%	64%	Fair
HV-15	2009 International 4400	Bucket Truck	0%	55%	Fair
HV-18	2019 Freightliner M2 108	Digger Truck	67%	90%	Very Good
HV-31	2017 Freightliner	Digger Truck	53%	86%	Very Good
HV-46	2021 Freightliner M2 106	Bucket Truck	80%	90%	Very Good
HV-55	2013 Freightliner	Bucket Truck	27%	68%	Fair

3.3 Trailer

HI Formulation

The HI for WHESC's trailers is based on the HIF summarized in Table 3-5.

Table 3-5: HI Algorithm Trailers

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Body Condition	4	A,C,E	4,2,0	16
Rust	2	A,C,E	4,2,0	8
Maintenance	4	A,C,E	4,2,0	16
Total Score				**80**

Results – Trailers

WHESC fleet comprises of 8 trailers that are currently in service. The remaining life and health index of WHESC's heavy-duty vehicles are shown in Table 3-6.

Table 3-6: Trailers Fleet Assessment Results

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
TR-6	2017 Dump Trailer	Trailer	65%	78%	Good
TR-27	2024 Dump Trailer	Trailer	100%	90%	Very Good
TR-29	2019 Sauber Reel Trailer	Trailer	75%	90%	Very Good
TR-33	1991 Nicholls Trailer	Trailer	0%	20%	Very Poor
TR-35	1982 Lge. Reel Trailer	Trailer	0%	20%	Very Poor

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
TR-56	2014 Brooks PTB	Trailer	50%	78%	Good
TR-58	2009 H&H Trailer	Trailer	25%	60%	Fair
TR-59	2015 Nichols Trailer	Trailer	55%	78%	Good

3.4 Other

HI Formulation

The HI for WHESC's forklift & wheel loader is based on the HIF summarized in Table 3-7. The HI for WHESC's backyard digger is based on HIF summarized in

Table **3-8**.

Table 3-7: HI Algorithm Forklifts & Wheel Loaders

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Body Condition	3	A,C,E	4,2,0	12
Interior Condition	2	A,C,E	4,2,0	8
Rust	1	A,C,E	4,2,0	4
Maintenance	4	A,C,E	4,2,0	16
Total Score				**80**

Table 3-8: HI Algorithm Backyard Diggers

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Body Condition	4	A,C,E	4,2,0	16
Rust	2	A,C,E	4,2,0	8
Maintenance	4	A,C,E	4,2,0	16
Total Score				**80**

Results – Other

WHESC's Other vehicle class comprises of 3 vehicles that are currently in service, this includes a forklift, wheel loader, and a backyard digger. The remaining life and health index of WHESC's other vehicles are shown in Table 3-9.

Table 3-9: Other Fleet Assessment Results

Fleet Asset	Vehicle Model	Vehicle Type	Remaining Life	HI Score (%)	Condition
OT-32	2005 New Holland	Wheel Loader	55%	63%	Fair
OT-43	2002 Hyster Lift Truck	Forklift Truck	93%	85%	Very Good
OT-57	2005 Altec DB35	Backyard Digger	92%	85%	Very Good

Appendix A: Fleet Assessment Condition Parameter Grading Tables

A1. Light Duty Vehicles

Table A - 1: Service Age Grading Table for Light Duty Vehicles

Condition Rating	Corresponding Condition
A	0 to 3 years
B	4 to 6 years
C	7 to 10 years
D	11 to 13 years
E	More than 13 years

Table A - 2: Mileage Grading Table for Pickup Trucks

Condition Rating	Corresponding Condition
A	0 to 60,000 km
B	60,001 to 120,000 km
C	120,001 to 180,000 km
D	180,001 to 240,000 km
E	More than 240,000 km

Table A - 3: Mileage Grading Table for Mini Vans

Condition Rating	Corresponding Condition
A	0 to 40,000 km
B	40,001 to 80,000 km
C	80,001 to 120,000 km
D	120,001 to 160,000 km
E	More than 160,000 km

Table A - 4: Mileage Grading Table for Cargo Vans

Condition Rating	Corresponding Condition
A	0 to 46,666 km
B	46,667 to 93,333 km
C	93,334 to 140,000 km
D	140,001 to 186,666 km
E	More than 186,666 km

Table A - 5: Body and Interior Condition Grading Table for Light Duty Vehicles

Condition Rating	Corresponding Condition
A	GOOD
C	FAIR
E	POOR

Table A - 6: Rust Grading Table for Light Duty Vehicles

Condition Rating	Corresponding Condition
A	OK
C	MINOR
E	MODERATE

Table A - 7: Maintenance Grading Table for Light Duty Vehicles

Condition Rating	Corresponding Condition
A	BELOW AVERAGE
C	AVERAGE
E	ABOVE AVERAGE

A2. Heavy Duty Vehicles

Table A - 8: Service Age Grading Table for Heavy Duty Vehicles

Condition Rating	Corresponding Condition
A	0 to 5 years
B	6 to 10 years
C	11 to 15 years
D	16 to 20 years
E	More than 20 years

Table A – 9: Mileage Grading Table for Diggers

Condition Rating	Corresponding Condition
A	0 to 65,000 km
B	65,001 to 130,000 km
C	130,001 to 195,000 km
D	195,000 to 260,000 km
E	More than 260,000 km

Table A - 10: Mileage Grading Table for Bucket Trucks

Condition Rating	Corresponding Condition
A	0 to 70,000 km
B	70,001 to 140,000 km
C	140,001 to 210,000 km
D	210,001 to 280,000 km
E	More than 280,000 km

Table A – 11: Engine Hours Grading Table for Diggers & Bucket Trucks

Condition Rating	Corresponding Condition
A	0 to 4,000 hours
B	4,001 to 8,000 hours
C	8,001 to 12,000 hours
D	12,001 to 16,000 hours
E	More than 16,000 hours

Body and Interior Condition Grading for Heavy Duty Vehicles – See Table A-5

Rust Grading for Heavy Duty Vehicles – See Table A-6

Maintenance Grading for Heavy Duty Vehicles – See Table A-7

A3. Trailers

Table A - 12: Service Age Grading Table for Trailers

Condition Rating	Corresponding Condition
A	0 to 6 years
B	7 to 13 years
C	14 to 20 years
D	21 to 26 years
E	More than 26 years

Body Condition Grading for Trailers – See Table A-5

Rust Grading for Trailers – See Table A-6

Maintenance Grading for Trailers – See Table A-7

A4. Other

Table A - 13: Engine Hours Grading Table for Wheel Loaders & Backyard Diggers

Condition Rating	Corresponding Condition
A	0 to 4,000 hours
B	4,001 to 8,000 hours
C	8,001 to 12,000 hours
D	12,001 to 16,000 hours
E	More than 16,000 hours

Table A - 14: Engine Hours Grading Table for Forklift Trucks

Condition Rating	Corresponding Condition
A	0 to 3,333 hours
B	3,334 to 6,666 hours
C	6,667 to 10,000 hours
D	10,001 to 13,333 hours
E	More than 13,333 hours

Body and Interior Condition Grading for Other Vehicles – See Table A-5

Rust Grading for Other Vehicles – See Table A-6

Maintenance Grading for Other Vehicles – See Table A-7